August 29, 2013

Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Attention: Mr. Bruce McLennan
Board Chairman

Dear Sir:

RE: Yukon Electrical 2013-2015 General Rate Application
Information Responses

In accordance with Board Order 2013-06, Yukon Electrical has attached the consolidated package of information responses.

Please note that Yukon Electrical has amended its response to YEC-YECL-6(f) since its filing on August 8, 2013. The amended response has been included in the attached consolidated package of information responses.

If you have any questions on the above, please contact me at (780) 733-2489.

Yours truly,

Original Signed by

James Grattan, CA
Director, Regulatory

CW-YECL-1

Reference: Sales and Revenue, YECL Application, Page 2-4

In its Application, YECL states:

> The forecast process involves the review of historic sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. The information is obtained through Yukon Electrical's work in the community, as well as consultation with the City of Whitehorse, Yukon Government, and various local agencies and developers.

The City requires an understanding of the communications and consultations used in developing forecast sales.

Request:

(a) Please provide copies of all communications with "the City of Whitehorse, Yukon Government, and various local agencies and developers" related to sales forecasts. If there are no written communications, please provide summaries of verbal communications.

Response:

(a) As noted in the Application, Yukon Electrical's sales, and associated capital forecast, takes into account consultations with City of Whitehorse and Yukon Government officials as well as local developers that allow Yukon Electrical to identify customer additions. The Company's involvement with the local Chamber of Commerce also serves to identify projects that will result in new distribution extensions and or new customers. While this process has been in place for many years, it has taken on added importance of late as customers have recognized the importance of communicating their plans to Yukon Electrical given the long lead times required to obtain key pieces of electrical infrastructure. The information received as part of these consultations allows Yukon Electrical to identify what, if any, additional resources may be required to meet customer's capital needs and reflect new customers and load in its sales forecast.

The key information obtained from the City of Whitehorse and the Yukon Territorial Government (YTG) was their respective capital plans. The City of Whitehorse's plan provides information related to development in the Whitehorse area while the YTG plan provides government development plans for projects throughout the Yukon. As noted above, the capital plan information allows Yukon Electrical to identify what, if any, additional resources may be required to meet customers capital needs and reflect new customers and load in its sales forecast.

Regarding communication with the YTG and other agencies, Yukon Electrical relied on published materials from the Government and information through media (TV, newspapers). For the published materials, please refer to YUB-YECL-56 and the Canada Mortgage and Housing Corporation website (http://www.cmhc-schl.gc.ca/odpub/esub/65446/65446_2012_A01.pdf?lang=en), Northern Housing Report, released in 2012.

CW-YECL-2

Reference: Sales and Revenue, Application, Page 2-5

In its Application, YECL states:

> Over the past 2-3 years, housing developments in Whitehorse have been using electricity for space heating, which has resulted in an increase in residential average UPC. As a result, in forecasting Whitehorse UPC in 2013, Yukon Electrical used the 2012 weather-normalized UPC, which already reflects the consumption increases due to space heating, as a base and raising it by the most recent three-year average growth in weather-normalized UPC. The increase in UPC relating to electric space heating, however, is not expected to be extended beyond 2013, as it is expected to be offset by a reduction in consumption due to the demand side management program. 17 Attachments 1 to 21 show the historical data as well as the regression results.

It appears that there has been a shift in the use of electricity, with newer houses using electricity for space heating. Based on the shift, there may well be different usage patterns for the different uses. The City requires information to assess the forecast of sales, based for the various uses.

Request:

(a) Please provide a schedule similar to Schedule 2.1 containing 2008, 2009, 2010, 2011, and 2012 actual, and 2013-2015 forecast actual and normalized sales, average customers and actual and normalized average use per customer for the City of Whitehorse, separating customers that use electricity for space heating and those that do not use electricity for space heating.

(b) Please provide the response to (a) above in Excel format

(c) Please provide Attachments 1 to 21 in Excel format with formulae intact.

Response:

(a - b) Please refer to CW-YECL-2(a) Attachment 1 for the City of Whitehorse actual and forecast data in a format similar to Schedule 2.1. As noted on pages 2-5 and 2-6 of the Application, Whitehorse residential and commercial UPC and energy forecasts for the test period are all weather-normalized. A non-weather-normalized forecast is not available. In addition, please note the UPC and sales numbers included in the attachment for the City of Whitehorse are only available on a billed energy basis. As the forecast for lighting is not calculated on a community basis, but rather on an aggregate basis for all of Yukon Electrical by rate code, Yukon Electrical is not able to provide a forecast solely for the City of Whitehorse. Yukon Electrical does not have a breakdown of data for customers who use electricity for space heating and those who do not.

(c) Please refer to YUB-YECL-57 Attachments 1 to 21.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue for the City of Whitehorse (Billed Basis)

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013 Existing	Test Period 2014 Existing	Test Period 2015 Existing
1	**Residential**								
2	Customers (average during year)	9,500	9,704	9,906	10,185	10,525	10,792	10,975	11,161
3	Sales in MWh	101,946	106,262	104,737	115,951	119,094	120,955	123,009	125,097
4	MWh sales per customer	10.73	10.95	10.57	11.39	11.32	11.21	11.21	11.21
7	**Commercial**								
8	Customers (average during year)	1,782	1,814	1,869	1,926	1,988	2,031	2,055	2,087
9	Sales in MWh	120,275	121,391	123,231	130,152	133,847	136,539	139,517	142,565
10	MWh sales per customer	67.51	66.92	65.93	67.57	67.32	67.23	67.89	68.31
11	**Industrial**								
12	Customers (average during year)	-	-	-	-	-	1	1	1
13	Sales in MWh	-	-	-	-	-	1,025	4,620	4,620
14	MWh sales per customer	-	-	-	-	-	1,025	4,620	4,620
15	**Street Lights**								
16	Sales in MWh	2,688	2,731	2,843	2,865	2,919			
17	**Private Lights**								
18	Sales in MWh	428	401	403	390	372			
19	**Total Company - Retail - Primary**								
20	Customers	11,282	11,518	11,775	12,111	12,513	12,823	13,030	13,248
21	Sales in MWh	225,337	230,785	231,214	249,358	256,231	258,519	267,146	272,282
22	**Secondary Sales**								
23	Customers (average during year)	22	21	21	14	2	-	-	-
24	Sales in MWh	18,053	16,843	10,153	552	1,993	-	-	-
25	MWh sales per customer	820.59	802.05	483.48	39.43	996.50	-	-	-
26	**Total Company**								
27	Customers	11,304	11,539	11,796	12,125	12,515	12,823	13,030	13,248
28	Sales in MWh	243,390	247,628	241,367	249,910	258,224	257,494	262,526	267,662

CW-YECL-3

Reference: Sales and Revenue, Application, page 2-6

In its Application, YECL states:

> Twelve new large commercial customers (demand > 100kW) are anticipated to be added during the test period; eleven in Whitehorse and one in Watson Lake. Yukon Electrical has considered each of these new large customers individually, and forecast the load each will bring to the system each year based on the start-up time and other pertinent information provided by the customer. To forecast Whitehorse and Watson Lake commercial energy sales over the test period, Yukon Electrical has first determined the base energy sales for each community, which is forecast by multiplying the forecast customer counts (excluding the new large customer additions), by the corresponding community base year UPC forecast. The base year UPC for Watson Lake is obtained based on the most recent three-year actual UPC. For Whitehorse, the 2012 normalized UPC is used as a base year UPC. This is because of conversion of several secondary commercial customers to primary in recent years makes it inappropriate to use a three-year average. The commercial energy sales for Whitehorse and Watson Lake are then calculated by adding the base energy sales in each year to the specific energy sales of the new large commercial additions.

The City requires information to assess the forecast of Commercial sales.

Request:

(a) Please provide the forecast and timing of the sales to the twelve new large customers.

(b) Please provide the calculation of the forecast of commercial sales by community, before the impact of the twelve new customers is added. Please provide the response in Excel format, with formulae and links intact.

(c) Please reconcile the information provided in response to (a) and (b) above to the total commercial sales in Schedule 2.1

Response:

(a - c) On page 2-6 of the Application, Yukon Electrical inadvertently reported that there were 12 large commercial customers expected to be added during the test period. In fact, the correct number is 10 large commercial customers (9 in Whitehorse and 1 in Watson Lake) are expected to be added during the test period. Please refer to CW-YECL-3 Attachment 1 for the requested details on the commercial sales forecast.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Summary of 2013 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy (MWh)	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2013	2013				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	79	2,454			79	2,454	1.017	2,497
Carcross	62	1,241			62	1,241	1.013	1,257
Haines Junction	128	3,576			128	3,576	1.014	3,627
Teslin	71	1,942			71	1,942	1.021	1,984
Upper Liard	14.128	233			14	233	1.024	239
Destruction Bay	48	867			48	867	1.018	883
Whitehorse (1)	2,028	135,543	3	996	2,031	136,539	1.017	138,909
Beaver Creek	36	882			36	882	1.013	893
Watson Lake	173	6,221	1	210	174	6,431	1.017	6,538
Old Crow	41	866			41	866	1.017	881
Keno City	124,405	10			124,405	10	1.003	10
Stewart Crossing	264,010	20			264,010	20	1.021	21
Lower Post B.C.	248,741	18			248,741	18	1.019	18
Ross River	1,252,611	26			1,252,611	26	1.017	27
Pelly Crossing	1,009,884	36			1,009,884	36	1.021	37
Swift River	176,776	13			176,776	13	1.019	13
Tagish	255,389	11			255,389	11	1.021	11
Marsh Lake	347,164	14			347,164	14	1.020	14
Deep Creek	40,869	20			40,869	20	1.002	20
Minto Landing	68,476	22			68,476	22	1.018	22
TOTAL GENERAL S	3,791,004	154,014		1,206	3,791,007	155,220		157,899

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table B: Summary of 2014 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2014	2014				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	80	2,489			80	2,489	1.017	2,532
Carcross	63	1,258			63	1,258	1.013	1,274
Haines Junction	130	3,626			130	3,626	1.014	3,678
Teslin	72	1,971			72	1,971	1.021	2,013
Upper Liard	14.377	237			14	237	1.024	243
Destruction Bay	49	880			49	880	1.018	895
Whitehorse (1)	2,050	137,009	5	2,508	2,055	139,517	1.017	141,939
Beaver Creek	37	897			37	897	1.013	909
Watson Lake	174	6,270	1	420	175	6,690	1.017	6,801
Old Crow	42	878			42	878	1.017	893
Keno City	126,255	10			126,255	10	1.003	10
Stewart Crossing	267,646	20			267,646	20	1.021	21
Lower Post B.C.	251,608	18			251,608	18	1.019	18
Ross River	1,270,836	26			1,270,836	26	1.017	27
Pelly Crossing	1,024,101	36			1,024,101	36	1.021	37
Swift River	179,237	13			179,237	13	1.019	13
Tagish	258,857	11			258,857	11	1.021	11
Marsh Lake	351,759	14			351,759	14	1.020	14
Deep Creek	41,435	20			41,435	20	1.002	20
Minto Landing	75,428	22			75,428	22	1.018	22
TOTAL GENERAL S	3,849,873	155,704		2,928	3,849,879	158,631.9		161,369

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table C: Summary of 2015 Commercial Forecast

	Base Customers	Base Billed Energy Fcst (MWh)	Specific Customer Adds (annual average)	Specific Customer Energy	Total Customers	Billed Energy Fcst (MWh)	Billed to Earned Factor	Earned Energy Fcst (MWh)
Communities	2015	2015				TOTAL		TOTAL
1	2=Schedule 4	3=Schedule 4	4=Schedule 2	5=Schedule 2	6=2+4	7=3+5	8=Schedule 5	9=7x8
Carmacks	81	2,525			81	2,525	1.017	2,569
Carcross	64	1,276			64	1,276	1.013	1,293
Haines Junction	132	3,678			132	3,678	1.014	3,731
Teslin	73	2,002			73	2,002	1.021	2,045
Upper Liard	14.716	243			15	243	1.024	249
Destruction Bay	50	893			50	893	1.018	909
Whitehorse (1)	2,079	138,950	7	3,615	2,087	142,565	1.017	145,040
Beaver Creek	38	914			38	914	1.013	926
Watson Lake	177	6,366	1	420	178	6,786	1.017	6,899
Old Crow	42	891			42	891	1.017	906
Keno City	128,296	10			128,296	10	1.003	10
Stewart Crossing	271,640	20			271,640	20	1.021	21
Lower Post B.C.	255,393	18			255,393	18	1.019	18
Ross River	1,290,344	26			1,290,344	26	1.017	27
Pelly Crossing	1,039,400	36			1,039,400	36	1.021	37
Swift River	181,938	13			181,938	13	1.019	13
Tagish	262,612	11			262,612	11	1.021	11
Marsh Lake	356,711	14			356,711	14	1.020	14
Deep Creek	42,194	20			42,194	20	1.002	20
Minto Landing	82,922	22			82,922	22	1.018	22
TOTAL GENERAL S	3,914,200	157,927		4,035	3,914,208	161,962		164,757

Schedule 2.1

Notes: (1) For Whitehorse Base customer values, please see Schedule 3

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Specific Customer Adds

	2013 Additional Energy				2014 Additional Energy			2015 Additional Energy		Customers			2013 Add'l Energy	Customers	
	Cust 1 (kWh)	Cust 2 (kWh)	Cust 3 (kWh)	Cust 4 (kWh)	Cust 5 (kWh)	Cust 6 (kWh)	Cust 7 (kWh)	Cust 8 (kWh)	Cust 9 (kWh)	Total	Average		Cust 1 (kWh)	Total	Average
Jan-13										-		Jan-13		-	
Feb-13										-		Feb-13		-	
Mar-13										-		Mar-13		-	
Apr-13	22,630									1		Apr-13		-	
May-13	22,630									1		May-13		-	
Jun-13	22,630	16,164	48,493	48,493						4		Jun-13		-	
Jul-13	22,630	16,164	48,493	48,493						4		Jul-13	35,040	1	
Aug-13	22,630	16,164	48,493	48,493						4		Aug-13	35,040	1	
Sep-13	22,630	16,164	48,493	48,493						4		Sep-13	35,040	1	
Oct-13	22,630	16,164	48,493	48,493						4		Oct-13	35,040	1	
Nov-13	22,630	16,164	48,493	48,493						4		Nov-13	35,040	1	
Dec-13	22,630	16,164	48,493	48,493						4	3	Dec-13	35,040	1	1
Jan-14	22,630	22,630	67,890	67,890						4		Jan-14	35,040	1	
Feb-14	22,630	22,630	67,890	67,890						4		Feb-14	35,040	1	
Mar-14	22,630	22,630	67,890	67,890						4		Mar-14	35,040	1	
Apr-14	22,630	22,630	67,890	67,890						4		Apr-14	35,040	1	
May-14	22,630	22,630	67,890	67,890						4		May-14	35,040	1	
Jun-14	22,630	22,630	67,890	67,890						4		Jun-14	35,040	1	
Jul-14	22,630	22,630	67,890	67,890						4		Jul-14	35,040	1	
Aug-14	22,630	22,630	67,890	67,890						4		Aug-14	35,040	1	
Sep-14	22,630	22,630	67,890	67,890						4		Sep-14	35,040	1	
Oct-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Oct-14	35,040	1	
Nov-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Nov-14	35,040	1	
Dec-14	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7	5	Dec-14	35,040	1	1
Jan-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jan-15	35,040	1	
Feb-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Feb-15	35,040	1	
Mar-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Mar-15	35,040	1	
Apr-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Apr-15	35,040	1	
May-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		May-15	35,040	1	
Jun-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jun-15	35,040	1	
Jul-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Jul-15	35,040	1	
Aug-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Aug-15	35,040	1	
Sep-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Sep-15	35,040	1	
Oct-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260			7		Oct-15	35,040	1	
Nov-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260	25,550	25,550	9		Nov-15	35,040	1	
Dec-15	22,630	22,630	67,890	67,890	22,630	43,800	45,260	25,550	25,550	9	7	Dec-15	35,040	1	1
Annual Totals										**Total**		**Annual Totals**			
2013-F	203,670	113,150	339,450	339,450	-	-	-	-	-	995,720		2013-F	210,240		
2014-F	271,560	271,560	814,680	814,680	67,890	131,400	135,780	-	-	2,507,550		2014-F	420,480		
2015-F	271,560	271,560	814,680	814,680	271,560	525,600	543,120	51,100	51,100	3,614,960		2015-F	420,480		

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Jan-98	1,649	6,510	6,406	10,735,219	1165.7
Feb-98	1,636	5,639	5,803	9,225,150	719.1
Mar-98	1,648	5,698	5,738	9,389,723	756.6
Apr-98	1,645	5,168	5,217	8,501,373	458.6
May-98	1,666	4,594	4,667	7,653,575	270.6
Jun-98	1,655	4,661	4,720	7,714,120	119.5
Jul-98	1,643	5,020	5,022	8,247,191	111.6
Aug-98	1,644	4,590	4,557	7,545,936	189.2
Sep-98	1,642	4,964	4,946	8,151,291	327.8
Oct-98	1,654	4,837	4,813	8,000,105	557.7
Nov-98	1,663	5,346	5,381	8,890,864	792.3
Dec-98	1,672	5,404	5,288	9,036,054	1051.8
Jan-99	1,670	6,310	6,180	10,537,212	1,183
Feb-99	1,662	5,781	5,579	9,607,851	976
Mar-99	1,665	5,636	5,709	9,383,909	734
Apr-99	1,671	5,330	5,307	8,906,205	509
May-99	1,673	4,619	4,519	7,726,882	392
Jun-99	1,665	4,951	4,961	8,243,728	154
Jul-99	1,664	4,693	4,699	7,808,371	109
Aug-99	1,649	4,814	4,843	7,938,088	146
Sep-99	1,661	4,777	4,782	7,933,808	311
Oct-99	1,631	4,767	4,825	7,774,298	500
Nov-99	1,628	5,700	5,735	9,279,565	793
Dec-99	1,643	5,409	5,588	8,886,266	844
Jan-00	1,645	6,270	6,283	10,313,342	1,083
Feb-00	1,646	5,618	5,760	9,247,783	735
Mar-00	1,651	5,373	5,552	8,870,464	659
Apr-00	1,644	5,136	5,104	8,443,072	516
May-00	1,656	4,910	4,824	8,130,814	382
Jun-00	1,639	5,036	5,019	8,253,857	173
Jul-00	1,643	5,239	5,198	8,608,146	142
Aug-00	1,639	4,599	4,522	7,537,654	220
Sep-00	1,653	4,689	4,634	7,751,449	354
Oct-00	1,637	5,076	5,078	8,308,993	539
Nov-00	1,650	5,164	5,344	8,521,038	691
Dec-00	1,643	5,333	5,321	8,761,532	978
Jan-01	1,632	6,240	6,768	10,184,241	723
Feb-01	1,635	5,374	5,332	8,786,468	864
Mar-01	1,651	5,576	5,604	9,206,099	765
Apr-01	1,649	5,256	5,236	8,666,356	507
May-01	1,644	4,875	4,777	8,014,257	390
Jun-01	1,626	5,068	5,059	8,240,335	167
Jul-01	1,628	4,858	4,821	7,909,557	140
Aug-01	1,624	4,690	4,727	7,615,762	140
Sep-01	1,642	4,701	4,710	7,718,506	309
Oct-01	1,641	4,777	4,731	7,839,267	573
Nov-01	1,647	5,163	5,162	8,504,116	818
Dec-01	1,651	6,072	5,894	10,024,659	1,095
Jan-02	1,652	6,629	6,853	10,951,080	936

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Feb-02	1,644	5,650	5,664	9,288,783	825
Mar-02	1,653	5,655	5,462	9,348,209	921
Apr-02	1,650	5,824	5,596	9,609,869	653
May-02	1,657	4,990	4,933	8,268,251	362
Jun-02	1,665	4,981	4,960	8,292,927	176
Jul-02	1,660	4,834	4,809	8,024,723	131
Aug-02	1,656	5,117	5,093	8,474,109	183
Sep-02	1,649	4,695	4,696	7,741,980	314
Oct-02	1,674	4,779	4,917	8,000,187	444
Nov-02	1,671	5,344	5,678	8,930,222	583
Dec-02	1,660	5,252	5,429	8,717,761	845
Jan-03	1,659	6,122	6,269	10,156,110	989
Feb-03	1,663	5,473	5,584	9,100,970	757
Mar-03	1,675	5,560	5,490	9,313,508	835
Apr-03	1,663	5,639	5,609	9,377,998	514
May-03	1,687	4,799	4,740	8,096,541	364
Jun-03	1,655	5,197	5,152	8,601,844	193
Jul-03	1,662	4,875	4,916	8,102,548	84
Aug-03	1,658	4,831	4,810	8,010,231	181
Sep-03	1,664	4,981	4,918	8,288,208	359
Oct-03	1,657	4,913	5,019	8,140,663	467
Nov-03	1,670	5,714	5,632	9,542,613	875
Dec-03	1,675	6,035	6,118	10,108,563	912
Jan-04	1,675	6,331	6,096	10,605,074	1,258
Feb-04	1,669	5,889	6,084	9,827,952	697
Mar-04	1,678	5,723	5,769	9,603,827	754
Apr-04	1,673	5,679	5,717	9,500,870	467
May-04	1,683	4,923	4,993	8,284,611	273
Jun-04	1,685	5,261	5,371	8,864,143	84
Jul-04	1,675	5,388	5,443	9,024,437	74
Aug-04	1,673	5,198	5,290	8,696,604	102
Sep-04	1,689	4,971	4,897	8,396,465	368
Oct-04	1,704	4,903	4,903	8,353,942	541
Nov-04	1,700	5,552	5,691	9,438,374	720
Dec-04	1,692	5,929	6,029	10,031,917	900
Jan-05	1,695	6,545	6,441	11,094,349	1,166
Feb-05	1,703	5,834	5,890	9,934,638	795
Mar-05	1,713	5,579	5,824	9,556,887	614
Apr-05	1,701	5,451	5,508	9,271,969	453
May-05	1,711	5,227	5,320	8,942,598	257
Jun-05	1,699	4,921	4,930	8,360,369	154
Jul-05	1,703	5,073	5,045	8,639,652	133
Aug-05	1,700	5,043	5,065	8,573,524	151
Sep-05	1,719	5,110	5,133	8,784,835	299
Oct-05	1,710	5,023	5,033	8,589,960	535
Nov-05	1,720	5,827	5,905	10,022,927	763
Dec-05	1,707	5,698	5,948	9,726,467	794
Jan-06	1,712	6,646	6,640	11,377,324	1,096
Feb-06	1,710	5,773	5,792	9,872,441	821

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Mar-06	1,715	6,397	6,225	10,971,322	906
Apr-06	1,696	5,960	5,923	10,107,989	519
May-06	1,748	4,761	4,725	8,321,928	347
Jun-06	1,730	5,286	5,269	9,145,264	173
Jul-06	1,736	5,287	5,279	9,178,255	118
Aug-06	1,741	5,008	4,957	8,719,688	202
Sep-06	1,747	5,008	5,036	8,748,995	296
Oct-06	1,744	5,297	5,326	9,237,260	521
Nov-06	1,754	5,718	5,226	10,029,371	1,162
Dec-06	1,753	6,174	6,382	10,823,542	824
Jan-07	1,752	6,817	7,074	11,943,556	912
Feb-07	1,762	6,297	6,063	11,095,328	999
Mar-07	1,770	6,667	6,426	11,800,895	954
Apr-07	1,760	6,031	6,004	10,614,723	512
May-07	1,774	5,036	5,036	8,933,347	322
Jun-07	1,754	5,129	5,158	8,995,924	141
Jul-07	1,761	5,518	5,533	9,716,489	102
Aug-07	1,768	4,950	4,967	8,752,313	154
Sep-07	1,773	5,037	5,047	8,931,422	308
Oct-07	1,774	4,990	4,986	8,851,952	544
Nov-07	1,778	5,813	5,944	10,334,697	725
Dec-07	1,771	5,865	5,723	10,386,533	1,070
Jan-08	1,768	6,899	6,868	12,196,869	1,114
Feb-08	1,765	6,600	6,429	11,649,227	955
Mar-08	1,765	5,840	5,912	10,307,654	735
Apr-08	1,768	6,124	6,089	10,826,351	517
May-08	1,783	4,996	5,016	8,907,241	308
Jun-08	1,809	5,010	4,918	9,063,550	226
Jul-08	1,791	4,791	4,705	8,580,173	173
Aug-08	1,794	5,501	5,470	9,869,120	188
Sep-08	1,802	4,961	4,956	8,939,459	319
Oct-08	1,803	4,959	4,928	8,940,719	563
Nov-08	1,758	6,095	6,144	10,714,995	783
Dec-08	1,773	5,798	5,490	10,280,063	1,186
Jan-09	1,789	7,570	7,506	13,543,505	1,138
Feb-09	1,794	5,991	5,819	10,747,772	955
Mar-09	1,802	6,296	6,177	11,344,681	869
Apr-09	1,803	5,849	5,817	10,544,854	515
May-09	1,801	5,030	5,017	9,059,430	331
Jun-09	1,806	4,873	4,897	8,800,466	144
Jul-09	1,811	5,336	5,408	9,663,288	63
Aug-09	1,821	5,044	5,055	9,185,022	158
Sep-09	1,827	4,767	4,780	8,709,101	306
Oct-09	1,831	4,920	4,919	9,008,981	542
Nov-09	1,841	5,672	5,723	10,443,040	782
Dec-09	1,843	5,611	5,648	10,340,528	943
Jan-10	1,855	6,873	7,018	12,750,313	991
Feb-10	1,854	5,793	6,014	10,739,999	679
Mar-10	1,853	5,694	5,878	10,550,465	656

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial Customers	Customers	Actual UPC (kWh)	Normalized UPC (kWh)	Energy (kWh)	(Whitehorse) MHDD
Apr-10	1,872	5,852	5,898	10,955,417	461
May-10	1,882	5,064	5,106	9,529,520	292
Jun-10	1,878	5,075	5,059	9,530,854	172
Jul-10	1,888	4,885	4,879	9,223,514	117
Aug-10	1,883	4,927	4,955	9,277,423	146
Sep-10	1,796	5,003	4,978	8,985,101	332
Oct-10	1,873	5,088	5,117	9,529,688	520
Nov-10	1,902	5,773	5,915	10,980,325	718
Dec-10	1,894	5,902	5,628	11,178,789	1,163
Jan-11	1,895	7,318	7,436	13,868,531	1,010
Feb-11	1,901	5,885	5,784	11,187,292	906
Mar-11	1,904	6,638	6,472	12,639,624	902
Apr-11	1,914	5,638	5,612	10,790,977	511
May-11	1,920	5,379	5,416	10,328,077	296
Jun-11	1,926	5,025	5,025	9,677,894	161
Jul-11	1,924	4,935	4,914	9,494,900	128
Aug-11	1,933	4,867	4,793	9,408,841	218
Sep-11	1,944	5,020	5,001	9,758,502	329
Oct-11	1,937	5,224	5,264	10,119,093	513
Nov-11	1,956	5,624	5,454	11,001,007	936
Dec-11	1,961	6,057	6,335	11,877,662	775
Jan-12	1,964	7,288	7,252	14,314,241	1,118
Feb-12	1,964	6,086	6,267	11,953,663	708
Mar-12	1,971	5,990	6,032	11,806,946	756
Apr-12	1,967	5,947	6,007	11,697,409	451
May-12	1,993	5,350	5,309	10,663,094	351
Jun-12	1,970	5,063	5,007	9,974,100	200
Jul-12	2,003	4,956	4,918	9,927,438	140
Aug-12	2,005	4,808	4,819	9,639,853	158
Sep-12	1,997	4,626	4,666	9,238,345	287
Oct-12	2,005	5,242	5,113	10,510,210	631
Nov-12	2,013	5,613	5,395	11,298,741	970
Dec-12	2,005	6,396	6,072	12,822,998	1,197
Jan-13	2,015		7,252	14,614,192	
Feb-13	2,017		6,267	12,641,246	
Mar-13	2,020		6,032	12,185,918	
Apr-13	2,018		6,007	12,124,591	
May-13	2,030		5,309	10,778,962	
Jun-13	2,028		5,007	10,152,628	
Jul-13	2,031		4,918	9,987,718	
Aug-13	2,035		4,819	9,806,486	
Sep-13	2,038		4,666	9,508,869	
Oct-13	2,038		5,113	10,422,317	
Nov-13	2,036		5,395	10,984,488	
Dec-13	2,032		6,072	12,335,800	
Jan-14	2,034		7,252	14,750,718	
Feb-14	2,036		6,267	12,760,376	
Mar-14	2,040		6,032	12,302,686	
Apr-14	2,037		6,007	12,239,596	

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Whitehorse Base Commercial Forecast

Whitehorse	BASE (Before Large Adds)				
Base Commercial	Customers	Actual	Normalized	Energy	(Whitehorse)
Customers		UPC (kWh)	UPC (kWh)	(kWh)	MHDD
May-14	2,051		5,309	10,887,279	
Jun-14	2,048		5,007	10,253,419	
Jul-14	2,051		4,918	10,088,437	
Aug-14	2,057		4,819	9,911,974	
Sep-14	2,061		4,666	9,617,151	
Oct-14	2,063		5,113	10,546,320	
Nov-14	2,064		5,395	11,137,279	
Dec-14	2,061		6,072	12,514,241	
Jan-15	2,064		7,252	14,964,260	
Feb-15	2,065		6,267	12,945,216	
Mar-15	2,069		6,032	12,481,103	
Apr-15	2,067		6,007	12,416,972	
May-15	2,080		5,309	11,045,711	
Jun-15	2,078		5,007	10,402,494	
Jul-15	2,081		4,918	10,235,282	
Aug-15	2,086		4,819	10,051,552	
Sep-15	2,089		4,666	9,747,997	
Oct-15	2,090		5,113	10,684,650	
Nov-15	2,090		5,395	11,277,934	
Dec-15	2,091		6,072	12,696,929	
	Customers (annual avg)			Fcst Energy (kWh)	
2013-F	2,028			135,543,216	
2014-F	2,050			137,009,476	
2015-F	2,079			138,950,098	

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Carmacks

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	68	235,146	3,458
Feb-08	68	221,848	3,262
Mar-08	68	185,467	2,727
Apr-08	70	166,283	2,375
May-08	72	167,662	2,329
Jun-08	72	158,276	2,198
Jul-08	72	120,216	1,670
Aug-08	72	153,928	2,138
Sep-08	71	146,743	2,067
Oct-08	71	176,987	2,493
Nov-08	71	178,315	2,511
Dec-08	70	181,659	2,595
Jan-09	69	208,430	3,021
Feb-09	69	188,110	2,726
Mar-09	66	122,959	1,863
Apr-09	69	131,892	1,911
May-09	68	183,187	2,694
Jun-09	70	183,187	2,617
Jul-09	72	153,753	2,135
Aug-09	69	138,156	2,002
Sep-09	71	147,089	2,072
Oct-09	72	164,608	2,286
Nov-09	71	158,313	2,230
Dec-09	70	158,313	2,262
Jan-10	73	280,962	3,849
Feb-10	71	184,747	2,602
Mar-10	72	180,907	2,513
Apr-10	73	165,009	2,260
May-10	75	162,319	2,164
Jun-10	76	228,585	3,008
Jul-10	77	164,320	2,134
Aug-10	79	85,479	1,082
Sep-10	57	83,926	1,472
Oct-10	77	298,012	3,870
Nov-10	79	223,677	2,831
Dec-10	78	205,672	2,637
Jan-11	76	268,896	3,538
Feb-11	77	220,736	2,867
Mar-11	74	226,823	3,065
Apr-11	77	165,843	2,154
May-11	77	222,799	2,893
Jun-11	79	155,785	1,972
Jul-11	79	184,241	2,332
Aug-11	80	176,149	2,202
Sep-11	79	212,191	2,686
Oct-11	80	197,727	2,472
Nov-11	79	235,750	2,984
Dec-11	79	218,199	2,762
Jan-12	80	255,628	3,195
Feb-12	77	209,845	2,725
Mar-12	75	247,316	3,298
Apr-12	79	204,654	2,591
May-12	76	173,845	2,287
Jun-12	77	192,728	2,503
Jul-12	77	164,369	2,135
Aug-12	79	195,417	2,474
Sep-12	79	164,256	2,079
Oct-12	80	211,916	2,649
Nov-12	78	219,960	2,820
Dec-12	78	205,098	2,629

Carcross

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	47	92,691	1,972
Feb-08	47	102,377	2,178
Mar-08	45	78,164	1,737
Apr-08	48	80,697	1,681
May-08	51	79,027	1,550
Jun-08	52	79,150	1,522
Jul-08	55	86,515	1,573
Aug-08	57	98,673	1,731
Sep-08	56	84,268	1,505
Oct-08	64	82,157	1,284
Nov-08	52	75,940	1,460
Dec-08	49	90,002	1,837
Jan-09	48	103,483	2,156
Feb-09	46	97,483	2,119
Mar-09	48	89,376	1,862
Apr-09	47	86,000	1,830
May-09	56	117,181	2,093
Jun-09	56	79,644	1,422
Jul-09	57	95,273	1,671
Aug-09	57	84,624	1,485
Sep-09	56	87,061	1,555
Oct-09	54	92,626	1,715
Nov-09	52	68,826	1,324
Dec-09	48	81,965	1,708
Jan-10	48	93,702	1,952
Feb-10	48	97,073	2,022
Mar-10	48	83,495	1,739
Apr-10	48	79,796	1,662
May-10	57	76,503	1,342
Jun-10	57	82,284	1,444
Jul-10	58	87,157	1,503
Aug-10	58	82,690	1,426
Sep-10	58	102,151	1,761
Oct-10	56	81,327	1,452
Nov-10	50	91,347	1,827
Dec-10	48	95,210	1,984
Jan-11	48	128,469	2,676
Feb-11	50	93,657	1,873
Mar-11	50	131,485	2,630
Apr-11	57	101,202	1,775
May-11	58	86,082	1,484
Jun-11	61	101,218	1,659
Jul-11	60	83,273	1,388
Aug-11	60	84,352	1,406
Sep-11	59	93,479	1,584
Nov-11	60	81,050	1,351
Nov-11	54	78,677	1,457
Dec-11	55	113,921	2,071
Jan-12	56	91,494	1,634
Feb-12	56	122,699	2,191
Mar-12	56	98,185	1,753
Apr-12	59	87,421	1,482
May-12	59	85,896	1,456
Jun-12	61	86,001	1,410
Jul-12	63	90,330	1,434
Aug-12	64	85,103	1,330
Sep-12	63	77,070	1,223
Oct-12	62	76,217	1,229
Nov-12	62	88,296	1,424
Dec-12	62	99,243	1,601

Haines Junction

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	121	325,052	2,686
Feb-08	121	294,177	2,431
Mar-08	121	290,346	2,400
Apr-08	125	272,487	2,180
May-08	129	223,379	1,732
Jun-08	132	282,643	2,141
Jul-08	133	256,985	1,932
Aug-08	134	269,699	2,013
Sep-08	134	255,772	1,909
Oct-08	133	241,134	1,813
Nov-08	126	270,331	2,145
Dec-08	123	318,205	2,587
Jan-09	127	361,816	2,849
Feb-09	127	281,823	2,219
Mar-09	127	348,569	2,745
Apr-09	129	270,194	2,095
May-09	132	269,973	2,045
Jun-09	133	262,992	1,977
Jul-09	133	286,741	2,156
Aug-09	133	271,919	2,045
Sep-09	134	245,373	1,831
Oct-09	134	262,557	1,959
Nov-09	128	311,882	2,437
Dec-09	127	284,686	2,242
Jan-10	126	350,767	2,784
Feb-10	126	265,556	2,108
Mar-10	125	294,885	2,359
Apr-10	127	283,266	2,230
May-10	132	277,130	2,099
Jun-10	130	278,384	2,141
Jul-10	132	258,243	1,956
Aug-10	134	248,639	1,856
Sep-10	133	263,572	1,982
Oct-10	133	254,275	1,912
Nov-10	128	313,316	2,448
Dec-10	128	292,149	2,282
Jan-11	128	389,779	3,045
Feb-11	128	320,788	2,506
Mar-11	127	351,046	2,764
Apr-11	128	301,473	2,355
May-11	134	286,001	2,134
Jun-11	134	267,487	1,996
Jul-11	132	272,609	2,065
Aug-11	132	253,808	1,923
Sep-11	132	271,118	2,054
Nov-11	131	298,662	2,280
Nov-11	128	310,832	2,428
Dec-11	128	359,882	2,812
Jan-12	129	349,457	2,709
Feb-12	129	385,698	2,990
Mar-12	129	339,723	2,634
Apr-12	129	356,615	2,764
May-12	129	228,425	1,771
Jun-12	127	333,608	2,627
Jul-12	125	304,523	2,436
Aug-12	128	241,354	1,886
Sep-12	128	310,488	2,426
Oct-12	133	251,153	1,888
Nov-12	129	319,377	2,476
Dec-12	127	347,738	2,738

The Yukon Electrical Company Limited
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Carmacks

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	78	275,445	3,527
Feb-13	78	213,519	2,731
Mar-13	78	231,528	2,958
Apr-13	78	182,934	2,335
May-13	78	192,037	2,448
Jun-13	79	195,847	2,494
Jul-13	79	172,959	2,200
Aug-13	79	151,027	1,919
Sep-13	79	163,800	2,079
Oct-13	79	236,362	2,997
Nov-13	79	227,271	2,879
Dec-13	79	211,522	2,676
Jan-14	79	279,150	3,527
Feb-14	79	216,412	2,731
Mar-14	79	234,690	2,958
Apr-14	79	185,451	2,335
May-14	80	194,698	2,448
Jun-14	80	198,580	2,494
Jul-14	80	175,390	2,200
Aug-14	80	153,166	1,919
Sep-14	80	166,135	2,079
Oct-14	80	239,756	2,997
Nov-14	80	230,557	2,879
Dec-14	80	214,602	2,676
Jan-15	80	283,217	3,527
Feb-15	80	219,568	2,731
Mar-15	80	238,115	2,958
Apr-15	81	188,159	2,335
May-15	81	197,544	2,448
Jun-15	81	201,485	2,494
Jul-15	81	177,957	2,200
Aug-15	81	155,409	1,919
Sep-15	81	168,571	2,079
Oct-15	81	243,273	2,997
Nov-15	81	233,942	2,879
Dec-15	81	217,755	2,676

	Customers	Energy	Avg UPC
2013-F	79	2,454,250	31,239
2014-F	80	2,488,587	31,238
2015-F	81	2,524,995	31,238

Carcross

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	62	129,563	2,087
Feb-13	62	126,061	2,029
Mar-13	62	126,942	2,041
Apr-13	62	102,112	1,640
May-13	62	88,978	1,427
Jun-13	62	93,869	1,504
Jul-13	62	90,048	1,441
Aug-13	63	86,745	1,387
Sep-13	63	95,345	1,523
Oct-13	63	84,239	1,344
Nov-13	63	98,459	1,569
Dec-13	63	118,400	1,885
Jan-14	63	131,259	2,087
Feb-14	63	127,724	2,029
Mar-14	63	128,630	2,041
Apr-14	63	103,480	1,640
May-14	63	90,178	1,427
Jun-14	63	95,145	1,504
Jul-14	63	91,281	1,441
Aug-14	63	87,941	1,387
Sep-14	63	96,669	1,523
Oct-14	64	85,417	1,344
Nov-14	64	99,845	1,569
Dec-14	64	120,078	1,885
Jan-15	64	133,168	2,087
Feb-15	64	129,583	2,029
Mar-15	64	130,503	2,041
Apr-15	64	104,988	1,640
May-15	64	91,493	1,427
Jun-15	64	96,534	1,504
Jul-15	64	92,614	1,441
Aug-15	64	89,226	1,387
Sep-15	64	98,083	1,523
Oct-15	64	86,667	1,344
Nov-15	65	101,308	1,569
Dec-15	65	121,839	1,885

	Customers	Energy	Avg UPC
2013-F	62	1,240,761	19,872
2014-F	63	1,257,646	19,872
2015-F	64	1,276,005	19,872

Haines Junction

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	127	361,849	2,846
Feb-13	127	322,613	2,535
Mar-13	127	329,479	2,586
Apr-13	128	312,559	2,450
May-13	128	255,625	2,002
Jun-13	128	288,297	2,255
Jul-13	128	275,537	2,153
Aug-13	128	241,933	1,888
Sep-13	128	276,305	2,154
Oct-13	128	260,291	2,027
Nov-13	129	315,091	2,451
Dec-13	129	336,042	2,611
Jan-14	129	366,780	2,846
Feb-14	129	327,043	2,535
Mar-14	129	334,036	2,586
Apr-14	129	316,915	2,450
May-14	130	259,213	2,002
Jun-14	130	292,374	2,255
Jul-14	130	279,461	2,153
Aug-14	130	245,403	1,888
Sep-14	130	280,297	2,154
Oct-14	130	264,077	2,027
Nov-14	130	319,706	2,451
Dec-14	131	340,999	2,611
Jan-15	131	372,012	2,846
Feb-15	131	331,712	2,535
Mar-15	131	338,809	2,586
Apr-15	131	321,447	2,450
May-15	131	262,923	2,002
Jun-15	132	296,561	2,255
Jul-15	132	283,467	2,153
Aug-15	132	248,924	1,888
Sep-15	132	284,321	2,154
Oct-15	132	267,872	2,027
Nov-15	132	324,304	2,451
Dec-15	132	345,906	2,611

	Customers	Energy	Avg UPC
2013-F	128	3,575,620	27,950
2014-F	130	3,626,304	27,949
2015-F	132	3,678,258	27,949

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Teslin

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	66	220,160	3,336
Feb-08	66	219,812	3,330
Mar-08	66	147,735	2,238
Apr-08	72	135,464	1,881
May-08	76	165,074	2,172
Jun-08	79	122,645	1,552
Jul-08	78	131,460	1,685
Aug-08	78	149,971	1,923
Sep-08	78	125,108	1,604
Oct-08	82	145,567	1,775
Nov-08	67	180,680	2,697
Dec-08	69	193,687	2,807
Jan-09	68	233,026	3,427
Feb-09	61	206,649	3,388
Mar-09	70	200,059	2,858
Apr-09	74	191,713	2,591
May-09	77	158,150	2,054
Jun-09	77	122,767	1,594
Jul-09	77	147,605	1,917
Aug-09	77	132,777	1,724
Sep-09	77	136,847	1,777
Oct-09	78	177,110	2,271
Nov-09	70	186,573	2,665
Dec-09	69	186,388	2,701
Jan-10	69	232,990	3,377
Feb-10	69	217,890	3,158
Mar-10	68	197,759	2,908
Apr-10	72	200,870	2,790
May-10	74	127,137	1,718
Jun-10	77	132,809	1,725
Jul-10	77	135,649	1,762
Aug-10	77	120,304	1,562
Sep-10	75	161,500	2,153
Oct-10	76	128,809	1,695
Nov-10	69	150,694	2,184
Dec-10	68	207,231	3,048
Jan-11	67	216,649	3,234
Feb-11	68	172,050	2,530
Mar-11	68	204,761	3,011
Apr-11	72	156,663	2,176
May-11	74	157,402	2,127
Jun-11	77	125,865	1,635
Jul-11	77	155,130	2,015
Aug-11	76	126,337	1,662
Sep-11	76	148,165	1,950
Nov-11	77	141,950	1,844
Nov-11	73	172,572	2,364
Dec-11	73	182,419	2,499
Jan-12	73	231,512	3,171
Feb-12	74	184,836	2,498
Mar-12	71	201,328	2,836
Apr-12	69	161,008	2,333
May-12	76	128,792	1,695
Jun-12	77	150,812	1,959
Jul-12	78	133,981	1,718
Aug-12	78	124,243	1,593
Sep-12	78	151,839	1,947
Oct-12	79	144,168	1,825
Nov-12	73	214,556	2,939
Dec-12	70	208,877	2,984

Upper Liard

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	14	28,244	2,017
Feb-08	14	29,677	2,120
Mar-08	14	20,208	1,443
Apr-08	14	22,381	1,599
May-08	19	17,788	936
Jun-08	19	18,135	954
Jul-08	20	24,171	1,209
Aug-08	20	23,774	1,189
Sep-08	19	24,663	1,298
Oct-08	18	19,458	1,081
Nov-08	14	18,681	1,334
Dec-08	14	20,331	1,452
Jan-09	14	32,633	2,331
Feb-09	14	26,898	1,921
Mar-09	14	27,402	1,957
Apr-09	14	24,739	1,767
May-09	19	15,031	791
Jun-09	19	22,465	1,182
Jul-09	21	23,789	1,133
Aug-09	19	27,439	1,444
Sep-09	21	23,822	1,134
Oct-09	19	26,213	1,380
Nov-09	15	29,293	1,953
Dec-09	15	25,715	1,714
Jan-10	15	29,599	1,973
Feb-10	15	24,797	1,653
Mar-10	15	24,754	1,650
Apr-10	14	23,362	1,669
May-10	19	17,357	914
Jun-10	19	21,359	1,124
Jul-10	20	21,826	1,091
Aug-10	20	23,776	1,189
Sep-10	10	2,611	261
Oct-10	17	39,592	2,329
Nov-10	13	18,982	1,460
Dec-10	13	19,420	1,494
Jan-11	13	22,395	1,723
Feb-11	13	17,524	1,348
Mar-11	13	20,527	1,579
Apr-11	13	14,425	1,110
May-11	18	18,447	1,025
Jun-11	20	19,697	985
Jul-11	21	22,834	1,087
Aug-11	21	27,406	1,305
Sep-11	21	21,359	1,017
Nov-11	20	23,058	1,153
Nov-11	15	23,920	1,595
Dec-11	14	22,716	1,623
Jan-12	14	29,037	2,074
Feb-12	14	21,334	1,524
Mar-12	14	20,493	1,464
Apr-12	14	19,770	1,412
May-12	19	19,550	1,029
Jun-12	20	23,487	1,174
Jul-12	21	26,968	1,284
Aug-12	21	25,365	1,208
Sep-12	20	22,888	1,144
Oct-12	21	25,309	1,205
Nov-12	20	26,678	1,334
Dec-12	14	32,204	2,300

Destruction Bay

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	49	98,811	2,017
Feb-08	49	86,537	1,766
Mar-08	49	85,684	1,749
Apr-08	50	82,964	1,659
May-08	49	70,133	1,431
Jun-08	48	81,207	1,692
Jul-08	48	64,509	1,344
Aug-08	48	78,590	1,637
Sep-08	48	72,037	1,501
Oct-08	50	62,500	1,250
Nov-08	48	82,307	1,715
Dec-08	46	76,655	1,666
Jan-09	45	96,095	2,135
Feb-09	47	93,758	1,995
Mar-09	47	67,529	1,437
Apr-09	47	85,901	1,828
May-09	48	52,407	1,092
Jun-09	48	63,275	1,318
Jul-09	48	63,426	1,321
Aug-09	48	60,050	1,251
Sep-09	48	65,148	1,357
Oct-09	48	54,086	1,127
Nov-09	49	66,276	1,353
Dec-09	49	70,872	1,446
Jan-10	49	96,239	1,964
Feb-10	49	73,570	1,501
Mar-10	48	67,624	1,409
Apr-10	49	81,295	1,659
May-10	50	58,964	1,179
Jun-10	51	65,892	1,292
Jul-10	49	65,993	1,347
Aug-10	49	61,048	1,246
Sep-10	48	69,838	1,455
Oct-10	48	59,250	1,234
Nov-10	50	66,576	1,332
Dec-10	48	71,893	1,498
Jan-11	48	92,114	1,919
Feb-11	48	76,842	1,601
Mar-11	48	80,407	1,675
Apr-11	48	82,157	1,712
May-11	50	77,539	1,551
Jun-11	51	66,668	1,307
Jul-11	49	56,949	1,162
Aug-11	49	59,188	1,208
Sep-11	48	68,672	1,431
Nov-11	46	58,423	1,270
Nov-11	51	72,617	1,424
Dec-11	49	80,264	1,638
Jan-12	49	117,375	2,395
Feb-12	49	85,389	1,743
Mar-12	49	88,354	1,803
Apr-12	49	74,158	1,513
May-12	49	60,613	1,237
Jun-12	49	64,301	1,312
Jul-12	47	56,219	1,196
Aug-12	51	72,895	1,429
Sep-12	50	78,441	1,569
Oct-12	48	67,509	1,406
Nov-12	48	72,022	1,500
Dec-12	48	81,645	1,701

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Teslin

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	70	228,510	3,261
Feb-13	70	191,455	2,729
Mar-13	70	205,013	2,918
Apr-13	70	171,125	2,433
May-13	70	130,030	1,847
Jun-13	70	124,972	1,773
Jul-13	71	129,262	1,831
Aug-13	71	113,480	1,606
Sep-13	71	142,667	2,017
Oct-13	71	126,632	1,788
Nov-13	71	176,985	2,496
Dec-13	71	201,884	2,843
Jan-14	71	231,797	3,261
Feb-14	71	194,230	2,729
Mar-14	71	208,006	2,918
Apr-14	71	173,642	2,433
May-14	71	131,956	1,847
Jun-14	72	126,837	1,773
Jul-14	72	131,205	1,831
Aug-14	72	115,198	1,606
Sep-14	72	144,841	2,017
Oct-14	72	128,575	1,788
Nov-14	72	179,720	2,496
Dec-14	72	205,024	2,843
Jan-15	72	235,418	3,261
Feb-15	72	197,267	2,729
Mar-15	72	211,261	2,918
Apr-15	72	176,360	2,433
May-15	73	134,024	1,847
Jun-15	73	128,826	1,773
Jul-15	73	133,263	1,831
Aug-15	73	117,006	1,606
Sep-15	73	147,117	2,017
Oct-15	73	130,596	1,788
Nov-15	73	182,547	2,496
Dec-15	73	208,251	2,843

	Customers	Energy	Avg UPC
2013-F	71	1,942,015	27,530
2014-F	72	1,971,033	27,529
2015-F	73	2,001,936	27,529

Upper Liard

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	14	26,965	1,923
Feb-13	14	21,176	1,508
Mar-13	14	21,993	1,564
Apr-13	14	19,665	1,397
May-13	14	13,945	989
Jun-13	14	15,451	1,094
Jul-13	14	16,318	1,154
Aug-13	14	17,468	1,234
Sep-13	14	11,448	808
Oct-13	14	22,180	1,562
Nov-13	14	20,797	1,463
Dec-13	14	25,703	1,806
Jan-14	14	27,422	1,923
Feb-14	14	21,537	1,508
Mar-14	14	22,371	1,564
Apr-14	14	20,006	1,397
May-14	14	14,188	989
Jun-14	14	15,723	1,094
Jul-14	14	16,607	1,154
Aug-14	14	17,780	1,234
Sep-14	14	11,653	808
Oct-14	14	22,580	1,562
Nov-14	14	21,175	1,463
Dec-14	14	26,174	1,806
Jan-15	15	28,070	1,923
Feb-15	15	22,046	1,508
Mar-15	15	22,900	1,564
Apr-15	15	20,479	1,397
May-15	15	14,523	989
Jun-15	15	16,094	1,094
Jul-15	15	17,000	1,154
Aug-15	15	18,200	1,234
Sep-15	15	11,929	808
Oct-15	15	23,114	1,562
Nov-15	15	21,675	1,463
Dec-15	15	26,792	1,806

	Customers	Energy	Avg UPC
2013-F	14	233,109	16,500
2014-F	14	237,215	16,500
2015-F	15	242,820	16,500

Destruction Bay

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	48	100,570	2,093
Feb-13	48	77,695	1,615
Mar-13	48	78,460	1,629
Apr-13	48	78,501	1,628
May-13	48	63,833	1,322
Jun-13	48	63,010	1,304
Jul-13	48	59,754	1,235
Aug-13	48	62,694	1,294
Sep-13	48	71,999	1,485
Oct-13	49	63,284	1,304
Nov-13	49	68,943	1,419
Dec-13	49	78,442	1,612
Jan-14	49	101,950	2,093
Feb-14	49	78,769	1,615
Mar-14	49	79,553	1,629
Apr-14	49	79,602	1,628
May-14	49	64,735	1,322
Jun-14	49	63,907	1,304
Jul-14	49	60,610	1,235
Aug-14	49	63,599	1,294
Sep-14	49	73,046	1,485
Oct-14	49	64,211	1,304
Nov-14	49	69,960	1,419
Dec-14	49	79,606	1,612
Jan-15	49	103,541	2,093
Feb-15	50	79,999	1,615
Mar-15	50	80,796	1,629
Apr-15	50	80,847	1,628
May-15	50	65,748	1,322
Jun-15	50	64,908	1,304
Jul-15	50	61,560	1,235
Aug-15	50	64,596	1,294
Sep-15	50	74,192	1,485
Oct-15	50	65,219	1,304
Nov-15	50	71,059	1,419
Dec-15	50	80,858	1,612

	Customers	Energy	Avg UPC
2013-F	48	867,184	17,934
2014-F	49	879,549	17,934
2015-F	50	893,324	17,933

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Beaver Creek

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-08	44	89,358	2,031
Feb-08	44	133,371	3,031
Mar-08	44	38,006	864
Apr-08	52	79,993	1,538
May-08	53	118,707	2,240
Jun-08	53	79,837	1,506
Jul-08	51	114,280	2,241
Aug-08	51	132,679	2,602
Sep-08	49	88,448	1,805
Oct-08	48	68,743	1,432
Nov-08	41	81,156	1,979
Dec-08	41	82,977	2,024
Jan-09	42	102,810	2,448
Feb-09	41	86,079	2,099
Mar-09	42	84,699	2,017
Apr-09	45	80,255	1,783
May-09	51	77,033	1,510
Jun-09	51	93,100	1,825
Jul-09	51	129,021	2,530
Aug-09	51	106,975	2,098
Sep-09	51	103,498	2,029
Oct-09	50	111,981	2,240
Nov-09	41	38,788	946
Dec-09	41	77,194	1,883
Jan-10	39	99,620	2,554
Feb-10	39	82,939	2,127
Mar-10	39	78,339	2,009
Apr-10	43	74,945	1,743
May-10	49	88,043	1,797
Jun-10	51	107,992	2,117
Jul-10	53	128,036	2,416
Aug-10	53	125,452	2,367
Sep-10	53	92,687	1,749
Oct-10	52	94,315	1,814
Nov-10	45	81,812	1,818
Dec-10	41	75,385	1,839
Jan-11	41	110,795	2,702
Feb-11	41	80,033	1,952
Mar-11	41	91,959	2,243
Apr-11	52	85,935	1,653
May-11	53	123,375	2,328
Jun-11	53	100,289	1,892
Jul-11	52	115,620	2,223
Aug-11	54	127,427	2,360
Sep-11	54	113,926	2,110
Nov-11	50	90,446	1,809
Nov-11	44	78,777	1,790
Dec-11	41	86,463	2,109
Jan-12	39	90,079	2,310
Feb-12	39	76,311	1,957
Mar-12	39	78,695	2,018
Apr-12	50	72,969	1,459
May-12	50	78,673	1,573
Jun-12	50	117,501	2,350
Jul-12	50	103,170	2,063
Aug-12	50	115,724	2,314
Sep-12	50	86,264	1,725
Oct-12	50	78,314	1,566
Nov-12	43	83,120	1,933
Dec-12	36	73,580	2,044

Watson Lake **BASE (Before Large Adds)**

Base Commercial monthly	Customers	Energy (kWh)	Actual UPC (kWh)
Jan-08	166	572,441	3,448
Feb-08	165	590,669	3,580
Mar-08	165	544,032	3,297
Apr-08	166	502,010	3,024
May-08	175	491,312	2,807
Jun-08	182	469,175	2,578
Jul-08	180	501,315	2,785
Aug-08	181	522,406	2,886
Sep-08	188	437,685	2,328
Oct-08	168	434,163	2,584
Nov-08	163	532,668	3,268
Dec-08	165	529,892	3,211
Jan-09	165	612,999	3,715
Feb-09	167	544,359	3,260
Mar-09	163	518,737	3,182
Apr-09	162	496,967	3,068
May-09	169	467,605	2,767
Jun-09	176	445,940	2,534
Jul-09	177	494,796	2,795
Aug-09	175	464,386	2,654
Sep-09	177	441,280	2,493
Nov-09	167	500,060	2,994
Nov-09	164	635,272	3,874
Dec-09	166	446,774	2,691
Jan-10	159	618,993	3,893
Feb-10	161	590,130	3,665
Mar-10	156	522,517	3,349
Apr-10	165	533,742	3,235
May-10	178	441,090	2,478
Jun-10	185	439,015	2,373
Jul-10	184	484,601	2,634
Aug-10	184	455,164	2,474
Sep-10	157	401,724	2,559
Oct-10	175	545,857	3,119
Nov-10	174	524,193	3,013
Dec-10	171	564,653	3,302
Jan-11	171	655,153	3,831
Feb-11	171	538,445	3,149
Mar-11	171	601,947	3,520
Apr-11	170	507,810	2,987
May-11	181	481,162	2,658
Jun-11	188	460,157	2,448
Jul-11	186	444,037	2,387
Aug-11	190	366,835	1,931
Sep-11	185	457,783	2,475
Nov-11	183	485,944	2,655
Nov-11	178	551,841	3,100
Dec-11	176	593,611	3,373
Jan-12	176	721,619	4,100
Feb-12	174	584,459	3,359
Mar-12	174	618,441	3,554
Apr-12	172	543,793	3,162
May-12	178	525,476	2,952
Jun-12	185	515,897	2,789
Jul-12	186	450,262	2,421
Aug-12	183	492,001	2,689
Sep-12	186	568,132	3,054
Oct-12	179	327,900	1,832
Nov-12	173	611,768	3,536
Dec-12	169	643,981	3,811

Old Crow

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-08	36	67,068	1,863
Feb-08	36	82,504	2,292
Mar-08	36	67,205	1,867
Apr-08	36	61,010	1,695
May-08	36	64,410	1,789
Jun-08	38	65,153	1,715
Jul-08	39	46,313	1,188
Aug-08	38	63,222	1,664
Sep-08	38	50,827	1,338
Oct-08	36	46,442	1,290
Nov-08	36	77,581	2,155
Dec-08	36	70,871	1,969
Jan-09	35	85,987	2,457
Feb-09	35	63,846	1,824
Mar-09	36	77,262	2,146
Apr-09	36	74,060	2,057
May-09	37	69,284	1,873
Jun-09	36	52,610	1,461
Jul-09	36	66,046	1,835
Aug-09	35	45,682	1,305
Sep-09	35	44,662	1,276
Oct-09	35	66,900	1,911
Nov-09	34	59,153	1,740
Dec-09	35	69,048	1,973
Jan-10	35	82,489	2,357
Feb-10	35	64,923	1,855
Mar-10	35	65,174	1,862
Apr-10	35	80,462	2,299
May-10	35	53,747	1,536
Jun-10	35	54,364	1,553
Jul-10	35	47,590	1,360
Aug-10	39	46,323	1,188
Sep-10	40	47,352	1,184
Oct-10	40	59,598	1,490
Nov-10	40	66,045	1,651
Dec-10	39	66,299	1,700
Jan-11	40	87,427	2,186
Feb-11	40	79,874	1,997
Mar-11	40	73,122	1,828
Apr-11	40	73,497	1,837
May-11	40	72,699	1,817
Jun-11	40	62,070	1,552
Jul-11	40	61,581	1,540
Aug-11	40	55,150	1,379
Sep-11	40	61,418	1,535
Nov-11	40	59,221	1,481
Nov-11	40	68,823	1,721
Dec-11	40	82,704	2,068
Jan-12	40	81,822	2,046
Feb-12	40	73,746	1,844
Mar-12	40	96,431	2,411
Apr-12	40	80,562	2,014
May-12	40	65,105	1,628
Jun-12	41	74,146	1,808
Jul-12	41	52,307	1,276
Aug-12	41	71,273	1,738
Sep-12	40	50,379	1,259
Oct-12	40	64,873	1,622
Nov-12	41	65,249	1,591
Dec-12	41	111,378	2,717

The Yukon Electrical Company Limited
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Beaver Creek

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	36	90,925	2,522
Feb-13	36	72,628	2,012
Mar-13	36	75,551	2,090
Apr-13	36	58,587	1,618
May-13	36	68,858	1,899
Jun-13	36	76,962	2,120
Jul-13	36	81,224	2,234
Aug-13	36	85,446	2,347
Sep-13	36	67,855	1,861
Oct-13	37	63,144	1,730
Nov-13	37	67,527	1,847
Dec-13	37	73,111	1,997
Jan-14	37	92,471	2,522
Feb-14	37	73,873	2,012
Mar-14	37	76,855	2,090
Apr-14	37	59,605	1,618
May-14	37	70,064	1,899
Jun-14	37	78,318	2,120
Jul-14	37	82,666	2,234
Aug-14	37	86,974	2,347
Sep-14	37	69,076	1,861
Oct-14	37	64,288	1,730
Nov-14	37	68,758	1,847
Dec-14	37	74,453	1,997
Jan-15	37	94,170	2,522
Feb-15	37	75,257	2,012
Mar-15	37	78,292	2,090
Apr-15	38	60,718	1,618
May-15	38	71,370	1,899
Jun-15	38	79,777	2,120
Jul-15	38	84,203	2,234
Aug-15	38	88,588	2,347
Sep-15	38	70,356	1,861
Oct-15	38	65,478	1,730
Nov-15	38	70,029	1,847
Dec-15	38	75,827	1,997

	Customers	Energy	Avg UPC
2013-F	36	881,817	24,273
2014-F	37	897,400	24,272
2015-F	38	914,066	24,272

Watson Lake **BASE (Before Large Adds)**

Base Commercial monthly	Customers	Energy (kWh)	Actual UPC (kWh)
Jan-13	173	682,658	3,941
Feb-13	173	586,652	3,391
Mar-13	173	601,111	3,475
Apr-13	173	541,115	3,128
May-13	173	466,437	2,696
Jun-13	173	438,805	2,536
Jul-13	173	429,142	2,481
Aug-13	173	409,027	2,364
Sep-13	173	466,392	2,696
Oct-13	173	438,639	2,535
Nov-13	173	556,429	3,216
Dec-13	173	604,658	3,495
Jan-14	173	682,740	3,941
Feb-14	173	588,138	3,391
Mar-14	174	603,395	3,475
Apr-14	174	543,857	3,128
May-14	174	469,390	2,696
Jun-14	174	442,139	2,536
Jul-14	175	432,946	2,481
Aug-14	175	413,171	2,364
Sep-14	175	471,708	2,696
Oct-14	175	444,194	2,535
Nov-14	175	564,181	3,216
Dec-14	176	613,847	3,495
Jan-15	176	692,466	3,941
Feb-15	176	597,266	3,391
Mar-15	176	612,748	3,475
Apr-15	177	552,276	3,128
May-15	177	476,648	2,696
Jun-15	177	448,967	2,536
Jul-15	177	439,623	2,481
Aug-15	177	419,536	2,364
Sep-15	178	478,965	2,696
Oct-15	178	451,019	2,535
Nov-15	178	572,839	3,216
Dec-15	178	623,255	3,495

	Customers (ann	Fcst Energy (kW	Avg UPC
2013-F	173	6,221,065	35,956
2014-F	174	6,269,708	35,945
2015-F	177	6,365,608	35,944

Old Crow

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-13	41	90,135	2,196
Feb-13	41	78,008	1,898
Mar-13	41	83,654	2,034
Apr-13	41	84,424	2,050
May-13	41	68,443	1,660
Jun-13	41	67,592	1,638
Jul-13	41	57,497	1,392
Aug-13	41	59,350	1,435
Sep-13	41	54,913	1,326
Oct-13	41	63,450	1,531
Nov-13	41	68,648	1,654
Dec-13	42	89,782	2,161
Jan-14	42	91,331	2,196
Feb-14	42	79,051	1,898
Mar-14	42	84,780	2,034
Apr-14	42	85,569	2,050
May-14	42	69,378	1,660
Jun-14	42	68,523	1,638
Jul-14	42	58,294	1,392
Aug-14	42	60,178	1,435
Sep-14	42	55,685	1,326
Oct-14	42	64,348	1,531
Nov-14	42	69,627	1,654
Dec-14	42	91,071	2,161
Jan-15	42	92,657	2,196
Feb-15	42	80,210	1,898
Mar-15	42	86,022	2,034
Apr-15	42	86,821	2,050
May-15	42	70,392	1,660
Jun-15	42	69,523	1,638
Jul-15	42	59,143	1,392
Aug-15	43	61,054	1,435
Sep-15	43	56,495	1,326
Oct-15	43	65,283	1,531
Nov-15	43	70,637	1,654
Dec-15	43	92,391	2,161

	Customers	Energy	Avg UPC
2013-F	41	865,896	20,970
2014-F	42	877,835	20,969
2015-F	42	890,628	20,969

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Keno City

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	11	19,277	1,752
Feb-08	11	19,144	1,740
Mar-08	11	14,851	1,350
Apr-08	11	9,727	884
May-08	11	5,882	535
Jun-08	11	4,866	442
Jul-08	11	5,426	493
Aug-08	12	6,258	522
Sep-08	11	5,385	490
Oct-08	11	4,558	414
Nov-08	11	7,196	654
Dec-08	11	7,448	677
Jan-09	12	14,606	1,217
Feb-09	11	9,932	903
Mar-09	12	11,109	926
Apr-09	12	13,738	1,145
May-09	12	10,971	914
Jun-09	12	7,822	652
Jul-09	12	3,779	315
Aug-09	12	6,962	580
Sep-09	12	6,283	524
Oct-09	12	6,629	552
Nov-09	12	8,182	682
Dec-09	12	7,687	641
Jan-10	12	9,754	813
Feb-10	12	7,471	623
Mar-10	12	21,058	1,755
Apr-10	12	13,505	1,125
May-10	12	4,195	350
Jun-10	12	6,250	521
Jul-10	12	6,012	501
Aug-10	12	5,785	482
Sep-10	12	7,396	616
Oct-10	12	6,470	539
Nov-10	12	8,609	717
Dec-10	12	9,265	772
Jan-11	12	12,956	1,080
Feb-11	12	10,034	836
Mar-11	12	10,436	870
Apr-11	12	14,435	1,203
May-11	12	14,749	1,229
Jun-11	12	13,170	1,098
Jul-11	12	8,117	676
Aug-11	12	18,860	1,572
Sep-11	13	6,064	466
Nov-11	13	21,125	1,625
Nov-11	13	12,407	954
Dec-11	13	8,980	691
Jan-12	13	26,504	2,039
Feb-12	13	14,215	1,093
Mar-12	13	16,764	1,290
Apr-12	13	14,064	1,082
May-12	13	8,864	682
Jun-12	12	10,133	844
Jul-12	13	1,565	120
Aug-12	13	5,589	430
Sep-12	13	6,240	480
Oct-12	13	5,779	445
Nov-12	13	8,695	669
Dec-12	12	7,198	600

Stewart Crossing

Residential		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	15	36,240	2,416
Feb-08	14	44,894	3,207
Mar-08	14	28,784	2,056
Apr-08	14	16,642	1,189
May-08	15	26,842	1,789
Jun-08	14	19,982	1,427
Jul-08	14	13,104	936
Aug-08	14	19,541	1,396
Sep-08	15	15,633	1,042
Oct-08	14	20,461	1,462
Nov-08	14	25,597	1,828
Dec-08	13	26,703	2,054
Jan-09	11	36,807	3,346
Feb-09	14	36,052	2,575
Mar-09	14	27,967	1,998
Apr-09	15	25,031	1,669
May-09	15	19,941	1,329
Jun-09	14	16,842	1,203
Jul-09	13	18,775	1,444
Aug-09	14	17,707	1,265
Sep-09	14	16,260	1,161
Oct-09	15	19,057	1,270
Nov-09	15	20,545	1,370
Dec-09	15	24,637	1,642
Jan-10	10	25,358	2,536
Feb-10	13	26,715	2,055
Mar-10	13	23,031	1,772
Apr-10	13	22,521	1,732
May-10	11	17,272	1,570
Jun-10	13	14,021	1,079
Jul-10	12	14,894	1,241
Aug-10	12	15,434	1,286
Sep-10	11	15,516	1,411
Oct-10	14	33,981	2,427
Nov-10	16	27,780	1,736
Dec-10	16	33,270	2,079
Jan-11	16	37,114	2,320
Feb-11	16	32,155	2,010
Mar-11	16	35,227	2,202
Apr-11	15	23,627	1,575
May-11	14	21,575	1,541
Jun-11	14	16,071	1,148
Jul-11	15	16,872	1,125
Aug-11	16	18,348	1,147
Sep-11	16	20,879	1,305
Nov-11	16	18,378	1,149
Nov-11	16	24,599	1,537
Dec-11	13	26,291	2,022
Jan-12	14	34,076	2,434
Feb-12	14	26,323	1,880
Mar-12	13	40,429	3,110
Apr-12	13	9,050	696
May-12	9	14,773	1,641
Jun-12	13	22,093	1,699
Jul-12	13	16,595	1,277
Aug-12	13	14,994	1,153
Sep-12	13	13,689	1,053
Oct-12	13	17,805	1,370
Nov-12	13	30,666	2,359
Dec-12	13	23,891	1,838

Lower Post BC

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	12	20,658	1,722
Feb-08	12	20,430	1,703
Mar-08	12	19,032	1,586
Apr-08	12	19,402	1,617
May-08	12	16,739	1,395
Jun-08	11	9,833	894
Jul-08	13	9,117	701
Aug-08	13	8,646	665
Sep-08	15	10,710	714
Oct-08	13	12,541	965
Nov-08	13	16,435	1,264
Dec-08	13	20,043	1,542
Jan-09	13	24,397	1,877
Feb-09	12	19,373	1,614
Mar-09	13	20,139	1,549
Apr-09	13	18,011	1,385
May-09	13	13,818	1,063
Jun-09	13	12,242	942
Jul-09	13	12,620	971
Aug-09	13	10,974	844
Sep-09	14	14,572	1,041
Oct-09	14	15,466	1,105
Nov-09	15	20,437	1,362
Dec-09	15	26,563	1,771
Jan-10	15	32,126	2,142
Feb-10	14	24,626	1,759
Mar-10	14	23,598	1,686
Apr-10	15	22,159	1,477
May-10	15	14,719	981
Jun-10	15	13,642	909
Jul-10	15	12,079	805
Aug-10	15	10,519	701
Sep-10	13	9,895	761
Oct-10	11	10,514	956
Nov-10	14	30,914	2,208
Dec-10	13	24,941	1,919
Jan-11	13	25,325	1,948
Feb-11	12	18,667	1,556
Mar-11	12	23,229	1,936
Apr-11	12	16,035	1,336
May-11	12	12,800	1,067
Jun-11	12	14,218	1,185
Jul-11	12	9,863	822
Aug-11	12	11,714	976
Sep-11	13	14,390	1,107
Nov-11	13	17,891	1,376
Nov-11	13	23,053	1,773
Dec-11	13	25,053	1,927
Jan-12	13	31,371	2,413
Feb-12	13	26,952	2,073
Mar-12	14	26,567	1,898
Apr-12	14	23,101	1,650
May-12	14	19,762	1,412
Jun-12	14	18,378	1,313
Jul-12	14	16,520	1,180
Aug-12	14	16,064	1,147
Sep-12	14	15,662	1,119
Oct-12	14	20,696	1,478
Nov-12	14	22,725	1,623
Dec-12	14	30,647	2,189

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Keno City

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	12	15,744	1,310
Feb-13	12	10,233	851
Mar-13	12	15,712	1,305
Apr-13	12	13,706	1,137
May-13	12	9,096	754
Jun-13	12	9,921	821
Jul-13	12	5,234	433
Aug-13	12	10,029	828
Sep-13	12	6,318	521
Oct-13	12	10,559	870
Nov-13	12	9,485	780
Dec-13	12	8,368	688
Jan-14	12	15,970	1,310
Feb-14	12	10,381	851
Mar-14	12	15,941	1,305
Apr-14	12	13,907	1,137
May-14	12	9,230	754
Jun-14	12	10,069	821
Jul-14	12	5,313	433
Aug-14	12	10,181	828
Sep-14	12	6,414	521
Oct-14	12	10,720	870
Nov-14	12	9,631	780
Dec-14	12	8,498	688
Jan-15	12	16,272	1,310
Feb-15	12	10,546	851
Mar-15	12	16,193	1,305
Apr-15	12	14,127	1,137
May-15	12	9,376	754
Jun-15	12	10,228	821
Jul-15	12	5,397	433
Aug-15	12	10,341	828
Sep-15	13	6,515	521
Oct-15	13	10,889	870
Nov-15	13	9,782	780
Dec-15	13	8,631	688

	Customers	Energy	Avg UPC
2013-F	12	124,405	10,288
2014-F	12	126,255	10,287
2015-F	12	128,296	10,288

Stewart Crossing

Residential		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	13	31,622	2,430
Feb-13	13	25,818	1,982
Mar-13	13	30,795	2,361
Apr-13	13	17,425	1,335
May-13	13	20,708	1,584
Jun-13	13	17,124	1,309
Jul-13	13	15,905	1,214
Aug-13	13	15,677	1,195
Sep-13	13	16,491	1,256
Oct-13	13	21,665	1,648
Nov-13	13	24,702	1,878
Dec-13	13	26,077	1,980
Jan-14	13	32,041	2,430
Feb-14	13	26,163	1,982
Mar-14	13	31,209	2,361
Apr-14	13	17,662	1,335
May-14	13	20,991	1,584
Jun-14	13	17,360	1,309
Jul-14	13	16,126	1,214
Aug-14	13	15,896	1,195
Sep-14	13	16,723	1,256
Oct-14	13	21,972	1,648
Nov-14	13	25,054	1,878
Dec-14	13	26,451	1,980
Jan-15	13	32,602	2,430
Feb-15	13	26,546	1,982
Mar-15	13	31,666	2,361
Apr-15	13	17,920	1,335
May-15	13	21,297	1,584
Jun-15	13	17,613	1,309
Jul-15	13	16,361	1,214
Aug-15	13	16,127	1,195
Sep-15	14	16,966	1,256
Oct-15	14	22,291	1,648
Nov-15	14	25,418	1,878
Dec-15	14	26,834	1,980

	Customers	Energy	Avg UPC
2013-F	13	264,010	20,165
2014-F	13	267,646	20,164
2015-F	13	271,640	20,166

Lower Post BC

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	14	30,381	2,168
Feb-13	14	24,872	1,796
Mar-13	14	26,098	1,840
Apr-13	14	21,107	1,488
May-13	14	16,359	1,153
Jun-13	14	16,111	1,136
Jul-13	14	13,274	936
Aug-13	14	13,358	942
Sep-13	14	14,124	996
Oct-13	14	18,018	1,270
Nov-13	14	26,503	1,868
Dec-13	14	28,537	2,012
Jan-14	14	30,788	2,168
Feb-14	14	25,539	1,796
Mar-14	14	26,192	1,840
Apr-14	14	21,209	1,488
May-14	14	16,458	1,153
Jun-14	14	16,228	1,136
Jul-14	14	13,387	936
Aug-14	14	13,487	942
Sep-14	14	14,277	996
Oct-14	14	18,236	1,270
Nov-14	14	26,855	1,868
Dec-14	14	28,951	2,012
Jan-15	14	31,321	2,168
Feb-15	14	25,918	1,796
Mar-15	14	26,580	1,840
Apr-15	14	21,523	1,488
May-15	14	16,701	1,153
Jun-15	14	16,467	1,136
Jul-15	15	13,584	936
Aug-15	15	13,686	942
Sep-15	15	14,487	996
Oct-15	15	18,503	1,270
Nov-15	15	27,249	1,868
Dec-15	15	29,375	2,012

	Customers	Energy	Avg UPC
2013-F	14	248,741	17,587
2014-F	14	251,608	17,598
2015-F	15	255,393	17,600

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Ross River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	46	114,224	2,483
Feb-08	46	146,930	3,194
Mar-08	43	104,852	2,438
Apr-08	46	97,281	2,115
May-08	46	106,530	2,316
Jun-08	46	80,827	1,757
Jul-08	46	71,189	1,548
Aug-08	46	83,888	1,824
Sep-08	46	84,846	1,844
Oct-08	46	93,934	2,042
Nov-08	46	96,656	2,101
Dec-08	46	125,362	2,725
Jan-09	45	137,387	3,053
Feb-09	46	94,202	2,048
Mar-09	46	119,217	2,592
Apr-09	46	101,227	2,201
May-09	46	90,002	1,957
Jun-09	46	77,208	1,678
Jul-09	46	75,007	1,631
Aug-09	46	89,016	1,935
Sep-09	46	50,462	1,097
Oct-09	46	100,197	2,178
Nov-09	46	88,146	1,916
Dec-09	46	120,466	2,619
Jan-10	46	137,669	2,993
Feb-10	47	113,244	2,409
Mar-10	46	115,089	2,502
Apr-10	45	112,834	2,507
May-10	45	79,657	1,770
Jun-10	45	85,169	1,893
Jul-10	45	86,646	1,925
Aug-10	46	85,599	1,861
Sep-10	46	82,613	1,796
Oct-10	46	89,508	1,946
Nov-10	46	96,741	2,103
Dec-10	46	123,366	2,682
Jan-11	46	136,826	2,974
Feb-11	45	114,211	2,538
Mar-11	46	107,244	2,331
Apr-11	45	109,005	2,422
May-11	44	78,303	1,780
Jun-11	44	73,675	1,674
Jul-11	43	78,956	1,836
Aug-11	43	74,081	1,723
Sep-11	45	80,053	1,779
Nov-11	46	80,189	1,743
Nov-11	47	89,330	1,901
Dec-11	47	93,650	1,993
Jan-12	47	175,496	3,734
Feb-12	49	132,363	2,701
Mar-12	49	145,810	2,976
Apr-12	47	101,554	2,161
May-12	50	100,742	2,015
Jun-12	50	103,358	2,067
Jul-12	51	90,261	1,770
Aug-12	50	97,662	1,953
Sep-12	50	86,122	1,722
Oct-12	48	98,996	2,062
Nov-12	48	124,903	2,602
Dec-12	47	119,613	2,545

Pelly Crossing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	29	90,812	3,131
Feb-08	29	108,137	3,729
Mar-08	29	81,804	2,821
Apr-08	29	59,285	2,044
May-08	30	75,053	2,502
Jun-08	29	58,602	2,021
Jul-08	30	44,911	1,497
Aug-08	30	60,469	2,016
Sep-08	30	65,290	2,176
Oct-08	30	89,703	2,990
Nov-08	30	81,690	2,723
Dec-08	30	73,897	2,463
Jan-09	29	85,513	2,949
Feb-09	29	65,603	2,262
Mar-09	29	111,365	3,840
Apr-09	28	82,326	2,940
May-09	30	131,105	4,370
Jun-09	30	68,339	2,278
Jul-09	31	74,106	2,391
Aug-09	32	60,731	1,898
Sep-09	31	77,585	2,503
Oct-09	30	75,941	2,531
Nov-09	31	90,630	2,924
Dec-09	31	82,561	2,663
Jan-10	29	105,601	3,641
Feb-10	31	87,952	2,837
Mar-10	30	84,203	2,807
Apr-10	31	90,283	2,912
May-10	30	71,896	2,397
Jun-10	31	72,670	2,344
Jul-10	30	73,172	2,439
Aug-10	32	70,189	2,193
Sep-10	26	65,567	2,522
Oct-10	31	96,555	3,115
Nov-10	31	138,307	4,462
Dec-10	30	62,920	2,097
Jan-11	29	129,575	4,468
Feb-11	29	100,874	3,478
Mar-11	28	102,885	3,674
Apr-11	29	92,837	3,201
May-11	30	104,604	3,487
Jun-11	30	69,469	2,316
Jul-11	29	77,856	2,685
Aug-11	30	70,242	2,341
Sep-11	29	82,164	2,833
Nov-11	29	72,958	2,516
Nov-11	27	89,845	3,328
Dec-11	28	82,380	2,942
Jan-12	29	122,556	4,226
Feb-12	27	85,292	3,159
Mar-12	28	101,698	3,632
Apr-12	28	79,907	2,854
May-12	29	75,037	2,587
Jun-12	26	74,738	2,875
Jul-12	29	62,125	2,142
Aug-12	29	70,267	2,423
Sep-12	29	68,366	2,357
Oct-12	28	76,625	2,737
Nov-12	28	119,676	4,274
Dec-12	28	88,012	3,143

Swift River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	13	26,310	2,024
Feb-08	13	21,945	1,688
Mar-08	13	18,796	1,446
Apr-08	13	20,063	1,543
May-08	13	15,812	1,216
Jun-08	13	12,746	980
Jul-08	13	12,899	992
Aug-08	13	13,740	1,057
Sep-08	13	12,483	960
Oct-08	13	13,163	1,013
Nov-08	13	21,162	1,628
Dec-08	13	20,924	1,610
Jan-09	12	23,479	1,957
Feb-09	13	21,573	1,659
Mar-09	13	24,221	1,863
Apr-09	13	17,441	1,342
May-09	13	14,149	1,088
Jun-09	13	11,604	893
Jul-09	12	12,459	1,038
Aug-09	13	12,475	960
Sep-09	13	12,245	942
Oct-09	13	11,214	863
Nov-09	13	18,184	1,399
Dec-09	13	16,676	1,283
Jan-10	12	20,342	1,695
Feb-10	12	16,017	1,335
Mar-10	14	15,800	1,129
Apr-10	12	11,941	995
May-10	14	13,788	985
Jun-10	15	5,934	396
Jul-10	15	6,425	428
Aug-10	14	8,304	593
Sep-10	11	9,447	859
Oct-10	13	10,679	821
Nov-10	13	18,199	1,400
Dec-10	14	18,494	1,321
Jan-11	13	21,181	1,629
Feb-11	14	17,628	1,259
Mar-11	14	20,929	1,495
Apr-11	14	15,964	1,140
May-11	14	10,835	774
Jun-11	14	9,352	668
Jul-11	14	8,736	624
Aug-11	14	10,780	770
Sep-11	14	9,790	699
Nov-11	14	14,352	1,025
Nov-11	14	16,597	1,186
Dec-11	14	17,469	1,248
Jan-12	14	23,487	1,678
Feb-12	14	17,642	1,260
Mar-12	14	17,026	1,216
Apr-12	14	16,382	1,170
May-12	14	12,813	915
Jun-12	14	12,781	913
Jul-12	14	10,368	741
Aug-12	14	12,957	926
Sep-12	14	10,066	719
Oct-12	14	14,818	1,058
Nov-12	14	17,318	1,237
Dec-12	14	18,437	1,317

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Ross River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	47	152,162	3,234
Feb-13	47	120,108	2,550
Mar-13	47	122,767	2,603
Apr-13	47	111,599	2,363
May-13	47	87,684	1,855
Jun-13	47	88,883	1,878
Jul-13	47	87,363	1,844
Aug-13	47	87,549	1,846
Sep-13	47	83,857	1,766
Oct-13	48	91,151	1,917
Nov-13	48	104,811	2,202
Dec-13	48	114,676	2,406
Jan-14	48	154,294	3,234
Feb-14	48	121,804	2,550
Mar-14	48	124,513	2,603
Apr-14	48	113,198	2,363
May-14	48	88,950	1,855
Jun-14	48	90,176	1,878
Jul-14	48	88,642	1,844
Aug-14	48	88,840	1,846
Sep-14	48	85,102	1,766
Oct-14	48	92,514	1,917
Nov-14	48	106,389	2,202
Dec-14	48	116,415	2,406
Jan-15	48	156,621	3,234
Feb-15	49	123,690	2,550
Mar-15	49	126,438	2,603
Apr-15	49	114,946	2,363
May-15	49	90,321	1,855
Jun-15	49	91,565	1,878
Jul-15	49	90,006	1,844
Aug-15	49	90,205	1,846
Sep-15	49	86,408	1,766
Oct-15	49	93,932	1,917
Nov-15	49	108,018	2,202
Dec-15	49	118,195	2,406

	Customers	Energy	Avg UPC
2013-F	47	1,252,611	26,452
2014-F	48	1,270,836	26,451
2015-F	49	1,290,344	26,451

Pelly Crossing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	28	115,261	4,112
Feb-13	28	88,627	3,158
Mar-13	28	94,708	3,371
Apr-13	28	84,071	2,989
May-13	28	79,504	2,824
Jun-13	28	70,793	2,511
Jul-13	28	68,347	2,422
Aug-13	28	65,521	2,319
Sep-13	28	72,709	2,571
Oct-13	28	78,967	2,789
Nov-13	28	113,977	4,021
Dec-13	28	77,399	2,728
Jan-14	28	116,821	4,112
Feb-14	28	89,836	3,158
Mar-14	28	96,009	3,371
Apr-14	29	85,235	2,989
May-14	29	80,612	2,824
Jun-14	29	71,788	2,511
Jul-14	29	69,315	2,422
Aug-14	29	66,455	2,319
Sep-14	29	73,752	2,571
Oct-14	29	80,108	2,789
Nov-14	29	115,636	4,021
Dec-14	29	78,533	2,728
Jan-15	29	118,624	4,112
Feb-15	29	91,180	3,158
Mar-15	29	97,445	3,371
Apr-15	29	86,508	2,989
May-15	29	81,814	2,824
Jun-15	29	72,857	2,511
Jul-15	29	70,346	2,422
Aug-15	29	67,442	2,319
Sep-15	29	74,847	2,571
Oct-15	29	81,296	2,789
Nov-15	29	117,347	4,021
Dec-15	29	79,694	2,728

	Customers	Energy	Avg UPC
2013-F	28	1,009,884	35,807
2014-F	29	1,024,101	35,806
2015-F	29	1,039,400	35,807

Swift River

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	14	23,369	1,667
Feb-13	14	18,025	1,285
Mar-13	14	17,978	1,280
Apr-13	14	15,494	1,102
May-13	14	12,548	891
Jun-13	14	9,285	659
Jul-13	14	8,432	598
Aug-13	14	10,775	763
Sep-13	14	10,732	759
Oct-13	14	13,707	968
Nov-13	14	18,055	1,274
Dec-13	14	18,375	1,295
Jan-14	14	23,682	1,667
Feb-14	14	18,269	1,285
Mar-14	14	18,222	1,280
Apr-14	14	15,706	1,102
May-14	14	12,721	891
Jun-14	14	9,414	659
Jul-14	14	8,550	598
Aug-14	14	10,927	763
Sep-14	14	10,885	759
Oct-14	14	13,903	968
Nov-14	14	18,316	1,274
Dec-14	14	18,641	1,295
Jan-15	14	24,092	1,667
Feb-15	14	18,539	1,285
Mar-15	14	18,492	1,280
Apr-15	14	15,939	1,102
May-15	14	12,909	891
Jun-15	14	9,553	659
Jul-15	15	8,676	598
Aug-15	15	11,088	763
Sep-15	15	11,045	759
Oct-15	15	14,107	968
Nov-15	15	18,584	1,274
Dec-15	15	18,914	1,295

	Customers	Energy	Avg UPC
2013-F	14	176,776	12,537
2014-F	14	179,237	12,536
2015-F	15	181,938	12,538

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Tagish

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	22	25,254	1,148
Feb-08	22	36,477	1,658
Mar-08	22	24,544	1,116
Apr-08	25	26,422	1,057
May-08	20	18,392	920
Jun-08	20	11,850	593
Jul-08	21	13,042	621
Aug-08	22	16,086	731
Sep-08	23	13,294	578
Oct-08	23	19,118	831
Nov-08	23	23,771	1,034
Dec-08	22	23,705	1,078
Jan-09	19	21,201	1,116
Feb-09	23	29,194	1,269
Mar-09	23	23,077	1,003
Apr-09	23	24,157	1,050
May-09	24	19,435	810
Jun-09	22	15,296	695
Jul-09	22	17,049	775
Aug-09	22	16,109	732
Sep-09	22	15,861	721
Oct-09	25	18,091	724
Nov-09	23	20,494	891
Dec-09	24	25,196	1,050
Jan-10	24	31,495	1,312
Feb-10	23	20,170	877
Mar-10	24	28,603	1,192
Apr-10	23	25,020	1,088
May-10	21	19,528	930
Jun-10	23	17,417	757
Jul-10	22	15,016	683
Aug-10	22	13,970	635
Sep-10	19	11,790	621
Oct-10	21	17,435	830
Nov-10	24	21,669	903
Dec-10	23	23,950	1,041
Jan-11	23	30,030	1,306
Feb-11	24	25,614	1,067
Mar-11	24	25,395	1,058
Apr-11	25	31,050	1,242
May-11	26	33,448	1,286
Jun-11	26	18,024	693
Jul-11	23	13,595	591
Aug-11	23	13,512	587
Sep-11	23	12,778	556
Nov-11	25	15,944	638
Nov-11	24	16,744	698
Dec-11	24	26,166	1,090
Jan-12	23	32,209	1,400
Feb-12	23	16,604	722
Mar-12	23	25,466	1,107
Apr-12	19	16,598	874
May-12	23	15,970	694
Jun-12	23	15,204	661
Jul-12	24	18,891	787
Aug-12	24	16,045	669
Sep-12	24	13,882	578
Oct-12	24	15,813	659
Nov-12	24	22,753	948
Dec-12	24	22,475	936

Marsh Lake

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	25	31,098	1,244
Feb-08	25	31,587	1,263
Mar-08	25	28,784	1,151
Apr-08	25	27,459	1,098
May-08	25	19,607	784
Jun-08	23	19,010	827
Jul-08	22	16,652	757
Aug-08	22	20,030	910
Sep-08	24	17,252	719
Oct-08	24	19,263	803
Nov-08	24	28,419	1,184
Dec-08	23	32,895	1,430
Jan-09	24	33,441	1,393
Feb-09	24	27,733	1,156
Mar-09	21	34,092	1,623
Apr-09	23	11,189	486
May-09	24	17,663	736
Jun-09	22	15,389	700
Jul-09	21	16,891	804
Aug-09	21	15,895	757
Sep-09	21	17,977	856
Oct-09	22	17,834	811
Nov-09	24	22,189	925
Dec-09	23	27,937	1,215
Jan-10	24	27,159	1,132
Feb-10	24	21,898	912
Mar-10	24	23,726	989
Apr-10	24	21,966	915
May-10	24	20,304	846
Jun-10	23	15,146	659
Jul-10	23	21,412	931
Aug-10	21	19,031	906
Sep-10	15	9,032	602
Oct-10	21	34,961	1,665
Nov-10	22	28,599	1,300
Dec-10	23	32,912	1,431
Jan-11	23	39,956	1,737
Feb-11	23	28,861	1,255
Mar-11	22	35,924	1,633
Apr-11	20	32,403	1,620
May-11	22	22,563	1,026
Jun-11	22	21,583	981
Jul-11	21	17,059	812
Aug-11	22	18,617	846
Sep-11	21	19,857	946
Nov-11	23	21,173	921
Nov-11	23	27,688	1,204
Dec-11	23	36,375	1,582
Jan-12	23	34,562	1,503
Feb-12	23	36,303	1,578
Mar-12	23	30,477	1,325
Apr-12	23	27,482	1,195
May-12	23	29,931	1,301
Jun-12	23	21,150	920
Jul-12	24	20,492	854
Aug-12	24	23,435	976
Sep-12	24	21,046	877
Oct-12	24	24,365	1,015
Nov-12	25	35,412	1,416
Dec-12	25	39,253	1,570

Deep Creek

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-08	2	4,794	2,397
Feb-08	2	5,740	2,870
Mar-08	2	3,936	1,968
Apr-08	2	3,899	1,950
May-08	2	3,432	1,716
Jun-08	2	2,148	1,074
Jul-08	2	1,641	821
Aug-08	2	1,278	639
Sep-08	2	1,475	738
Oct-08	2	1,702	851
Nov-08	2	3,834	1,917
Dec-08	2	5,661	2,831
Jan-09	2	6,706	3,353
Feb-09	2	6,706	3,353
Mar-09	2	7,274	3,637
Apr-09	2	5,558	2,779
May-09	2	4,558	2,279
Jun-09	2	3,333	1,667
Jul-09	2	3,144	1,572
Aug-09	2	2,038	1,019
Sep-09	2	2,841	1,421
Oct-09	2	3,052	1,526
Nov-09	2	5,245	2,623
Dec-09	2	4,552	2,276
Jan-10	2	6,121	3,061
Feb-10	2	4,582	2,291
Mar-10	1	679	679
Apr-10	1	670	670
May-10	2	9,364	4,682
Jun-10	2	1,511	756
Jul-10	2	1,598	799
Aug-10	2	1,204	602
Sep-10	2	1,938	969
Oct-10	2	2,135	1,068
Nov-10	2	3,122	1,561
Dec-10	2	3,200	1,600
Jan-11	2	4,248	2,124
Feb-11	2	7,299	3,650
Mar-11	2	5,654	2,827
Apr-11	2	5,959	2,980
May-11	2	2,657	1,329
Jun-11	2	1,945	973
Jul-11	2	1,710	855
Aug-11	2	1,339	670
Sep-11	2	1,751	876
Nov-11	2	2,356	1,178
Nov-11	2	3,144	1,572
Dec-11	2	3,691	1,846
Jan-12	2	6,000	3,000
Feb-12	2	6,066	3,033
Mar-12	2	5,560	2,780
Apr-12	2	5,131	2,566
May-12	2	3,362	1,681
Jun-12	2	3,128	1,564
Jul-12	2	1,665	833
Aug-12	2	1,683	842
Sep-12	2	1,961	981
Oct-12	2	1,803	902
Nov-12	2	2,457	1,229
Dec-12	2	3,829	1,915

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Tagish

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	24	32,181	1,339
Feb-13	24	21,375	889
Mar-13	24	26,944	1,119
Apr-13	24	25,738	1,068
May-13	24	23,412	970
Jun-13	24	17,002	704
Jul-13	24	16,611	687
Aug-13	24	15,259	630
Sep-13	24	14,173	585
Oct-13	24	17,199	709
Nov-13	24	20,631	850
Dec-13	24	24,863	1,023
Jan-14	24	32,602	1,339
Feb-14	24	21,657	889
Mar-14	24	27,302	1,119
Apr-14	24	26,083	1,068
May-14	24	23,727	970
Jun-14	24	17,233	704
Jul-14	25	16,838	687
Aug-14	25	15,469	630
Sep-14	25	14,369	585
Oct-14	25	17,439	709
Nov-14	25	20,922	850
Dec-14	25	25,215	1,023
Jan-15	25	33,102	1,339
Feb-15	25	21,970	889
Mar-15	25	27,697	1,119
Apr-15	25	26,459	1,068
May-15	25	24,069	970
Jun-15	25	17,481	704
Jul-15	25	17,080	687
Aug-15	25	15,692	630
Sep-15	25	14,576	585
Oct-15	25	17,689	709
Nov-15	25	21,221	850
Dec-15	25	25,576	1,023

	Customers	Energy	Avg UPC
2013-F	24	255,389	10,567
2014-F	24	258,857	10,566
2015-F	25	262,612	10,567

Marsh Lake

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	25	36,468	1,457
Feb-13	25	31,279	1,249
Mar-13	25	32,992	1,316
Apr-13	25	31,216	1,243
May-13	25	26,580	1,058
Jun-13	25	21,461	853
Jul-13	25	21,802	866
Aug-13	25	22,932	910
Sep-13	25	20,396	808
Oct-13	25	30,320	1,200
Nov-13	25	33,047	1,307
Dec-13	25	38,670	1,528
Jan-14	25	36,931	1,457
Feb-14	25	31,680	1,249
Mar-14	25	33,418	1,316
Apr-14	25	31,622	1,243
May-14	25	26,928	1,058
Jun-14	25	21,744	853
Jul-14	26	22,092	866
Aug-14	26	23,239	910
Sep-14	26	20,671	808
Oct-14	26	30,732	1,200
Nov-14	26	33,499	1,307
Dec-14	26	39,203	1,528
Jan-15	26	37,481	1,457
Feb-15	26	32,126	1,249
Mar-15	26	33,887	1,316
Apr-15	26	32,066	1,243
May-15	26	27,306	1,058
Jun-15	26	22,048	853
Jul-15	26	22,401	866
Aug-15	26	23,564	910
Sep-15	26	20,960	808
Oct-15	26	31,160	1,200
Nov-15	26	33,965	1,307
Dec-15	26	39,748	1,528

	Customers	Energy	Avg UPC
2013-F	25	347,164	13,792
2014-F	26	351,759	13,792
2015-F	26	356,711	13,792

Deep Creek

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	2	5,462	2,728
Feb-13	2	5,996	2,991
Mar-13	2	4,205	2,095
Apr-13	2	4,162	2,072
May-13	2	5,156	2,564
Jun-13	2	2,209	1,097
Jul-13	2	1,671	829
Aug-13	2	1,421	704
Sep-13	2	1,902	942
Oct-13	2	2,121	1,049
Nov-13	2	2,943	1,454
Dec-13	2	3,621	1,787
Jan-14	2	5,536	2,728
Feb-14	2	6,077	2,991
Mar-14	2	4,262	2,095
Apr-14	2	4,219	2,072
May-14	2	5,227	2,564
Jun-14	2	2,240	1,097
Jul-14	2	1,694	829
Aug-14	2	1,441	704
Sep-14	2	1,929	942
Oct-14	2	2,152	1,049
Nov-14	2	2,986	1,454
Dec-14	2	3,673	1,787
Jan-15	2	5,766	2,728
Feb-15	2	6,167	2,991
Mar-15	2	4,325	2,095
Apr-15	2	4,281	2,072
May-15	2	5,304	2,564
Jun-15	2	2,273	1,097
Jul-15	2	1,719	829
Aug-15	2	1,462	704
Sep-15	2	1,957	942
Oct-15	2	2,183	1,049
Nov-15	2	3,029	1,454
Dec-15	2	3,727	1,787

	Customers	Energy	Avg UPC
2013-F	2	40,869	20,288
2014-F	2	41,435	20,286
2015-F	2	42,194	20,313

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Minto Landing

Commercial monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)
Jan-12	2	3,438	1,719
Feb-12	2	3,830	1,915
Mar-12	2	3,613	1,807
Apr-12	2	3,577	1,789
May-12	2	4,618	2,309
Jun-12	2	3,719	1,860
Jul-12	2	3,763	1,882
Aug-12	2	4,660	2,330
Sep-12	2	3,860	1,930
Oct-12	3	3,250	1,083
Nov-12	3	4,665	1,555
Dec-12	3	4,500	1,500

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Minto Landing

Commercial		Energy (kWh)	
monthly	Customers	(Billed)	UPC (kWh)
Jan-13	3	5,201	1,719
Feb-13	3	5,842	1,915
Mar-13	3	5,557	1,807
Apr-13	3	5,547	1,789
May-13	3	7,219	2,309
Jun-13	3	5,861	1,860
Jul-13	3	5,978	1,882
Aug-13	3	7,462	2,330
Sep-13	3	6,230	1,930
Oct-13	3	3,524	1,083
Nov-13	3	5,098	1,555
Dec-13	3	4,956	1,500
Jan-14	3	5,728	1,719
Feb-14	3	6,434	1,915
Mar-14	3	6,120	1,807
Apr-14	3	6,110	1,789
May-14	3	7,952	2,309
Jun-14	3	6,456	1,860
Jul-14	4	6,585	1,882
Aug-14	4	8,220	2,330
Sep-14	4	6,863	1,930
Oct-14	4	3,883	1,083
Nov-14	4	5,617	1,555
Dec-14	4	5,460	1,500
Jan-15	4	6,356	1,719
Feb-15	4	7,093	1,915
Mar-15	4	6,742	1,807
Apr-15	4	6,725	1,789
May-15	4	8,746	2,309
Jun-15	4	7,096	1,860
Jul-15	4	7,232	1,882
Aug-15	4	9,022	2,330
Sep-15	4	7,527	1,930
Oct-15	4	4,255	1,083
Nov-15	4	6,152	1,555
Dec-15	4	5,976	1,500

	Customers	Energy	Avg UPC
2013-F	3	68,476	21,638
2014-F	3	75,428	21,637
2015-F	4	82,922	21,641

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Table A: Billed to Earned Factor

Communities	Earned	Billed	Billed to Earmed
	2012	2012	Factor
1	2	3	4
Carmacks	2,488	2,445	1.017
Carcross	1,102	1,088	1.013
Haines Junction	3,822	3,768	1.014
Teslin	2,080	2,036	1.021
Upper Liard	300	293	1.024
Destruction Bay	935	919	1.018
Whitehorse	136,170	133,847	1.017
Beaver Creek	1,068	1,054	1.013
Watson Lake	6,713	6,604	1.017
Old Crow	903	887	1.017
Keno City	126	126	1.003
Stewart Crossing	270	264	1.021
Lower Post B.C.	274	268	1.019
Ross River	1,400	1,377	1.017
Pelly Crossing	1,046	1,024	1.021
Swift River	188	184	1.019
Tagish	237	232	1.021
Marsh Lake	351	344	1.020
Deep Creek	43	43	1.002
Minto Landing	48	47	1.018
TOTAL GENERAL SERVICE	159,562	156,851	

The Yukon Electrical Company Limited
Whitehorse Heating Degree Data

Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Commercial Regression Results

Commercial (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77977
R Square	0.60804
Adjusted R Square	0.60584
Standard Error	379.854
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*gnificance F*
Regression	1	4E+07	4E+07	276.129	4.8E-38
Residual	178	2.6E+07	144289		
Total	179	6.6E+07			

	Coefficients	*tandard Er*	*t Stat*	*P-value*	*.ower 95%*	*Jpper 95%*	*ower 95.0%*	*pper 95.0%*
Intercept	4662.8	55.0	84.8	0.0	4554.3	4771.2	4554.3	4771.2
WH-HDD	1.42567	0.08579	16.61713	0.00000	1.25636	1.59497	1.25636	1.59497

CW-YECL-4

Reference: Other Revenue, Application page 2-9.

In its Application, YECL states:

> Yukon Electrical's other revenues have been included with retail sales revenues as part of the revenue requirement. These amounts are detailed in Schedule 2.2. Reconnect, Joint Use and Services to Outside Parties revenues are forecast to increase in each year of the test period due to inflation. Other Revenues are forecast to decrease starting in 2014 due to a reduction in office rental income.

The City requires information to understand the decrease in 2014 rental income.

Request:

(a) Please fully explain why rental income is forecast to decrease in 2014.

(b) Please fully explain what steps YECL is taking to replace the reduction in rental income.

Response:

(a) The Yukon Government (Economic Development) is choosing to vacate the space they have been leasing on the upper floor of Yukon Electrical's downtown office building, resulting in less rental income. At the time the Application was filed, it was forecast that they would vacate at the end of 2013; however, Yukon Electrical has since learned that they plan to vacate the space at the end of August 2013.

(b) Yukon Electrical is not planning to replace the rental income as the space is needed for Yukon Electrical employees due to the growth in complement over the past few years.

CW-YECL-5

Reference: Purchased Power, Application, Pages 3-2 and 3-3.

In its Application, YECL states:

> The energy component of the purchase power cost is determined by applying Yukon Energy's wholesale rate to the total forecast energy (kWh) purchases. Total forecast purchases are determined by applying a forecast line loss percentage to Yukon Electrical's sales load forecast that was discussed in Section 2. Overall, line losses are determined by using a five-year historical average of 6.2%. This is consistent with the approach approved in Board Order 2009-2.

The City requires information to understand the level of losses, and the efforts YECL has undertaken to mitigate losses.

Request:

(a) Please fully explain the steps that YECL could take to reduce losses.

(b) Please fully explain which of the steps, identified in response to (a) above, YECL has implemented, and which it has not implemented, including the reasons.

(c) Please fully explain what additional steps that YECL could undertake to reduce losses, and the costs of implementation.

Response:

(a) To reduce line losses, a utility such as Yukon Electrical can utilize a larger conductor size to lower resistance in the distribution system, use higher system voltages to reduce current loading, and work to lower electrical equipment impedance in the distribution system.

(b) Steps Yukon Electrical has implemented to reduce losses:

- Yukon Electrical installs maximum-sized conductors based on engineering standards for all new extensions and system improvement distribution lines. This inherently improves line losses when old distribution lines are upgraded with larger conductors.

- Yukon Electrical has converted various sections of the distribution system to higher voltages, such as the Hillcrest subdivision. Line losses are reduced on system loading when the distribution voltages are increased.

- Yukon Electrical evaluates the life cycle costs of transformers and selects a supplier based on the lowest life time cost. The large power transformers for Shipyards and Whistlebend substations were tendered, designed and built to ensure impedances were matched to reduce internal losses to a minimum.

- All new revenue meters purchased are electronic meters, which have lower internal losses than mechanical meters.

- Yukon Electrical is working jointly with Yukon Energy to evaluate LED street lights for the Yukon, which reduces load and, therefore, losses.

(c) There are no additional steps beyond what is included in the forecast that Yukon Electrical can reasonably undertake to reduce line losses. Yukon Electrical's engineering standards and system improvement projects directly reduce line losses. All new infrastructure is built to current engineering standards that inherently reduce losses.

As a result of the substantial growth in load over the past 10 years, losses could be expected to have increased during the period. However, average losses over the period 2003-2012 were 6.2%, which is equal to the losses forecast for the test years. Therefore, Yukon Electrical believes that the steps it has taken to reduce losses have been successful in preventing the level of losses from increasing as load has grown.

CW-YECL-6

Reference: Diesel Fuel, Application, page 4-2

In its Application, YECL states:

> Plant efficiencies are based on the average efficiencies of the previous five years adjusted for any changes due to the replacement of units. This is consistent with the approach approved in Board Order 2009-2.

In schedule 4.1, YECL provides a forecast of heat rates of 3.71 for each year in the test period. In Section 9 of its Application, YECL provides forecasts of capital for generation. On Schedule 4.1, the average of actual heat rates is 4.0, higher than the forecast of 3.71. The City requires information to understand how the efficiencies discussed in the application have been incorporated in the forecasts.

Request:

(a) For each generation project identified in section 9, please identify if it is for hydro or thermal generation.

(b) Please provide a working paper that demonstrates how the forecast heat rate of 3.71 relates to the historic data on Schedule 4.1. In the response, please also fully explain how the capital expenditures related to generation have impacted the forecast heat rates.

Response:

(a) Please refer to CW-YECL-6(a) Attachment 1.

(b) Please refer to CW-YECL-6(b) Attachment 1 for the calculation of the forecast heat rate based on the historic data on Schedule 4.1.

The capital expenditures on generation forecast for the test period have not impacted the forecast heat rates. Based on discussions with the vendors, Yukon Electrical understands that while the new units will have lower emissions they are unlikely to be more efficient from a heat rate perspective.

The Yukon Electrical Company Limited
Classification of Generation Projects as Hydro or Thermal

2008	
Fish Lake Unit #1 Generator End of Life Rebuild	Hydro
Haines Junction Plant Upgrades	Thermal
Pelly Crossing Tie into Transmission Grid	Thermal
Watson Lake Generator Upgrades and Fresh Air Intakes	Thermal
Destruction Bay Compton Protection Relay Replacement and Battery Charger Up	Thermal
2009	
Haines Junction Plant Controls Upgrade	Thermal
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	Hydro
Fish Lake Unit #1 Replacement Wheel	Hydro
Fish Lake Incremental Purchase Power	Hydro
Fish Lake Control Room Monitor Upgrade	Hydro
Swift River Unit #1 Replacement	Thermal
2010	
Fish Lake Unit #2 Penstock Replacement	Hydro
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	Hydro
Destruction Bay Unit #1 Replacement	Thermal
Watson Lake Unit #5 Replacement	Thermal
Fish Lake Unit #1 Spillway	Hydro
Purchase Unit for Pelly Crossing Power Plant	Thermal
Fish Lake Unit #1 Wheel Replacement	Hydro
Fish Lake Ditch #3 Drop Box Concrete Upgrade	Hydro
Swift River Unit #1 Replacement	Thermal
Pelly Crossing Plant Automation	Thermal
2011	
Fish Lake Unit #1 Turbine and Building Replacement	Hydro
Fish Lake Unit #1 Tailrace Reconstruction	Hydro
Fish Lake Penstock #2 Replacement	Hydro
Louise Lake Control Structure Gate Replacement	Hydro
Fish Lake Ditch #3 Concrete Upgrade at Drop Box and Bypass	Hydro
Fish Lake Dyke Widening	Hydro
Ross River Substation Improvements	Thermal
Purchase of Used Spare Generator	Thermal
Watson Lake Protection Upgrade	Thermal
Hobo for Franklin Lake Water Monitoring	Hydro
Teslin Programmable Logic Controller (PLC) Replacement	Thermal
Watson Lake Unit #5 Replacement	Thermal
Stewart Crossing Radio Replacement and Programmable Logic Controller (PLC) Upgrade for Remote Control	Thermal
Fish Lake Unit #1 Spillway	Hydro
Hobo Water Monitor for Fish Lake at Range Road	Hydro
High Voltage Switching Cubicle and Terminations for Old Crow Plant	Thermal
Teslin Plant Combustible Air Intake and Louver Improvements	Thermal
Fish Lake Unit #2 Wheel, Shaft, and Bearing Improvements	Hydro
Haines Junction Plant Relocation on to Foundation	Thermal
Ross River Unit Protection Relay	Thermal
Pelly Crossing Plant Automation	Thermal

2012

Fish Lake Unit #1 Turbine and Building Replacement	Hydro
Watson Lake Unit #4 Replacement	Thermal
Watson Lake Unit #3 Major Overhaul	Thermal
Beaver Creek Programmable Logic Control (PLC) Upgrade	Thermal
Fish Lake Unit #2 Step-up Transformer	Hydro
Fish Lake Unit #2 Turbine Inlet Valve (TIV) Replacement	Hydro
Beaver Creek Control Room Separation from Plant	Thermal
Carmacks Fuel System Upgrade	Thermal
Old Crow Generator Change Out	Thermal
Watson Lake Bi-Fuel Project	Thermal
Swift River Unit #2 Replacement	Thermal
Pelly Crossing Plant New Governors for Automation	Thermal
Teslin Fuel System Upgrade	Thermal
Ross River Fuel System Upgrade	Thermal
Water Pressure Monitor (Hobo) for Louise Lake	Thermal
Teslin Programmable Logic Controller (PLC) Replacement	Thermal
Destruction Bay Fuel System Upgrade	Thermal
Haines Junction Fuel System Upgrade	Thermal

2013

Fish Lake Unit #1 Turbine and Building Replacement	Hydro
Watson Lake Unit #4 Replacement	Thermal
500kW Mobile Generator	Thermal
Beaver Creek Unit #2 Replacement	Thermal
Watson Lake Bi-Fuel Project	Thermal
Fish Lake Dyke Upgrade	Hydro
Old Crow Plant Expansion	Thermal
Watson Lake Unit # 6 Major Overhaul	Thermal
Beaver Creek Programmable Logic Control (PLC) Upgrade	Thermal
New 250kW Mobile Generator	Thermal
Destruction Bay Plant Foundation Refurbishment	Thermal
Other Projects	Thermal
Fish Lake Unit #2 SCADA	Hydro
Fish Lake Unit #2 Penstock Improvements	Hydro
Fish Lake Unit #2 Siding Replacement	Hydro
Fish Lake Head Pond #2 Spillway Upgrade	Hydro
Swift River Unit #2 Replacement	Thermal
Fish Lake Unit #2 Vibration Monitoring	Hydro
Fish Lake Unit #1 Fiber Communication from Head Pond to Unit	Hydro
Fish Lake Unit #2 Building Improvements	Hydro
Fish Lake Unit #1 Spillway Diversion Structure	Hydro

2014

Old Crow Plant Expansion	Thermal
Fish Lake Ditch #3 Diversion Structure Replacement	Hydro
Fish Lake Dyke Upgrade	Hydro
Destruction Bay Unit #2 Replacement	Thermal
Old Crow Unit #4 Addition	Thermal
Destruction Bay Unit #3 Replacement	Thermal
Watson Lake Bi-Fuel Project	Thermal
Destruction Bay Programmable Logic Controller Upgrade	Thermal
Watson Lake Unit #5 Major Overhaul	Thermal
Watson Lake Replace ABB 5HK Breakers	Thermal
Stewart Crossing Plant Improvements	Thermal
Fish Lake Unit #1 Spillway Diversion Structure	Hydro
Other Projects	Thermal
Stewart Crossing Plant Building Insulation	Thermal
Ross River Replace ABB 5HK Breakers	Thermal
Fish Lake Unit #2 Head Pond Low Level Outlet Pipe	Hydro

2015

Carcross 2MVA Generation Standby Unit	Thermal
Watson Lake Unit #2 Replacement	Thermal
Beaver Creek Unit #1 Replacement	Thermal
Old Crow Unit #3 Replacement	Thermal
Watson Lake Unit #1 Major Overhaul	Thermal
Watson Lake Replace ABB 5HK Breakers	Thermal

The Yukon Electrical Company Limited
Calculation of Forecast Heat Rate

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	5-Year Average
Schedule 4.1, Line 2	3.65	3.69	3.74	3.68	3.70	3.69
Rounding *						0.02
2013-2015 Forecast Fuel Heat Rate						**3.71**

* The calculation of the 5-year average heat rate of 3.71 is based on a detailed 5-year average by plant. As a result, there is an immaterial rounding difference when the simple average of the historic heat rates, as shows on Schedule 4.1, is calculated.

CW-YECL-7

Reference: Operating Costs – DB Pension, Application page 5-3

In its application, YECL provides a table that summarizes DB pension costs. In the table, the costs for DB Special Payments increases from $297,000 in 2011 to $638,000 in 2012. The City requires information to assess the level of pension costs to be recovered from customers.

Request:

(a) Please confirm that YECL employees participate in the same DB pension plan as the employees of YECL's parent, ATCO Electric. If not confirmed, please fully explain and provide all plan documents related to the YECL DB plan.

(b) On line 7 and 8, YECL indicates it has used the same contribution rate for the 2013 test period. Please provide the forecast of DB pension costs included in 2013, 2014, and 2015.

Response:

(a) Not confirmed. Canadian Utilities Ltd. (CU) sponsors two pension plans: Plan 1 (DB and DC) and Plan 2 (DB only). Employees of Yukon Electrical's parent company, ATCO Electric, participate in Plan 1 for both DB and DC. Yukon Electrical employees who are members of the DC plan participate in Plan 1 while Yukon Electrical employees who are members of the DB plan participate in Plan 2 along with employees of other CU subsidiary companies.

The only difference between Plan 1 and Plan 2 is related to the regulation of the two plans. Plan 1 is registered in Alberta and, accordingly, is governed by the Alberta *Employment Pensions Plans Act* and administered and enforced by the Office of the Alberta Superintendent of Pensions in the Employment Pensions Branch in Alberta Treasury Board and Finance. Plan 2 is registered federally and, accordingly, is governed by the *Pensions Benefits Standards Act, 1985* and administered and enforced by the Office of the Superintendent of Financial Institutions ("OSFI"). For purposes of Plan 2, an actuarial report must be prepared annually except for when the solvency ratio is greater than 1.20. Given Plan 2's most recent Actuarial Report as of December 31, 2012 details a solvency ratio

less than 1.20, the next Actuarial Valuation will be required as of December 31, 2013.

(b) The forecast DB pension costs included in 2013, 2014, and 2015 are as follows:

Year	Defined Benefit (annual lump sum)	DB Special Payments (annual lump sum)	Defined Benefit Total
2013	$630	$638	$1,268
2014	$630	$638	$1,268
2015	$630	$638	$1,268

CW-YECL-8

Reference: Operating Costs- Lease of LNG, Application, page 5-4 and Business Case 6

In its Application, YECL states:

> In addition, Yukon Electrical purchases information technology and billing system services from ATCO I-Tek and ATCO I-Tek Business Services respectively. Beginning in the fall of 2013, Yukon Electrical will be leasing liquid natural gas (LNG) storage and vaporization equipment from an affiliate company, ATCO Gas, related to the Watson Lake Bi-Fuel Project. Please refer to Business Case #6 for further details on this project.

The City requires information to understand how the decision was made to lease the LNG facility, and how pricing was determined.

Request:

(a) Please provide any financial analysis prepared by YECL comparing the costs of the three alternatives in the Business Case.

(b) Please provide an analysis that demonstrates leasing LNG storage and vaporization equipment is less expensive than owning such equipment.

(c) Please fully describe the process that YECL undertook to determine that an affiliate should provide the equipment. In the response, please discuss whether competitive tendering was used.

(d) Please fully explain, and provide working papers in support of the lease price and its derivation.

Response:

(a) Alternative #1 relates to the status quo of continued operation to generate power using only diesel at no additional cost. A detailed financial analysis was not carried out on Alternative #2 to replace existing units with dual fuel capability as costs would be in excess of $9M. New individual unit costs range from approximately $1M to $1.5M. Each unit would also typically require new radiators, silencers, piping for both cooling and exhaust, and control system integration on top of unit purchase. Technology has changed between these

1990s vintage units and modern engines. As a result, it would not be a straight forward swap to accomplish replacement. The bi-fuel modification kit for an individual existing unit in selected Alternative #3 is approximately $75K. Additionally, a firm supply chain of LNG is not yet established and is to be developed as part of this project.

(b) Leasing equipment may not be less expensive than owning such equipment over the long term life of a project. However, for the purposes of the pilot project, the lease option is prudent as it does not require Yukon Electrical to invest upfront in the equipment, and it allows flexibility for exiting the project if the pilot is not successful. The equipment supply is one component of the lease arrangement. It also includes on-going services for operations and maintenance. If the market develops whereby the equipment and specialized services become more costly going forward, the lease arrangement provides additional cost certainty for the project to achieve fuel cost savings related to diesel. For additional information, please refer to CW-YECL-8(c) below.

This is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable. Yukon Electrical has structured the project to allow flexibility with respect to capital commitments and provision of necessary expertise that allows Yukon Electrical to, if necessary, exit the project after the pilot period without having invested the full capital required. This allows Yukon Electrical to evaluate on a go-forward basis the contractual arrangement for equipment and services. The cost of equipment is only one part of the lease arrangement. Yukon Electrical has taken the lease approach to secure an inclusive expert provider of natural gas rather than a consortium of consultants, equipment providers and specialized service providers. This bundled approach with ATCO Gas includes LNG storage and vaporization services along with their expertise related to systems design, purchasing, installation, commissioning, on-going operations support, maintenance, permitting, licensing for the project, regulator support, Health Safety and Environment policies, procedures and work instructions, regulations and safety. The equipment includes an LNG Facility comprised of on-site storage of LNG, LNG vaporizer and controls, natural gas odorizer, metering and facility safety systems.

(c) Yukon Electrical presently has a provider to supply diesel fuel for use in the Watson Lake Power Plant. Yukon Electrical has the expertise to utilize a new fuel and requires a supply of natural gas at the plant site to implement the bi-fuel project. Yukon Electrical contemplated the approach to consolidate a

consortium of consultants, equipment providers and specialized service providers. Yukon Electrical looked for a solution to minimize the risk to the project and determined that working with an affiliate with the necessary capabilities provided a more secure approach. The equipment being utilized is acquired utilizing ATCO Gas' competitive procurement process that involves engineering, financial and purchasing professionals. Yukon Electrical is involved in each step of the development of this system to ensure appropriate procurement methods are used and that cost expenditures are prudent. A competitive process was also used to secure LNG transportation services.

(d) A competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012. At that time, there were also no regulations, permits or procedures in the Yukon related to this unique project. To derive the lease price, ATCO Gas utilized a competitive procurement process that involved engineering, financial and purchasing professionals to assemble the combination of equipment and services. Yukon Electrical was involved in each step of the pricing process that went into the confidential contractual arrangement. Yukon Electrical has continued to investigate comparative benchmark pricing related to other service providers that may become available.

CW-YECL-9

Reference: Operating Costs – FTEs, Application, page 1-8

On page 1-8, YECL provides a table of FTEs. The City requires an understanding of the increase in FTEs.

Request:

(a) For each actual FTE identified in the table on page 1-8, please provide the date of hire.

(b) Please provide the forecast date of hire for each forecast FTE included in the table on page 1-8.

Response:

(a & b) Please refer to CW-YECL-9 Attachment 1.

In completing this response, Yukon Electrical has determined that it has inadvertently forecast all additions as of January 1 for each respective year. A more reasonable forecast is to have these additions forecast to occur mid-year. Yukon Electrical proposes to adjust this as part of its compliance filing.

The Yukon Electrical Company Limited
Dates of Hire

		Actual/Forecast Date of Hire
2009 Approved Complement	57.43	
Meter Reader (2010)	1.00	Apr-10
Senior Corporate Communications Advisor (2011)	0.60	Apr-11
Financial Analyst (2011)	1.00	Dec-10
Administrative Assistant (2011)	1.00	Jun-11
Planning Supervisor (2012)	1.00	Jun-12
Meter Reader (2012)	1.00	Oct-12
Corporate Accountant (2012)	1.00	Jan-12
Manager, Financial Reporting and Accounting, North of 60 (2012)	0.50	Jan-12
Engineer in Training (2012)	(1.00)	
Construction Lead (March 2012)	1.00	Feb-12
Engineering Tech 1 Civil (October 2012)	1.00	Oct-12
Engineering Assistant (October 2012)	1.00	Mar-12
2012 Actual Ending Complement	66.53	
Power Line Technician (PLT) Apprentice (2013)	1.00	Jan-13
Customer Service Advisor (2013)	1.00	Jan-13
Demand Side Management (DSM) Administrator (2013)	1.00	Jan-13
Customer Service Representative (2014)	1.00	Jan-14
Engineer in Training (2014)	1.00	Jan-14
Environmental Technician (2014)	1.00	Jan-14
Construction Assistant (2015)	1.00	Jan-15
Power Line Technician (PLT) Apprentice (2015)	1.00	Jan-15
Meter Reader (July 2015)	(1.00)	
Various Other	(0.14)	
2015 Forecast Ending Complement	73.39	

CW-YECL-10

Reference: Operating Costs, Application, Schedule 5-2

In Schedule 5-2, YECL provides variance explanation for changes in operating costs. The City requires information to assess the forecast operating costs.

Request:

(a) In lines 5-6, YECL explains the 2012 increase as being due to the Fish Lake Water License. In Lines 8-12, YECL explains the 2013 increase as being due to Fish Lake Water License. Please fully explain why there are cost increases in 2012 and 2013. Also, please provide a working paper that identifies all costs for the Fish Lake Water License for 2011, 2012, 2013, 2014, and 2015.

(b) On line 150-152, YECL indicates that in 2013, costs increase as a result of reclassifying one temporary meter reader to permanent. Please fully explain why, in light of its AMR program, YECL is increasing the number of permanent meter readers.

(c) On line 154-155, YECL indicates that in 2015, costs decrease as a result implementing its AMR program. Please fully explain how YECL will deal with existing meter readers, and the costs of reductions in staff.

(d) On line 194-195, related to account 72100, YECL explains cost increases in 2014 as being related to a 2015 Phase II application. On line 200-207, related to account 72200, YECL mentions regulatory costs. Please fully explain how YECL accounts for regulatory costs.

Response:

(a) There are cost increases in 2012 and 2013 due to labour and fringe increases as well as various contractor costs as shown in YUB-YECL-8 Attachment 1. Additionally, this schedule shows costs from 2011 – 2015.

(b) Another term meter reader is necessary to perform the function of meter reading safely and accurately until AMR is fully implemented. The existing complement of 2 Meter Readers has been unable to complete all meter reads due to excessive

workload. Due to inability to complete meter reads with Meter Readers, Powerline Technicians and Field Service Representatives were required to assist. On a go forward basis, these Technicians and FSRs are needed for system projects as opposed to meter reading.

(c) Once AMR is implemented, the existing meter reader complement will be reduced by one position in 2015 and one position in 2016. There will be no additional cost for the staff reduction as these positions are term employees and there is no requirement for severance pay. Once AMR is fully implemented, Yukon Electrical will have one Meter Reader to read the remaining conventional meters.

(d) For the test period 2013-2015, all regulatory related costs are forecast in two separate accounts:

- Yukon Electrical Labour and Affiliate Labour is included in O&M and located in account 72100. Please refer to Schedule 5.3 for Affiliate charges.

- Board-approved costs for External Consultants as well as Yukon Electrical incremental disbursements for Regulatory Phase I & II processes have been included in the Rate Case Reserve as detailed in Schedule 8.9 of the Application.

For the historical years 2008-2012, Yukon Electrical coded all other regulatory costs incurred into account 72200. For 2013-2015, no regulatory costs have been forecast in account 72200. The breakdown of costs included in account 72200 is as follows:

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
Bank Charges	29	42	71	93	135	137	140
Regulatory Expenses	120	142	-	103	-	-	-
	149	184	71	196	135	137	140

Bank charges are forecast to increase as a result of the continued increase in customer credit card usage in 2013.

CW-YECL-11

Reference: Cost of Debt, Application, page 8-6

In its Application, YECL has forecast increased cost of new long term debt in 2014 and 2015. The City requires information to assess the forecasts.

Request:

(a) Please fully explain how new long term debt is sourced by YECL? Is new debt mirrored down from an affiliate, such as ATCO Electric, Canadian Utilities, or ATCO? How is the cost of new debt derived?

(b) Please provide the forecast of YECL's parent, ATCO Electric (AE) for long term debt from each of the last three GTAs. (amounts, dates and rates)

(c) Please provide the actual issues of long term debt for the same periods as identified in (b) above. (amounts, dates and rates)

Response:

(a) The gross proceeds of a CU Inc. issue are advanced to Yukon Electrical's parent, ATCO Electric Ltd. The interest rate on the debenture ATCO Electric issues to CU Inc. is the same coupon interest rate as on the CU Inc. debentures issued to the public. ATCO Electric pays CU Inc. its pro-rata share of CU Inc.'s issue costs at the time the debenture is issued. ATCO Electric then amortizes the issue costs on a monthly basis over the term of the debenture.

ATCO Electric, in turn, advances funds to Yukon Electrical on the same understanding – i.e., that Yukon Electrical will reimburse ATCO Electric for its pro-rata share of the issue costs incurred by ATCO Electric. In the case of Yukon Electrical, this monthly amortization is considered to be administratively inefficient, given the relatively small sums involved. It is considered to be more efficient for the issue costs to be "rolled into" the interest rate and be paid to ATCO Electric over the life of each debenture. Accordingly, the coupon interest rate on the Yukon Electrical debenture is set equal to the embedded rate (i.e. the coupon interest rate on the CU Inc. debentures issued to the public interest rate plus an amount to cover issue costs).

Yukon Electrical has forecast the amount to be added to the coupon rate for issue costs to be 5 basis points for 2013-2015. This is the same amount used in previously approved applications and is based on an estimate of the costs that CU Inc. will incur when it issues debentures to the public.

(b) In the following table, please find ATCO Electric's forecast long term debt issuance dates and rates from each of its last three GTAs. The forecast amount of debt to be issued by ATCO Electric is not relevant to Yukon Electrical's Application as the two companies have materially different capital programs which drive materially different financing requirements.

Year	Issue Date	Issue Rate
2007	2007-06-30	5.20%
2008	2008-06-30	5.20%
2009	2009-06-30	6.65%
2010	2010-06-30	6.65%
2011	2011-06-30	5.75%
2012	2012-06-30	6.35%

(c) In the following table, please find ATCO Electric's actual long term debt issuance dates and rates for the same periods identified in part (b). The actual amount of debt issued by ATCO Electric is not relevant to Yukon Electrical's Application as the two companies have materially different capital programs which drive materially different financing requirements.

Year	Issue Date	Issue Rate
2007	2007-11-01	5.556%
2008	2008-05-26	5.563%
	2008-05-26	5.580%
2009	2009-03-06	6.215%
	2009-03-07	6.500%
2010	2010-11-10	4.947%
2011	2011-10-24	4.543%
	2011-10-24	4.593%
2012	2012-09-10	3.805%
	2012-09-10	3.825%
	2012-11-14	3.857%

In comparing forecast rates from part (b) above to actual rates in this part (c), there are instances where forecast rates were lower than actuals and others where they were higher than actuals. The reason actual rates were lower than forecast for the 2010 to 2012 period was the impact of central bank stimulus activity since the 2008/2009 global financial crisis. As a result of these activities and general market uncertainty, Government of Canada Bond Rates unexpectedly dropped to historic lows. The forecasts used for the 2010 to 2012 period did not reflect this unexpected move in Government of Canada Bond Rates. The external forecasts relied upon for 2013 to 2015 period take into consideration central bank stimulus activities and expectations for how those activities will gradually recede over time, which will result in interest rates increasing to more “normal” levels.

CW-YECL-12

Reference: Capital Expenditures, Application, pages 9-44 to 9-67

In the Application, YECL provides an explanation of capital expenditures.

Request:

(a) On page 9-46, YECL provides Miscellaneous O/H Services – Various Subdivisions of $3,625,000 for 2013. On page 9-56, YECL provides a 2014 forecast of $2,900,000, and on page 9-62, YECL provides a 2015 forecast of $4,300,000.

(i) Please fully explain how the forecasts were determined.

(ii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(iii) Please provide new overhead customers added in each of 2008-2015.

(iv) Please fully explain changes in cost per service in each year.

(b) On page 9-46, YECL provides forecast costs for New Underground Line Extensions of $600,000 for 2013. On page 9-56, YECL provides a 2014 forecast of $1,000,000, and on page 9-62, YECL provides a 2015 forecast of $1,000,000.

(i) Please fully explain how the forecasts were determined.

(ii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(iii) Please provide new underground customers added in each of 2008-2015.

(iv) Please fully explain changes in cost per service in each year.

(c) On page 9-47, YECL discusses a Downtown Whitehorse 4L313 Lambert Street to Eliot Street project to replace overhead with underground at a cost of $424,000. Please fully explain why this overhead line is being replaced with

underground. Also, please provide the cost of replacing overhead with overhead.

(d) On page 9-47, YECL provides forecast costs for Right of Way Widening of $374,000 for 2013. On page 9-57, YECL provides a 2014 forecast of $389,000, and on page 9-63, YECL provides a 2015 forecast of $405,000.

(i) Please fully explain why YECL is conducting this program.

(ii) Please fully explain how the forecasts were determined.

(iii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(iv) Please fully explain why there is no business case for this project.

(e) On page 9-48, YECL provides forecast costs for Miscellaneous Distribution Pole Replacements of $260,000 for 2013. On page 9-57, YECL provides a 2014 forecast of $260,000, and on page 9-64, YECL provides a 2015 forecast of $260,000.

(i) Please fully explain how the forecasts were determined.

(ii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(f) On page 9-48, YECL provides forecast costs of Downtown Whitehorse 4L316 6th Avenue 266 Reconductor of $250,000 for 2013. On page 9-57, YECL provides a 2014 forecast of $360,000.

(i) Please fully explain why YECL is conducting this program.

(ii) Please fully explain how the forecasts were determined.

(iii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(iv) Please fully explain why there is no business case for this project.

(g) On page 9-48, YECL provides forecast costs for PCB Identification and Transformer Change Outs of $175,000 for 2013. On page 9-58, YECL provides a 2014 forecast of $100,000, and on page 9-65, YECL provides a 2015 forecast of $100,000.

(i) Please fully explain how the forecasts were determined.

(ii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(h) On page 9-49, YECL provides forecast costs for Test and Treat Program of $110,000 for 2013. On page 9-58, YECL provides a 2014 forecast of $120,000, and on page 9-64, YECL provides a 2015 forecast of $130,000.

(i) Please fully explain how this program is different from the "Miscellaneous Distribution Pole Replacement" program.

(ii) Please fully explain how the forecasts were determined.

(iii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(i) On page 9-50, YECL provides forecast costs for Miscellaneous Street Light Replacements of $330,000 for 2013. On page 9-59, YECL provides a 2014 forecast of $450,000.

(i) Please fully explain why YECL is conducting this program.

(ii) Please fully explain how the forecasts were determined.

(iii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(iv) Please fully explain why there is no business case for this project.

(j) On page 9-66, YECL provides a forecast for New Street Light Installations of $483,000. Please provide:

(i) the historic data YECL used when its states the forecast is based on "fully contributed new street light installations".

(ii) an analysis and discussion of the number and sites for new streetlights.

(k) On page 9-51, YECL provides forecast costs for Transportation Equipment of $424,000 for 2013. On page 9-59, YECL provides a 2014 forecast of $995,000, and on page 9-67, YECL provides a 2015 forecast of $850,000.[1]

(i) Please provide YECL's policy for the replacement of transportation equipment.

(ii) Please provide the cost of each unit forecast for 2013, 2014, and 2014.

(iii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(l) On page 9-46, YECL provides forecast costs for Land Rights of $190,000 for 2013. On page 9-56, YECL provides a 2014 forecast of $190,000, and on page 9-62, YECL provides a 2015 forecast of $190,000.

(i) Please fully explain how the forecasts were determined.

(ii) Please provide historic actual results for this category for 2008, 2009, 2010, 2011, and 2012.

(m) On page 9-64, YECL provides forecast costs for MacDonald Road Pole Change of $250,000 for 2015.

(i) Please fully explain how this program is different from the "Miscellaneous Distribution Pole Replacement" program.

(ii) Please fully explain how the forecasts were determined.

[1] Replacement of unit 989 of $450,000 and replacements of units 747, 851, 885, and 887 of $400,000

(iii) Please fully explain how the costs of this program are not implicitly included in the forecast for the "Miscellaneous Distribution Pole Replacement" program.

Response:

(a) (i) The forecast for New Extensions, including the Miscellaneous O/S Services, is based on the knowledge that Yukon Electrical has of areas of development within its service areas as well as based on historical customer additions. New extensions are, on average, 75-80% funded by customer contributions. For the net investment for the New Extension Category, including Miscellaneous O/S Services, please refer to YUB-YECL-65.

(ii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011 and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(iii) Yukon Electrical does not track new overhead customers compared to underground customers.

(iv) Yukon Electrical does not track average cost per service as cost per service is dependent on a number of factors such as the length of line, type of service requirement and site conditions. The site conditions can vary greatly for country residential services.

(b) (i) The forecast for New Extensions, including the New Underground Line Extensions, is based on the knowledge that Yukon Electrical has of areas of development within its service areas as well as based on historical customer additions. New extensions are, on average, 75-80% funded by customer contributions. For the net investment for the New Extension Category, including Miscellaneous O/S Services, please refer to YUB-YECL-65.

(ii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011 and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(iii) Yukon Electrical does not track new overhead customers compared to underground customers.

(iv) The costs per service are variable based on the design and scope of the underground project. Yukon Electrical, in consultation with the customer, will design the project to connect the customer to the distribution system in accordance with standards. Residential customers are generally similar in design. Commercial and multi residential properties will vary greatly depending on electrical service needs of the customer.

(c) The existing 4L313 overhead line is being replaced as the line is near maximum capacity during normal system operations. It is being replaced with underground electrical infrastructure due to lack of clearances to existing buildings to meet code. It is not possible to replace the existing overhead line with new overhead line and meet Utility Code requirements. As it is not possible to build overhead distribution in this area, a cost estimate was not developed.

(d) (i) Yukon Electrical is conducting the Right of Way Widening program to allow for safer power line access for maintenance and emergencies, to reduce the potential for wild fires resulting from contact with power lines and to improve customer reliability and safety by having less tree contacts with the distribution system.

(i) Forecasts are based on historical costs of manageable work that can be safely completed in a given year with the available resources. In a calendar year, there are approximately 7 months that brushing work can be completed efficiently due to winter weather and snow loading. With the annual Right of Way Widening budget we are able to complete brushing work in coordination with our Maintenance brushing program. The forecast costs are increased each year to manage inflation and contractor pricing.

(iii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011 and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(iv) The Right of Way Widening program has been an annual system improvement project since 2005. No single year costs exceeded the $500k threshold for a business case.

(e) (i) The forecasts for Miscellaneous Distribution Pole Replacements are based on recent historical costs for these projects.

(ii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011 and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(f) (i) The line 4L316 is a key distribution line in the downtown core that provides an interconnection between multiple substations. With the interconnection to multiple substations the significant load in the downtown core can be served by a combination of substations. If any of the substations are out of service, planned or unplanned, the existing 4L316 will be at its design maximum to supply the downtown core.

(ii) The forecasts were determined based on the design and project scope.

(iii) There are no actual results for this project in past years.

(iv) These projects are based on two separate and distinct stages of upgrades for 4L316 that are stand alone projects. The different stages have specific benefits for the areas of the distribution system that will be upgraded. The cost for each of the two separate stages was below the $500k threshold for a business case.

(g) (i) The forecast costs were based on the number of transformers that Yukon Electrical currently has in stock and in service that do not have clear identification of PCB content. The forecast costs for required testing and disposal were made based on ATCO Electric's actual costs for a similar program.

(iii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011 and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(h) (i) The "Miscellaneous Distribution Pole Replacement" program is for replacing poles that are identified as deficient. The "Test and Treat Pole" program evaluates the existing poles structural integrity (wood condition)

to determine which poles require replacement and which poles are able to be treated to extend the life of the pole.

(ii) The forecasts were based on evaluating approximately 2,000 poles each year. Yearly increases account for inflation and increase in contractor fees.

(iii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011, and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(i) (i) This program is part of Yukon Electrical's annual distribution system improvement programs. Evaluation and condition assessments of street light davits are part of our system inspection program. The inspections identify street lights that are deficient or at end of life condition with rusted metal, broken or worn anchor bolts, deteriorated concrete bases and damaged or broken supply wires.

(ii) Each year has a specific area identified for planned upgrades or replacements. Please refer to YUB-YECL-69 for the areas identified for updates or replacements in 2013, 2014 and 2015. The forecasts are determined on preliminary project scope and engineering design.

(iii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011, and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(iv) The "Miscellaneous Street Light Replacements" program does not have a business case as it is an annual system improvement project that has not exceeded $500k.

(j) (i) The "New Street Light Installations" are for new lights that are fully contributed by the customer requesting the lights for amounts greater than Yukon Electrical's maximum investment level, which is currently set at $1,240 per light. The net investments by Yukon Electrical in 2013, 2014 and 2015 are $405,000 $570,000 and $547,000, respectively. The forecast is based on Yukon Electrical's best estimate of customer requests for street lights in 2015.

(ii) All these lights are built at the request of the customer. Designs for roadways are done to Transportation Association of Canada Guidelines or at the approval of the entity responsible for the roads. The forecast for 2015 is based on the planned future stages of Whistle Bend as determined by the City of Whitehorse and the historical demand of other Yukon Electrical service areas.

(k) (i) Key considerations for the replacement of transportation equipment include the age, mileage and required costs to repair to acceptable working condition. Service vehicles are mechanically evaluated when they reach 170,000 kilometers and 7 years of age.

(ii) 2013:

Stringing Trailer	$30,000
Hydraulic Cable/Wire Puller	$35,000
Unit 674 Replacement	$70,000
Unit 675 Replacement	$30,000
Unit 161 Replacement	$30,000
Unit 163 Replacement	$70,000
New service truck	$30,000
Unit 372 Replacement	$80,000
Zoom Boom Lift	$49,000
	$424,000

2014:

Warehouse Forklift	$90,000
Unit 777 Replacement	$230,000
Unit 887 Replacement	$230,000
Unit 780 Digger	$375,000
Unit 164 Replacement	$70,000
	$995,000

2015:

Hot Line Bucket Truck	$450,000
Unit 747 Replacement	$100,000
Unit 851 Replacement	$100,000
Unit 882 Replacement	$100,000
Unit 955 Replacement	$100,000
	$850,000

(iii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011, and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(l) (i) The forecasts for Land Rights are based on the planned distribution and capital projects that will require easements and land tenure. There is also a planned focus to secure easements and licences for existing power lines. The reorganization of the Engineering department will allow focus to secure power lines that do not have easements.

(ii) Please refer to Section 9 – Capital Additions for the total historic actual results for this category for 2008, 2009, 2010, 2011, and 2012. To see the additions in table form, please refer to the response to YUB-YECL-61 Attachment 1.

(m) (i) This specific project addresses a combination of clearance issues and voltage imbalances in an Industrial subdivision. These issues have been identified and the project was created to address. The “Miscellaneous Distribution Pole Replacement” is for various poles in various locations throughout Yukon Electrical’s service area that are identified by field personnel.

(ii) An initial project scope and preliminary engineering have been completed to forecast costs.

(iii) Please refer to response to CW-YECL-12(m)(i).

CW-YECL-13

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 2

In its business case, YECL asserts that the project has clear economic benefits.

The City requires information to assess these assertions.

Request:

(a) Please provide an analysis of the load of YECL and the various sources that clearly demonstrates that this facility is needed, and current and projected load cannot be served from other sources.

(b) Please provide the working papers that support YECL's projection of the costs of energy of 6.7 cents.

Response:

(a & b) Please refer to the response to information request YUB-YECL-37.

CW-YECL-14

Reference: Capital Expenditures – Business Cases, Business Case 3

In Business Case 3, YECL indicates it will be replacing an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

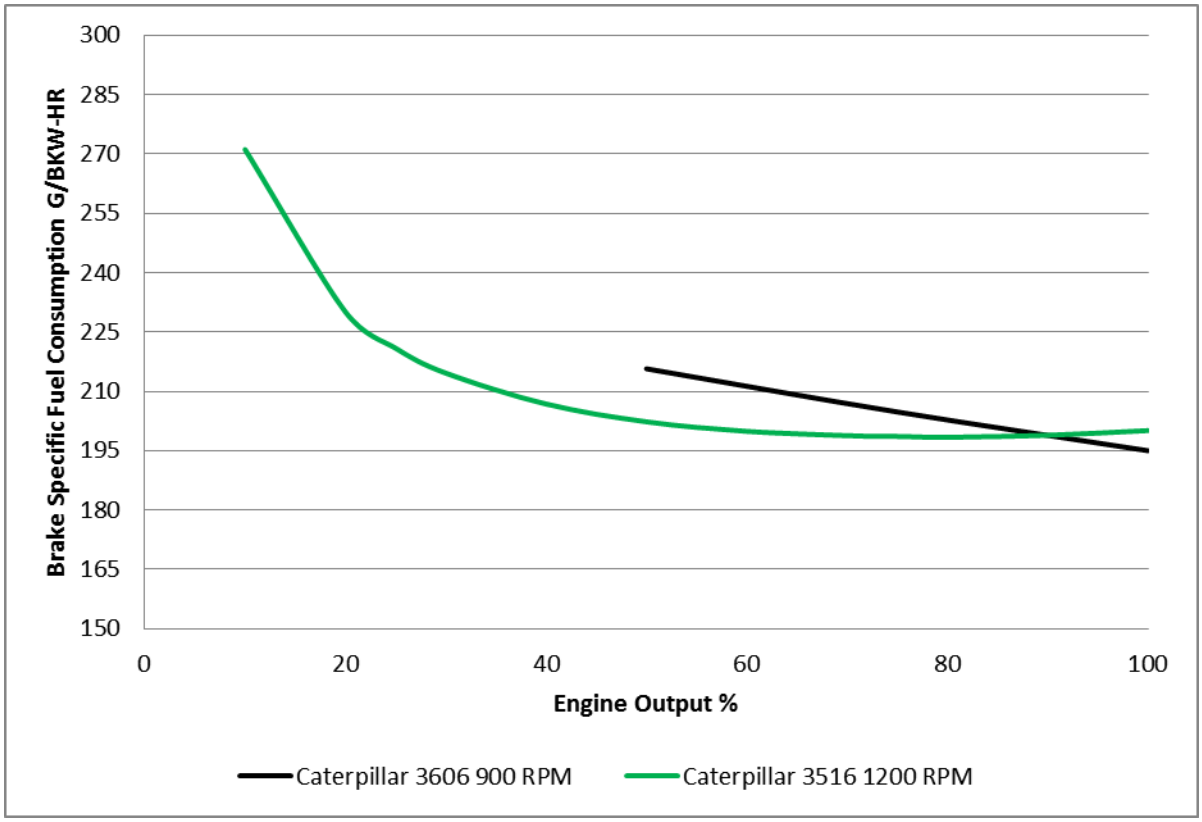
Request:

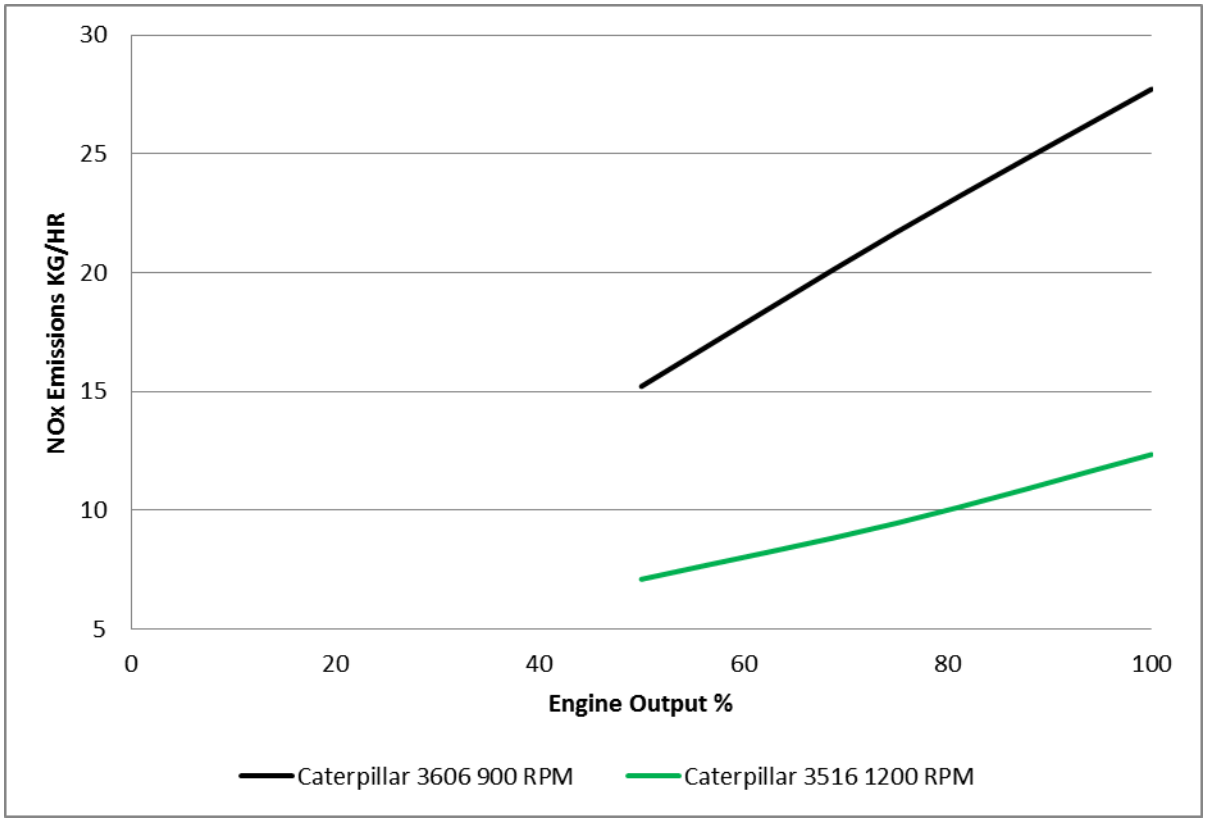
(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes have been incorporated into forecasts of diesel fuel.

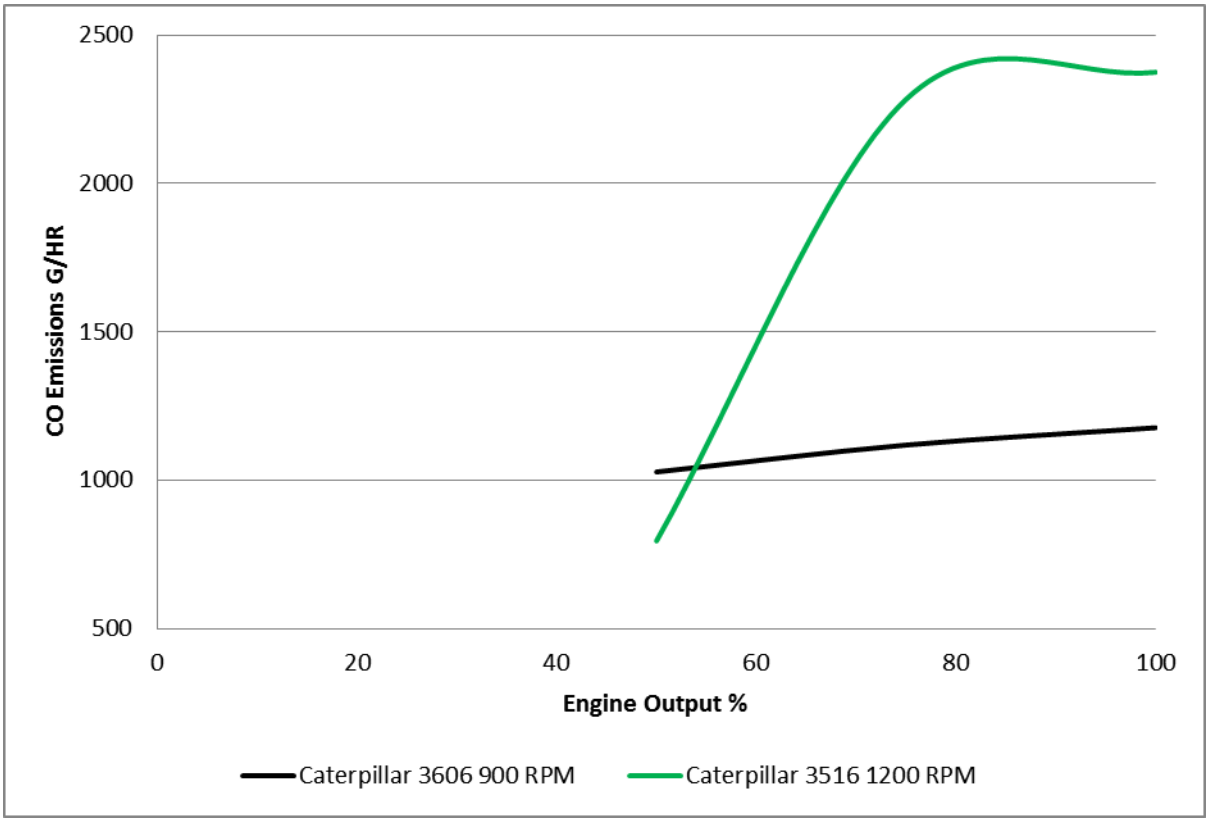
Response:

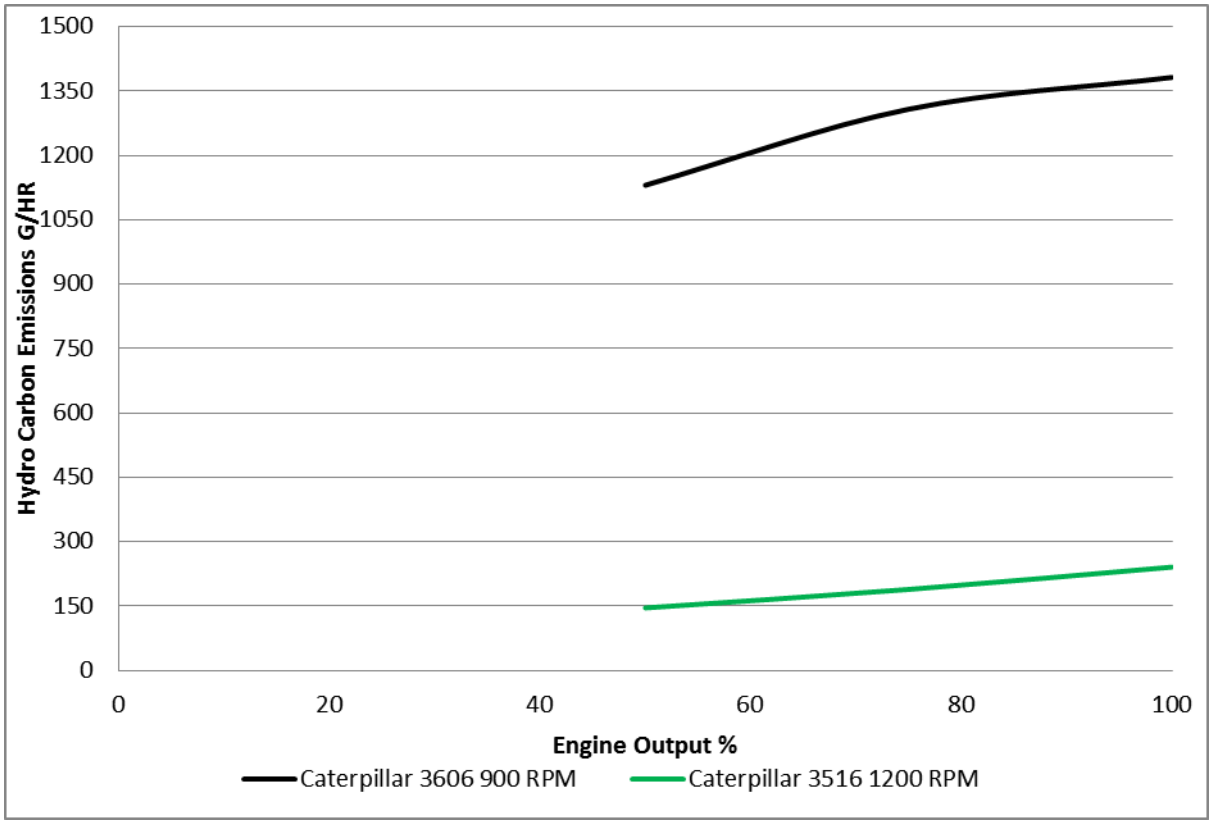
(a) Please refer to the charts below for a comparison of fuel consumption between the new 3516 1200RPM unit and the existing 3606 900RPM unit.

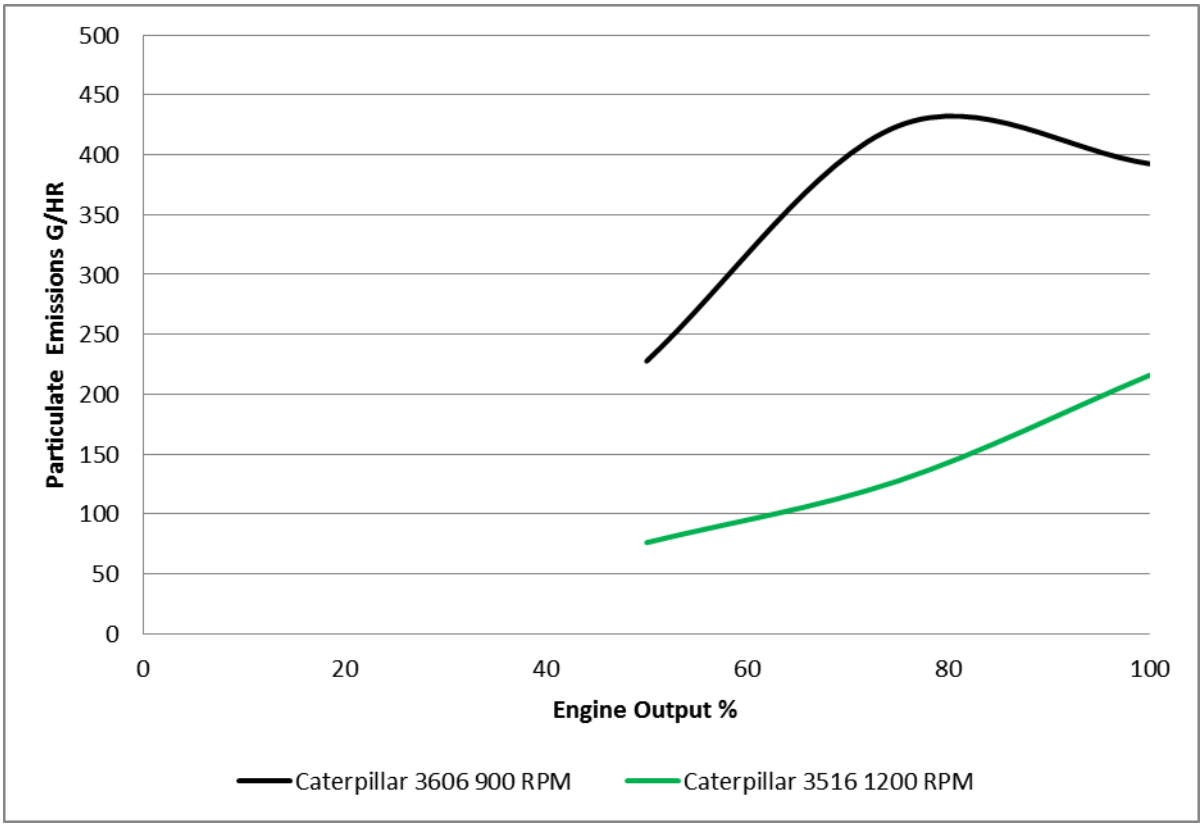
As detailed in its Application, Yukon Electrical forecasted its plant efficiencies based on an average of the previous five years. In the case of Watson Lake and implement of the bi-fuel project, Yukon Electrical has not been able to accurately forecast plant efficiency going forward. In order to address this issue, Yukon Electrical is requesting to use the actual equivalent diesel litres used as opposed to derived litres that are based on a forecast plant efficiency to arrive at the fuel deferral amount for Watson Lake.


Brake Specific Fuel Consumption G/BKW-HR
300
285
270
255
240
225
210
195
180
165
150
0
20
40
60
80
100
Engine Output %
Caterpillar 3606 900 RPM
Caterpillar 3516 1200 RPM


30
25
20
15
10
5
NOx Emissions KG/HR
0
20
40
60
80
100
Engine Output %
Caterpillar 3606 900 RPM
Caterpillar 3516 1200 RPM


2500
2000
1500
1000
500
CO Emissions G/HR
0
20
40
60
80
100
Engine Output %
Caterpillar 3606 900 RPM
Caterpillar 3516 1200 RPM


1500
1350
1200
1050
900
750
600
450
300
150
0
Hydro Carbon Emissions G/HR
0
20
40
60
80
100
Engine Output %
Caterpillar 3606 900 RPM
Caterpillar 3516 1200 RPM


500
450
400
350
300
250
200
150
100
50
0
Particulate Emissions G/HR
0
20
40
60
80
100
Engine Output %
Caterpillar 3606 900 RPM
Caterpillar 3516 1200 RPM

CW-YECL-15

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 4

In Business Case 4, YECL indicates it will require a new mobile generator. In the business case, YECL provides four alternatives. The City requires information to assess the chosen alternative.

Request:

(a) Please provide a financial analysis that compares the four alternatives, and demonstrates that the chosen option is the least cost option.

Response:

(a) The only financial analysis performed was on the forecast of costs for the new generator. This new mobile generator is included in this Application because it is needed to provide adequate contingency in the isolated diesel generation communities. The existing 350kW mobile backup generator is no longer large enough to meet the current peak loads of all of the communities it services. The other alternatives, including continued use of the existing 350kW generator, do not address the business need to have adequate contingency for customers.

CW-YECL-16

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 5

In Business Case 5, YECL indicates it will be replace an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

Request:

(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes in efficiency have been incorporated into forecasts of diesel fuel.

Response:

(a) Yukon Electrical is unable to provide an analysis that compares the efficiency of the old and new units for the following reasons:

- The vendor of the proposed new unit was contacted several times for information regarding the efficiency of the unit, but was unable to provide any information to Yukon Electrical.

- Yukon Electrical measures efficiency at the plant level and does not track the efficiency of each individual unit. As a result, there is no data on the current unit with which to compare the new unit's efficiency (if it were available).

Yukon Electrical notes that new diesel engines have to meet improved emission standards. This often means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power performance.

The primary driver for this project is the need for a new unit due to the end of life condition of the existing unit, not increased efficiency. As a result, Yukon Electrical has not incorporated efficiency into its business case for the need for this project.

As the change in efficiency resulting from the new unit is not currently known, no changes in efficiency have been incorporated into the diesel fuel forecast for the test years 2013-2015. Any increases or decreases in efficiency will be factored into a future application, once the unit is operational and the impact on overall efficiency for the Beaver Creek plant is known.

CW-YECL-17

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 7

In Business Case 7, YECL has proposed to upgrade the Fish Lake Dyke. The City requires information to assess the request.

Request:

(a) Please provide a copy of the referenced water license HY10-083 and the referenced 2012 Dam Safety Report.

(b) Please provide an explanation of the options available to YECL to address the issue.

Response:

(a) Please refer to CW-YECL-17(a) Attachment 1 for a copy of the referenced water licence HY10-083.

Please refer to CW-YECL-17(a) Attachment 2 for a copy of the 2012 Dam Safety Report.

Please refer to CW-YECL-17(a) Attachment 3 for a copy of Yukon Electrical's current 25-year water licence HY12-065 that was effective May 31, 2013.

(b) A recommendation to upgrade the Fish Lake Dyke was identified in the 2007 Dam Safety Review completed for Yukon Electrical for the Fish Lake Hydro system (this is recommendation #2008-04 carried forward and is identified in 2012 Dam Safety Report on page 6 of 54 of CW-YECL-17(a) Attachment 2). As a condition of Yukon Electrical's Interim Water Use License HY07-018, clause 25, Yukon Electrical had to address all recommendations in the 2007 Dam Safety Review. Yukon Electrical developed interim operating protocols to address issues with the Fish Lake Dyke until final design was approved in our current long term Water Use License HY12-065 (please refer to page 7 of 18 of CW-YECL-17(a) Attachment 3). The only prudent option available to address this issue was to upgrade the Fish Lake Dyke to the required engineering standard.

YUKON WATER BOARD

Pursuant to the *Waters Act* and Regulation, the Yukon Water Board hereby grants a Type A Water Use Licence for a power undertaking to:

Yukon Electrical Company Ltd.
100-1100 First Avenue
Whitehorse YT Y1A 3T4

LICENCE NUMBER: HY10-083

RENEWAL: This licence is deemed to be a renewal of HY07-018.

LICENCE TYPE: A **UNDERTAKING:** Power, Class 1

WATER MANAGEMENT AREA: 02

LOCATION: Fish Lake, Louise Lake, Bonus Creek, Porter Creek and West McIntyre Creek

PURPOSE: Operation of the Fish Lake Generating Station and the Fish Lake Dam as described in Water Use Application HY10-083.

EFFECTIVE DATE: September 1, 2011 **EXPIRY DATE:** March 31, 2013

This licence shall be subject to the restrictions and conditions contained herein and to the restrictions and conditions contained in the *Waters Act* and the *Waters Regulation* made thereunder.

Approved this 5th day of August, 2011

Witness

Minister, Executive Council Office
Government of Yukon

Issued this 10th day of August, 2011

Witness

Chairperson
Yukon Water Board

PART A - DEFINITIONS

"Act" means the *Waters Act* and any amendments thereto.

"Application" and "Water Use Application" means Water Use Application HY10-083, including any additional submissions and/or revisions, submitted to the Board by the Licensee.

"Board" means the Yukon Water Board.

"Dam Safety Guidelines" means the most current version of the Dam Safety Guidelines issued by the Canadian Dam Association.

"Decommissioning Plan" means the *Fish Lake Hydro Decommissioning Plan*, dated September 2, 2010, or the most current version.

"Ramping" means the act of changing discharge from a control structure.

"Regulation" means the *Waters Regulation* made under the Act.

PART B – GENERAL CONDITIONS

Other Laws

1. No condition of the water use licence limits the applicability of any statutory authority.

2. All water uses and activities authorized by this licence shall occur on property that the Licensee has the right to enter upon and use for that purpose.

Correspondence

3. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

    a) To the Licensee, if left at, faxed to, or mailed by registered mail to the following address:

    Yukon Electrical Company Ltd.
    100-1100 First Avenue
    Whitehorse YT Y1A 3T4
    Fax: (867) 633-5797

    and shall be deemed to have been given to the Licensee on the day it was left or faxed, or 7 days after the day it was mailed, as the case may be.

b) To the Board, if left at, faxed to, or sent by registered mail to the following address:

Yukon Water Board
Suite 106-419 Range Road
Whitehorse YT Y1A 3V1
Fax: (867) 456-3890

and shall be deemed to have been given to the Board on the day it was left or faxed, or 7 days after the day it was mailed, as the case may be.

c) The Board or the Licensee may, by notice in writing, change its address for delivery.

Non-Compliance

4. In the event that the Licensee fails to comply with any provision or condition of this licence, the Board may, with the approval of the Minister and subject to the Act, cancel the licence.

Spills and Unauthorized Discharges

5. The Licensee shall immediately contact the 24-hour Yukon Spill Report telephone number (867) 667-7244, should a spill or an unauthorized discharge occur. A detailed written report on any such event, including but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than 10 days after its occurrence.

Hazardous Materials Storage

6. A complete inventory of chemicals, fuels, oils and other hazardous materials and their locations shall be maintained by the Licensee. An up to date spill contingency plan suitable for such materials shall be maintained. Any revisions to the spill contingency plan shall be submitted to the Board within 60 days of the revision.

Annual Reports

7. Annual reports shall be submitted to the Board by the Licensee. The initial report shall cover the period from the effective date of this licence to December 31, 2011 and shall be submitted to the Board on or before February 28, 2012. Subsequent reports shall cover the period from January 1st to December 31st of each year and shall be submitted to the Board on or before February 28th immediately following the end of the reporting period.

8. Annual reports shall include the information required by this licence and by the Regulation, including, but not necessarily limited to:

   a) monthly maximum and minimum daily mean water levels on Fish Lake, Franklin Lake and Louise Lake;

   b) monthly maximum and minimum daily mean water flows through the gates of the Fish Lake Dam;

   c) monthly maximum and minimum daily mean flows through the Fish Lake generating station turbines;

   d) monthly maximum and minimum daily mean flows through the Louise Lake control structure;

   e) information regarding the purpose, nature and extent of any significant maintenance work carried out; and

   f) any other information or reports required by this licence or the Regulation.

Quarterly Reports

9. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31st, June 30th, September 30th and December 31st of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

10. Quarterly reports shall include the information required by this licence and by the Regulation, including, but not necessarily limited to:

    a) mean daily water levels on Fish Lake, Franklin Lake and Louise Lake;

    b) mean daily flow through the gates of the Fish Lake Dam;

    c) mean daily flows through the Fish Lake Generating Station turbines;

    d) mean daily flows through Ditch #1 and the overflow spillway;

    e) mean daily flows through Pond #1 and Pond #2;

    f) flows and water levels for spills from Pond #2;

    g) flows from Louise Lake Control Structure, Louise Lake Auxiliary Spillway, Plant #1 and Plant #2;

    h) flows through Ditch #3; and

i) any other information or reports required by this licence or by the Regulation.

Reports

11. All reports required to be submitted to the Board will be unbound and reproducible by standard photocopier, accompanied by one electronic copy on a CD/DVD.

12. The Licensee shall provide to the Board 5 additional copies of all reports. The additional copies may be either 5 bound paper copies or 5 electronic copies on individual CDs/DVDs.

13. Electronic copies shall be IBM compatible in one of the following formats: Word 97 - 2003, Excel 97 - 2003 workbooks, or Adobe .pdf format. Water quality results must be presented in Excel 97-2003 .xls format.

Term of Licence

14. The term of this licence is from the effective date to March 31, 2013.

PART C - OPERATING CONDITIONS

Description of Water Use

15. The Licensee is hereby authorized to:

a) obtain water from Fish Lake, Louise Lake, Porter Creek, and West McIntyre Creek;
b) store water in Fish Lake, Louise Lake, Head Pond #1 and Head Pond #2;
c) divert the flow of Fish Creek into Louise Lake Ditch #3;
d) divert flows to Franklin Lake via the Ditch #3 diversion subsequent to its rehabilitation;
e) divert the flow from Louise Lake into Porter Creek via Ditch #2;
f) divert the flow of Porter Creek into Head Pond #1;
g) use stored and/or diverted water for the purpose of power generation at Hydro Plant #1 and Hydro Plant #2;
h) discharge water into McIntyre Creek from Hydro Plant #2 at a maximum rate not to exceed 1.56 m^3/s or 49,196,160 m^3/year;
i) divert the flow between Louise Lake and Franklin Lake via the auxillary spillway; and
j) discharge water to Franklin Lake, Porter Creek, and West McIntyre Creek,

as described in the Application and subject to the conditions of this licence. Where there is a discrepancy between the Application and this licence, the conditions of this licence shall prevail.

Water Surface Elevations

16. The water surface elevation on Fish Lake shall be maintained between a controlled minimum of 1110.792 metres and a controlled maximum of 1112.292 metres as measured from geodetic datum.

17. The maximum water surface elevation on Fish Lake on April 15th of each year shall be 1111.99 metres as measured from geodetic datum.

18. The water surface elevation on Louise Lake shall be maintained between a controlled minimum of 1013.727 metres and a controlled maximum of 1014.607 metres as measured from geodetic datum.

19. The water surface elevation in Head Pond #2 shall be maintained between elevation 796.0 metres and 797.0 metres as measured from geodetic datum.

Minimum Instantaneous Flows

20. A minimum instantaneous flow of 0.28 m^3/s shall be discharged through the Fish Lake control structure except during the Minimum Flow Study outlined in clause 26 of this licence.

21. A minimum instantaneous flow of 0.14 m^3/s shall be discharged through the Louise Lake control structure except during the Minimum Flow Study outlined in clause 26 of this licence.

22. A minimum instantaneous flow of 0.6 m^3/s shall be discharged out of Head Pond #2 from December to April.

Operations, Maintenance and Surveillance Manual

23. No later than December 1, 2011, the Licensee shall submit to the Board an updated Operations, Maintenance and Surveillance Manual covering the facilities authorized by this licence and incorporating the conditions outlined in this licence. The manual shall include at a minimum, but not necessarily limited to, the following:

    a) operating procedures during normal and flood events;

    b) seasonal operating procedures;

    c) seasonal and annual maintenance requirements and procedures;

    d) details of the specific operational protocols/water management strategies utilized to ensure the operation of the systems in a manner that avoids exceedance of the full supply level at Fish Lake;

e) procedures for implementing and reporting on any special maintenance recommendations;

f) protocols for routine and non-routine inspections of all facilities, including timing, monitoring locations, information to be collected and methods to be used that meet the Licensee's corporate requirements, the requirements of the then most current version of the Dam Safety Guidelines, and any other regulatory requirements, including those contained in this licence;

g) reporting requirements; and

h) policies and procedures for the implementation of dam safety reviews as recommended by the Dam Safety Guidelines.

Dam Safety Implementation

24. No later than December 1, 2011, the Licensee shall submit to the Board, an implementation report covering the recommendations contained in the *Fish Lake Hydro 2010 Dam Safety Report*, as submitted in exhibit 1.2.4 of the Application. The report shall address both short term and long term implementation requirements and the integration of those requirements into the findings of the Resource Optimization Study and future facility modifications. Short term requirements are those that are to be implemented during the term of this licence. Long term requirements are those that are proposed to be implemented beyond the term of this licence.

Resource Optimization Study

25. The Licensee shall submit to the Board, an updated Resource Optimization Study no later than September 1, 2012. The Resource Optimization Study shall include at a minimum, but not necessarily be limited to:

a) an assessment and evaluation of the storage requirements on Fish Lake and Louise Lake;

b) identification of impacts, including those caused by inundation and wave action to Settlement Land, privately owned land, public trails and public use areas including beaches, around Fish Lake, Louise Lake and Franklin Lake; and

c) the ecology of any water bodies impacted by the facilities authorized by this licence.

Minimum Flow Study

26. No later than September 1, 2012, the Licensee shall submit to the Board, the results of the ongoing study of the impacts of low flows on fish and fish habitat. In particular, the study shall at a minimum, but not necessarily be limited to:

    a) the recommended minimum flows to mitigate the identified impacts; and
    b) mitigation addressing the minimum flows for both Fish Lake and Louise Lake control structures.

Shoreline Erosion

27. No later than September 1, 2012, the Licensee shall submit to the Board, the results of the shoreline erosion study investigating the impacts of the operation of the facility on shoreline erosion at Fish Lake and Louise Lake Lake, including erosion due to inundation and wave action. Options for erosion protection or mitigation shall be developed and included in the study.

Louise Lake Minimum Supply Level

28. No later than September 1, 2012, the Licensee shall submit to the Board, the results of the investigation on the minimum supply levels for Louise Lake necessary to maintain fish habitat.

Franklin Lake Study

29. No later than September 1, 2012, the Licensee shall submit to the Board, the results of the study of the impacts of the operation of the facility on Franklin Lake and the Jackson Creek watershed including impacts on lake water levels, watershed hydrology and fish habitat.

Nesting Bird Study

30. No later than September 1, 2012, the Licensee shall submit to the Board, the results of the ongoing study of nesting birds at Fish Lake and Louise Lake including an assessment of the impacts of the operation of the facility.

Louise Lake Auxiliary Spillway

31. No later than September 1, 2012, the Licensee shall submit to the Board, a plan for the improvement of water conveyance facilities for the auxiliary discharge from Louise Lake to Franklin Lake and the management of water levels in Franklin Lake affected by the auxiliary discharge.

Fish Stranding/Ramping Protocols

32. No later than December 1, 2011, the Licensee shall submit to the Board, Ramping protocols for the spillway channels, including the spillway channels for Ditch #3, Ditch #1, Pond #2 and Louise Lake, to minimize the potential for fish stranding during diversion events. Fish salvage program plans which will be utilized where Ramping is not effective, shall be included in the Ramping protocol.

33. No later than September 1, 2012, the Licensee shall submit the results of an investigation of the potential for fish stranding in the Head Pond No. 2 spillway channel.

Timelines for 25-Year Application

34. No later than December 31, 2011, the Licensee shall submit to the Board, a plan for the upcoming 25-Year licence application including timelines to allow for the Board's public process of the application, prior to the expiration of Water Use Licence HY10-083.

Decommissioning Plan

35. Subject to any required assessments, authorizations or approvals, the Licensee shall implement the Decommissioning Plan.

PART D - MONITORING

36. All works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

37. Annually, the Licensee shall carry out an inspection of all water management structures authorized by this licence. The inspection shall be carried out by a qualified professional engineer licenced to practice in Yukon, and shall follow the recommendations contained Dam Safety Guidelines. The findings of the inspection shall be submitted as part of the annual report.

38. The Licensee shall monitor fish stranding during diversion events in spillway channels and monitor the effectiveness of Ramping, fish salvages and/or other means of reducing fish stranding. The findings of this monitoring shall be submitted as part of the annual report.

NORTHLAND EARTH & WATER CONSULTING INC.

2012 Dam Safety Report
Fish Lake Hydro System
Whitehorse, Yukon

Prepared for

The Yukon Electrical Company Ltd.

December 2012

Reference: 2010-01

NORTHLAND EARTH & WATER CONSULTING INC.

12 Aquamarine Place, Whitehorse, Yukon Y1A 6G8

December 4, 2012

The Yukon Electrical Company Ltd.
100 – 1100 1st Avenue
Whitehorse, Yukon Y1A 3T4

Attention: Mr. Brock Coulthard

Dear Brock,

Re: 2012 Dam Safety Report
Fish Lake Hydro, Whitehorse, Yukon

Please find attached the 2012 Dam Safety Report for Fish Lake Hydro that details Northland Earth & Water Consulting Inc.'s (Northland) observations and recommendations arising from site visits to the Fish Lake Hydro facilities completed in 2012 and from reviewing documentation related to dam safety activities undertaken in 2012.

Northland thanks you for the opportunity to be of service; should you require any further assistance with this project or other water resources projects please do not hesitate to contact the undersigned at your convenience.

Yours truly,

Cord Hamilton, M.Eng., P.Eng.
Civil Engineering Consultant
Ph: (867) 332-6556
Email: chamilton@Northlandconsulting.ca

1. Introduction

As requested by The Yukon Electrical Company Ltd. (Yukon Electrical), Mr. Cord Hamilton, P.Eng. of Northland Earth & Water Consulting Inc. (Northland) completed a series of site visits in 2012 to observe water management structures associated with the Fish Lake Hydro system near Whitehorse, Yukon. Specifically, the following structures were observed on one or more occasions:

- Fish Lake Dyke;
- Ditch #3;
- Louise Lake Containment Dyke;
- Louise Lake Auxiliary Spillway;
- Louise Lake Control Structure;
- Ditch #1;
- Ditch #1 Spillway; and
- Pond #2 and its dam and discharge structures.

Northland's site visits were completed to observe the condition and performance of the water management structures in relation to dam safety requirements and in relation to past condition assessments such as the 2007 Dam Safety Review completed by Hatch Energy Ltd.

In addition to the site visits, Northland has also reviewed the following additional information related to some or all of the above water management structures:

- Video camera survey of the Dam #2 Low Level outlet pipe;
- Flow capacity determinations for the Louise Lake Auxiliary spillway and the Headpond #3 spillway; and
- A preliminary design for the Ditch #3 Spillway to Franklin Lake.

In addition to these specific sources of additional information, Northland has also consulted with Yukon Electrical staff regarding various dam safety and related maintenance activities conducted in 2012. Finally, as part of the 2012 dam safety program Northland has completed a review of the passage of the inflow design flood (IDF) for the system below Fish Lake as was recommended in the 2011 Dam Safety Report

Observations and recommendations from Northland's site visits and reviews of relevant information are presented in the following sections of this report.

2. Overview of 2012

Based on observations and review of dam safety activities, Northland can state that in 2012 progress has been made on the inventory of potential or actual dam safety deficiencies and non-conformances documented in the 2011 Dam Safety Report and that planning to address remaining or new issues is appropriate and correctly aligned with the significance of those issues.

Entering into 2012, the Fish Lake Hydro system had an inventory of 21 dam safety related recommendations carried forward from the 2011 Dam Safety Report. This included a few remaining recommendations from the 2007 Dam Safety Review and subsequence recommendations from the period of 2008 to 2011 inclusive. During 2012, ten of these existing recommendations have been discharged or superseded and 15 new recommendations have been identified.

With respect to the discharged recommendations, the most significant recommendations that was addressed in 2012 was the re-assessment of the passage of the IDF for current and proposed future operating conditions for infrastructure located downstream of Fish Lake.

In regards to the new recommendations, only three of the new recommendations are considered significant with the remainder being of a minor nature. Most of the new recommendations are expected to be addressed by end of 2013. The three significant recommendations include moving forward with at least a temporary risk management plan for the Louise Lake containment dyke, completing planned maintenance of the Headpond #2 spillway, and completing Ditch #3 upgrades in conjunction with Fish Lake Dyke Upgrades to ensure appropriate passage of the IDF under the proposed long term operation conditions.

For reference, a consolidated list of the active recommendations arising from the 2012 observations, as well as from past reviews is presented in Table A1 in Appendix A. Past recommendations that have been addressed or superseded are presented in Table A2, also in Appendix A.

In regards to significant events from 2012, Northland notes that the Fish Lake Hydro system continued to experience usual operating conditions. Throughout 2012, Plant #1 remained out of service due to failure of the hydro unit in March 2010. This led to the need to utilize the Ditch #1 spillway to a greater extent than normal.

In addition concerns regarding fish stranding required that the Louise Lake auxiliary spillway remain in operation for the complete winter of 2011/12 and Plant #2 was out of service for several months to accommodate upgrades to the building, transformers, and valves in summer 2012. During the shutdown of Plant #2 bypass flows were routed into the Dam #2 spillway.

Specific comment on the condition, performance and any completed dam safety activities for individual components of the Fish Lake hydro system are presented in sections 3 to 10. New recommendations arising from the inspections and review of additional information are also detailed in sections 3 to 10. The results of the IDF passage re-assessment is presented in section 11.

Photographs of water retaining structures observed in 2012 are presented in Photographs section following this report.

3. Fish Lake Dyke

3.1 Observations

Northland observed the Fish Lake dyke on September 12, 2012. There was no notable change in the condition of the structure in relation to the period of 2007 to 2011. Existing physical issues with the structure include displaced upstream riprap, a narrow crest, over-steepened upstream slopes and insufficient freeboard (for the IDF condition) for a low area near the western end of the dyke. In addition, the upstream and downstream slopes have willow and shrub growth that requires removal.

The discharge culvert, trash rack, and gate were in working order. As reported in past inspections, the exposed portion of the discharge culvert downstream of the dyke has a hole at the crown of the culvert that does not affect its performance but may be a hazard to the public.

3.2 Additional Information

The preliminary design for upgrading the structure has been completed and will be submitted for regulatory approval in fall 2012. Pending regulatory approval upgrading works will be initiated in 2013 and completed in 2014.

3.3 Recommendations

On the basis of observations, additional information reviewed in 2012, and on the current planning of Yukon Electrical, Northland has no new recommendation in regards to the Fish Lake dyke.

There were three pre-existing recommendations related to the Fish Lake dyke. These three recommendations, which are listed in Table 1, all relate to the pending upgrading activities currently scheduled for 2013 to 2014. Northland is supportive of this timeframe for addressing those recommendations.

Table 1: Pre-existing Fish Lake Dyke Recommendations

#	**Recommendation**
2008-04	Previously planned construction to add riprap, to increase width and height of the dyke and to add an emergency spillway should be updated and completed.
2008-06	Extend the staff gauge to the new dyke crest level, and check the staff gauge against a known stable bench mark for elevation.
2008-07	Cut all existing trees and shrubs that are growing on the existing dyke.

4. Ditch #3

4.1 Observations

On September 12, 2012, Northland completed a full walking inspection of the Ditch #3 channel from its inlet at Fish Creek to the control structure (drop box) at its northern end. On November 2, 2012, a second site visit was completed to observe the dyke following vegetation removal completed in October, 2012.

During the visits no visual evidence of significant slope distress or down slope seepage at any location along the dyke was observed. As in the past minor slumping or erosion scars on the upstream face of the containment dyke were observed at some locations; however, such features were shallow, and did not appear to be recent.

During the September 2012 site visit, the dyke crest and slopes were densely covered in vegetation (willows, etc.). The standing vegetation had previously been removed from the crest and upstream face in 2009; however, this has extensively re-established itself and requires removal. The presence of the vegetation limited visibility of the dyke crest and slopes in many locations.

During the November 2012 site visit it was confirmed that clearing of the vegetation along the water side face and crest of the dyke had been completed during October 2012. Clearing of the vegetation had also been completed for roughly 30% of the downslope face of the dyke.

An animal burrow complex, possibly made by muskrats or otters, was discovered roughly 80 m upstream of the Drop Box inlet on the canal side of the Ditch #3 dyke. The burrows appeared to include shallow tunnels running both parallel and perpendicular to the canal, starting on the water side of the dyke.

During the November 2012 site visit it was possible to better observe the area of the burrows. It was observed that the location of the burrows was a relatively low and narrow portion of the dyke.

The Ditch #3 Drop Box control structure was also observed and found to be in fair condition. The repair work completed in 2011 to fill erosion along the joint between the left-hand-side chute wall and the chute base slab could not be observed by Northland due to flows in the structure. At the exit of the chute it appears that some erosion may be occurring at the base of the left-hand-wall where the wall flares open into the flip bucket. This potential erosion could not be examined in detail due to flows in the structure. The chute wall was observed to be sound with no visible cracking or deformation. There was no visible seepage through the fill soils on the exterior side of the chute wall.

4.2 Additional Information

As noted, Yukon Electrical has completed vegetation removal along the entire channel side face and the crest of the dyke. Vegetation removal was also completed for roughly 30% of the downstream slope. It is understood that the remainder of the downstream slope will have vegetation removed in 2013.

Also following the September site visit, the insulation and cover box for the Ditch #3 Drop Box was reconstructed and new stoplogs fabricated and installed. This work also included cutting the projecting metal stoplogs guides so that they do not extend above the insulation. This was intended to reduce thermal conductivity which may reduce potential ice build-up inside the drop box in the winter months.

Yukon Electrical was able to inspect the chute while installing winter stoplogs into the structure and provided photographs of the chute which show the repairs to the joints at the chute slab and wall interface are in good condition. Yukon Electrical could not fully examine the potential erosion at the base of the chute where it flares out into the flip bucket because even at low flow water pools at this location. Nevertheless, Yukon Electrical staff indicated that it did not appear to be significant.

In regards to future planning related to Ditch #3, Yukon Electrical has elected to complete several upgrades to Ditch #3 as part of upgrading the system for proposed operations under a long term water use licence. The proposed upgrades include the following:

- Re-establishment of a control structure leading into the Ditch #3 Diversion to Franklin Lake.
- Construction of a parallel spillway beside the existing Drop Box to add capacity to Ditch #3 for flows to Louise Lake. This upgrade is planned to add overflow capacity during the ice on season when ice jams or blockages in the Ditch #3 Drop Box can lead to reduced capacity and temporary surcharging in Ditch #3.
- Raising the crest level of low areas along the Ditch #3 dyke to ensure that crest elevation of at least 1031.0 m is present along the complete length of the Ditch #3 Dyke. This upgrade will provide greater safety during both the ice on and the open water season.

The proposed upgrades are currently scheduled to be completed by 2014 pending regulatory approvals.

4.3 Recommendations

On the basis of observations, additional information reviewed in 2012, and on the current planning of Yukon Electrical, Northland has two new recommendations in relation to Ditch #3:

(1) Annual monitor the potential erosion at the left hand side of the chute wall of the Ditch #3 Drop Box at its exit into the flip bucket.

(2) In spring 2013, investigate the extent of the animal burrows roughly 80 m upstream of the Drop Box, expose, and infill the burrows with low permeability soils.

With respect to pre-existing recommendations, Northland notes that there were two pre-existing recommendations related to Ditch #3 and its control structure. These recommendations are presented in Table 2.

Table 2: Pre-existing Ditch #3 Recommendations

#	**Recommendation**
2008-10	Cut all existing trees and shrubs on crest and upstream/downstream faces of the embankment.
2011-03	As proposed upgrading of the Fish Lake dyke will lead to higher freshet discharges routinely being passed downstream into Ditch #3, the ability of Ditch #3 to pass these routine flows as well as the inflow design flood from Fish Lake should be evaluated.

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) As noted the standing trees and shrubs on channel side face of the dyke and the crest of the dyke were removed in October 2012. Roughly 30% of the downslope side of the dyke was also cleared of standing vegetation. Yukon Electrical has indicated the remainder of the work will be completed in 2013.

(2) As will be discussed in section 11 of this report, Yukon Electrical has completed planning for management of the higher inflow design flood flows that will be associated with the upstream Fish Lake Dyke Upgrades. Recommendations arising from this planning and from the review of the passage of the IDF are presented in section 11.

Therefore, Northland concludes that previous recommendation 2008-10 has been partially addressed and recommendation 2011-03 has been resolved. The proposed timeline to fully discharge recommendation 2008-10 is acceptable to Northland.

5. Louise Lake Containment Dyke

5.1 Observations

The Louise Lake containment dyke was observed on September 12, 2012 and on November 2, 2012 following removal of trees from the structure. The condition was consistent with past observations from 2007 to 2011. The animal burrows observed in 2011 were still present but no further collapse of the burrows was observed.

During the September 2012 visit Northland observed that evidence of beaver activity remains abundant in the area and on the dyke. A beaver lodge is located in Louise Lake just north of the end of the dyke.

In addition active harvesting of mature trees on the downstream slope of the dyke was observed. Finally very well defined paths from beavers dragging felled trees from the downstream slope up to Louise Lake are present at three locations along the dyke.

As in past site visits, the dyke was observed to be steep with sections of the downstream slope exhibiting revelling of coarser material if subjected to foot traffic. Other than revelling of surficial materials on the steep downstream slope no evidence of slope distress or movement was observed.

Seepage through the dyke and into a well-defined seepage pond at the toe of the dyke was observed consistent with past inspections. Sporadic to extensive tree growth on the upstream and downstream slopes was still present in September 2012 but was removed in October 2012 as confirmed during the November 2012 site visit.

5.2 Additional Information

Evaluation of the static and seismic stability of the containment dyke has been completed by EBA Engineering Consulting Ltd. (EBA). EBA has found that two of the three trial sections analyzed do not meet the minimum factor of safety guidelines for new structures in the 2007 Canadian Dam Association Guidelines. While the static stability of the structure can be considered to be acceptable given the 50 plus years of satisfactory performance, the seismic stability guidelines cannot be shown to be acceptable at this time. EBA provided three options to address this finding:

1. "Do Nothing" – In this context "do nothing" infers not completing physical upgrades to the structure or further investigation related to the potential physical stability issues. However, it also infers that a risk assessment would be completed to determine how the structure could be managed to maintain the consequences of a physical failure within socially acceptable limits. As previously identified in the 2010 and 2011 dam safety reports, failure of the dyke has limited environmental and economic consequences as flooding of the depression on the downstream side of the dyke is contained to a small area and does not result in a significant drop in the level of Louise Lake. Thus, to be viable this option would require risk management of the structure to ensure that the risk to the public is at an acceptable level.

   At a minimum it is expected that risk management would entail controlling access to the dyke crest with secured gates at both ends to minimize the risk to the public and a Public Safety Management System might be required to deter any members of the public using the dam crest for recreational or other purposes;

2. Commission a more rigorous in-situ testing and analysis program –The seismic analysis conducted by EBA is believed to be conservative, provided the foundation and fill soils are non-liquefiable. An assessment of in-situ dynamic deformation parameters, as well as a liquefaction screening exercise, combined with a more rigorous deformation analysis, may result in the estimated seismic deformations being less than predicted; hence, the seismic stability may be found to be adequate such that uncontrolled discharge resulting from seismic induced deformations is viewed to be unlikely; or

3. Construct a Downstream Buttress - a buttress of the dyke could be constructed to ensure that the static and seismic stability of the dyke fully meet current CDA guidelines for new structures.

At this time it is understood that Yukon Electrical is evaluating whether to implement the "do nothing" risk management approach or the construction of a downstream buttress.

In addition to the EBA information, Northland has also been advised that a cabin located on the north side of the containment dyke is now occupied on a full time basis with the occupant utilizing the dyke as an access road to this residence. This development should be accounted for in any hazard or risk management assessment that is conducted by Yukon Electrical.

Finally, Northland understands that if Yukon Electrical elects to construct a buttress to improve the static and seismic stability of the dyke, this work would be deferred until re-construction of the Ditch #3 diversion (spillway) to Franklin Lake which is expected to occur in 2014.

5.3 Recommendations

On the basis of observations, additional information reviewed in 2012, and on the current planning of Yukon Electrical, Northland has two new recommendations in regards to the Louise Lake Containment dyke:

(1) In summer 2013, expose and infill animal burrows located on the upstream face of the dyke.

(2) By end of spring 2013, establish and implement, at least temporarily, a public safety risk management plan for the dyke and maintain the program until upgrading of the dyke is completed or permanently if physical upgrading (lowering the slope or constructing a buttress) is not undertaken.

With respect to pre-existing recommendations, Northland notes that there were four pre-existing recommendations related to the Louise Lake Containment Dyke. These four recommendations are presented in Table 3.

Table 3: Pre-existing Louise Lake Containment Dyke Recommendations

#	**Recommendation**
2008-14	Carry out a geotechnical investigation to confirm the dyke fill and foundation materials and then analyze seepage and slope stability of the dyke.
2010-04	Complete assessment and planning for any upgrades to this structure
2011-07	Existing vegetation growth on the structure should be removed.
2012-02	Monitor the minor depressions observed on the dyke in 2011 and determined if further investigation is warranted.

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) The analysis has been received and accepted by Yukon Electrical.

(2) With respect to completing the assessment and planning for any upgrades for this structure, those activities are on-going and Northland recommends that Yukon Electrical should endeavour to complete this assessment by the end of spring 2013 in conjunction with the planning for implementation of a public safety risk management plan.

(3) Clearing of the tree cover from the dyke has been completed by Yukon Electrical; therefore, this recommendation has been addressed.

(4) Northland believes that the minor depressions are appropriately attributed to animal burrowing or animal disturbances (moving felled trees) and therefore further investigation is not warranted. As noted it is now recommended that these depressions on the upstream side of the dam be exposed and filled.

Therefore, recommendations 2008-14, 2011-07, and 2012-02 has been addressed or appropriately superseded. Recommendations 2010-04 is still in progress and Northland has suggested that this recommendation be resolved by end of spring 2013.

6. Louise Lake Auxiliary Spillway

6.1 Observations

The auxiliary spillway was observed on September 12, 2012 and again on November 2, 2012. During the September site visit the structure was in use with all stoplogs removed. The structure appeared to be in fair condition.

During the November site visit, seven stoplogs were in place and only a minor seepage/leakage flow was entering the flume section of the structure downstream of the stoplogs. With the low flow it could be observed that some seepage is upwelling into the flume through some joints in the floor boards and that the PWF lumber that has been below the water line for extensive periods is starting to show aging and wear. Flow through the structure has resulted in the deposition of some granular materials (cobbles, gravel and sand) over the flume floor near the downstream end of the flume.

6.2 Additional Information

A survey of the auxiliary spillway structure was completed in June 2012 to confirm elevations of the structure as necessary to evaluate its flow capacity and to complete a review of the IDF passage through Louise Lake. This survey was reviewed by Northland. On the basis of this survey and other field measurements, it is estimated that the auxiliary spillway and its embankment has a maximum containment elevation of 1015.46 m. Overtopping of narrow, low portions of the embankment immediately adjacent to the spillway flume may occur starting above this elevation.

Remote monitoring of water levels at the auxiliary spillway was established in summer 2012. The monitoring station is linked to Yukon Electrical's SCADA system and can be read in real time by Yukon Electrical staff at the Marwell office centre.

Yukon Electrical has commissioned the development of a stage discharge relationship for this structure but it is not yet finalized. It is anticipated prior to the end of 2012. At this time Northland has been advised that the capacity of the auxiliary spillway has been determined to be 7.9 m^3/s with no freeboard (Louise Lake elevation 1015.46 m).

6.3 Recommendations

Northland has four dam safety related recommendations in relation to the Louise Lake Auxiliary spillway and there are no previous or outstanding recommendations in relation to this structure. The recommendations are:

(1) Confirm the capacity and stage discharge relationship of the auxiliary structure.

(2) In summer 2013, evaluate potential piping that may be occurring underneath the timber floor of the spillway flume.

(3) In summer 2013, obtain some specific measurements of the quality of the PWF timber within the flume. Some baseline measurements of the structure (width) should be made to monitor any future distortion that might develop due to degradation of the timber in the structure.

(4) In summer 2013, remove accumulated sediment from within the spillway flume and continue to do so an annual basis.

While no specific existing recommendations were outstanding for the auxiliary spillway, the general recommendation to re-assess the passage of the IDF through Louise Lake includes consideration of this structure. This re-assessment is addressed in section 11 of this report.

7. Louise Lake Control Structure

7.1 Observations

The control structure was observed on September 12, 2012. The structure, which was fully refurbished in 2011, was observed to be in good condition. One tree on the right-hand-side of the structure is still pending removal.

The instrumentation suite established in 2011 is fully operational and a stage discharge relationship has been established for the downstream sensor to allow for real time flow measurement independent of any gate opening relationship.

7.2 Additional Information

An updated as-built drawing has been prepared by Yukon Electrical to include observations made during the refurbishment work completed in 2011.

7.3 Recommendations

In regards to recommendations for this structure, Northland has no new recommendations. In regards to pre-existing recommendations, there were two pre-existing recommendations for this structure. The recommendations are presented in Table 4.

Table 4: Pre-existing Recommendations Louise Lake Control Structure

#	**Recommendation**
2012-03	Remove remaining tree located on the structure
2012-04	Complete as-built plans of the refurbished structure

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) In regards to the remaining tree located just upstream of the structure, Yukon Electrical is discussing the removal of the tree with local residents and will remove the tree in 2013.
(2) In regards to the as-built plans, Yukon Electrical has transferred field observations from the refurbishment work in 2011 onto the original design drawing. This revised drawing serves as the as-built for the structure. Therefore, this recommendation has been addressed.

Therefore recommendation 2012-04 has been discharged. With respect to recommendation 2012-03, Northland is supportive of the proposed timeline to address this recommendation.

Finally, as with other elements of the Fish Lake system, the general recommendation to re-assess the passage of the IDF passage includes consideration of this structure. This re-assessment is addressed in section 11 of this report.

8. Ditch #1

8.1 Observations

Northland completed a visit to Ditch #1 on September 12, 2012 to observe the performance of the dyke, spillway, and intake structure. The condition of upstream slope of the Ditch #1 dyke was observed to be consistent with past inspections. This slope exhibits signs of shallow slope movements likely due to solifluction.

Solifluction is a type of shallow slope movement where a saturated soil layer moves slowly downslope, over impermeable material. It occurs in cold regions where melting of seasonal frost during the spring thaw leads to a weak saturated layer overlying stronger and/or unthawed materials. The weak layer then has a tendency to creep downslope opening tension cracks along the slope.

For Ditch #1 tension cracks are visible in a number of locations along the upstream face of the containment dyke and are located between the crest and the normal water level of the Ditch. The observed solifluction movements are not a concern regarding the performance of the dyke.

In addition to solifluction movement some animal burrows have also been observed along the containment dyke. Where observed the burrows are located on very wide sections of dyke and are not considered to represent a hazard.

8.2 Additional Information

In 2012, Yukon Electrical commissioned an as-built survey of Ditch #1. The survey was completed and the drawing is currently under development with the expectation it will be finalized prior to the end of 2012.

Also in 2012, Yukon Electrical completed the commissioning of a remote monitoring station that was installed at the intake structure in 2011. The station allows for real time remote monitoring of canal levels.

8.3 Recommendations

On the basis of observations in 2012, and on the current planning of Yukon Electrical, Northland has no new recommendations in regards to the Ditch #1 and its intake structure. The general recommendation to re-assessing the passage of the inflow design flood includes consideration of Ditch #1 and this is discussed in section 11.

With respect to pre-existing recommendations, Northland notes that there were three pre-existing recommendations for Ditch #1, its intake structure and penstock. These recommendations are presented in Table 5.

Table 5: Pre-existing Recommendations for Ditch #1

#	Recommendation
2011-09	An as-built survey drawing of the Ditch #1 channel and containment dyke should be produced and the minimum freeboard level identified for tying into remote monitoring activities.
2011-10	Establish remote monitoring of the water level in Ditch #1.
2011-11	An assessment of the stability of the penstock between the intake structure and Powerhouse #1 should be completed with the assumption that no ground anchors are present along the pipeline.

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) An as-built survey of the dyke has been completed and the drawing is in production with the expectation it will be completed prior to the end of 2012. Once completed the minimum crest elevation will be provided for tying in an alarm level with the remote monitoring station.

(2) Remote communication with instrumentation at the intake building has been established and is now part of the Yukon Electrical SCADA system.

(3) The assessment of the penstock stability has not yet been completed. This is a low priority item and Yukon Electrical intended to complete this work by 2016.

Therefore, recommendation 2011-10 has been addressed, recommendation 2011-09 is expected to be addressed prior to year end 2012, and recommendation 2011-11 is still scheduled for completion prior to 2016.

9. Ditch #1 Spillway

9.1 Observations

The Ditch #1 spillway reconstruction was completed in 2011. The new spillway, which is located in same location as the former spillway, is a culvert with a concrete headwall. The headwall includes stoplog guides and an adjustable stoplog weir allowing for improved control of discharges into the spillway.

During the site visit in September 2012 Northland observed the previously identified seepage at the base of the dyke near the spillway exit. The seepage appears to be normal groundwater seepage from the upstream Ditch #1 channel that surfaces into the former channel of Porter Creek that runs along the toe of the Ditch #1 dyke from the exit of the spillway to the upstream limit of Ditch #1. All seepage was observed to be clear and Northland does not consider the seepage to be of concern.

The spillway was active during the site visit and has been used extensively throughout 2012 due to the failure Plant #1 in 2010. It was observed that some debris has accumulated in front of the spillway (cobbles and other coarse sediment) and some debris is accumulating on downstream of the exit (branches and other woody debris).

9.2 Additional Information

In 2012, Yukon Electrical had a full stage discharge relationship developed for the operation of the Ditch #1 spillway. The relationship allows for determination of the expected range of flows through the spillway based on the number of stoplogs present and the canal level during the ice free season. Observation of the spillway operation in the ice on season has shown that a direct relationship between canal level and flow through the spillway cannot be made due to the complications with the flow hydraulics underneath the ice cover in the canal and in front of the spillway inlet.

Given the issue of flow prediction in winter conditions, Yukon Electrical has informed Northland that it is now planned to add a remote monitoring station upstream of the Ditch #1 spillway to monitor inflows to Ditch #1 in advance of flow potentially passing into the spillway. As a result of this planning the need for a staff gauge to assist in monitoring flows through the spillway is no longer required.

Yukon Electrical has indicated that the new station will be installed in summer 2013. Comparison of flows from this new station and the existing station at the Ditch #1 intake structure will allow for a determination of flows diverted into the Ditch #1 spillway.

9.3 Recommendations

On the basis of observations, additional information reviewed in 2011, and on the current planning of Yukon Electrical, Northland has two new recommendations in regards to the Ditch #1 spillway:

(1) Install a remote monitoring station to monitor inflows into Ditch #1 upstream of the Ditch #1 spillway.

(2) Annually prior to the on-set of the freshet remove accumulated debris from the inlet and exit of the spillway to ensure that the full capacity of the structure is available, if required, to discharge the freshet. This recommendation should be incorporated into the OMS manual.

With respect to pre-existing recommendations, Northland notes that there were two pre-existing recommendations related to the Ditch #1 spillway. These recommendations are presented in Table 6.

Table 6: Pre-existing Recommendations Ditch #1 Spillway

#	**Recommendation**
2012-05	Establish a geodetic referenced staff gauge at the structure to facilitate observation of water levels at the structure.
2011-13	Develop as-built drawings and operational protocols for use of the spillway.

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) As noted in section 9.2, Yukon Electrical has determined that a staff gauge is not the appropriate means of monitoring flow into the Ditch #1 spillway and has decided to install a full remote monitoring station upstream of the Ditch #1 inlet for this purpose. Therefore, a staff gauge is not required at the spillway and this recommendation has been superseded.

(2) Operational protocols for use of the spillway in the form of stage discharge relationships for the spillway have been completed. The as-built plans for the spillway are still in development.

Therefore, recommendation 2012-05 has been superseded and recommendation 2011-13 has been partially discharged with full completion expected by end of 2012.

As with other elements of the Fish Lake system, the general recommendation to re-assess the passage of the inflow design flood includes consideration of this structure. This re-assessment is addressed in section 11 of this report.

10. Pond #2

10.1 Observations

Pond #2, its dam and discharge structures were observed by Northland on September 12, 2012 and on November 2, 2012. The condition of Pond #2 was observed to be consistent with 2011 except that additional brushing of the upstream side of the dam was completed in October 2012, and additional removal of debris and trees from the spillway channel downstream of the dam had been completed.

Finally, in October 2012, the elevation of the crest road from the spillway bridge to the south abutment of the dam was raised by placing and compacting as much as 0.3 m of road fill.

In addition to the site visit observations, Northland reviewed a video of a camera inspection of the low level outlet pipe that was completed in 2012. The recording of the inspection revealed that the low level pipe is in good condition with no obstructions or significant distortions visible. No evidence of excessive corrosion or of potential rupture of the pipe was seen. Debris near the exit of the pipe that was observed in a partial inspection in 2011 appears to be rocks thrown into the exit of pipe and not from collapse of the pipe.

10.2 Additional Information

In May 2012, Yukon Electrical completed a crest survey of the dam to confirm its elevation. The survey revealed that the dam was not built to the design elevation of 797.97 m, as the minimum crest elevation was found to be 797.33 m.

As a result of this finding, it was determined that the freeboard requirement for the dam was not being met under all operational conditions. Freeboard requirements were determined in 2007 by Hatch and set at 0.16 m for normal operations and 0.14 m for passage of IDF. The existing Full Supply Level (FSL) of 797.0 m allows for the freeboard required for normal operations. However, during flood events or unplanned plant outages surcharging of the reservoir can occur above the FSL level. Records of Pond #2 levels indicate that the freeboard requirement for unusual operations (0.14 m) was not met in roughly 1.2% of the days of historical operations (1995 to present).

Given this information, Yukon Electrical modified its operations in 2012 by removing stoplogs to lower the inlet to the overflow spillway and maintaining the reservoir at a lower elevation to ensure that the freeboard requirement was achieved.

Moreover, to ensure that the freeboard requirement can be achieved during large flood events, significant freshet peaks, inflow surges from intense rain storms, or unplanned plant outages, Yukon Electrical built-up the elevation of the access road across the crest of the dam in October 2012 with a goal of elevation 797.60 m. An as-built survey of the raised crest and other features of Dam #2 was completed in October 2012 and found that a minimum crest elevation of 797.57 m was achieved.

In addition to the raising of the crest road height, Yukon Electrical had also intended to complete some maintenance to the overflow spillway in 2012. It was intended to remove some of the accumulated sediment that has built up in front of the spillway entrance. This would improve the easy with which stoplogs can be removed. Currently stoplogs can be removed by hand down to elevation 796.53 m (average elevation across the slightly sloping stoplogs). Below this elevation equipment will be required due to the presence of the accumulated sediment in front of the lower stoplogs.

Yukon Electrical had also intended to complete some repairs to the concrete walls of the spillway. Both the removal of the sediments and the concrete repairs could not be completed due to extended downtime of Plant #2 during its annual maintenance shutdown and they are now scheduled for 2013.

Finally, Yukon Electrical commissioned and received a stage discharge relationship for the spillway to assist in the re-assessment of the IDF and in planning for water management under normal and plant upset conditions. Northland notes if repairs to the concrete walls result in the spillway channel becoming narrower, the determined capacity of the spillway could be impacted. In addition, the removal of the current sediments in front of the spillway is necessary to confirm the assumed hydraulics conditions for the spillway for the case where all stoplogs are removed (i.e. the maximum spillway capacity).

Key findings of the stage discharge relationship are presented in Table 7.

Table 7: Estimated Discharge Capacity of Dam #2 Spillway

Pond Elevation (m)	Stoplog Elevation (m)[1]	Estimated Discharge (m^3/s)	Comment
797.00	796.83	0.38	Current FSL and seven stoplogs in place
797.18	796.83	1.08	Proposed long term FSL and seven stoplogs in place
797.43	796.83	2.40	Maximum reservoir elevation with required freeboard and seven stoplogs in place.
797.43	795.85	10.18	Maximum reservoir elevation with required freeboard and no stoplogs in the spillway.

Based on the capacities identified in Table 7, the spillway with the current average stoplog elevation of 796.83 m is sufficient to pass normal Head Pond #2 inflows through the spillway if a plant upset occurs at maximum plant flow while at either the current or proposed FSL levels. Also based on Table 7, the maximum capacity of spillway with all stoplogs removed is currently estimated to be 10.18 m^3/s.

10.3 Recommendations

On the basis of observations, additional information reviewed in 2012, and on the current planning of Yukon Electrical, Northland has two new recommendations in regards to the Pond #2. The new recommendations are as follows:

(1) Complete planned spillway maintenance in 2013 and reconfirm the spillway capacity following the maintenance activities.

(2) Until the spillway maintenance is completed, make contingency provisions for the use of excavation equipment to remove stoplogs below elevation 796.53 m should it be required for passage of flood flows and include the planning provisions in the OMS manual.

With respect to pre-existing recommendations, Northland notes that there were four pre-existing recommendations related to Pond #2, its dam and discharge structures. These recommendations are presented in Table 8.

[1] Stoplog elevation presented is the average elevation of the sloping stoplogs.

Table 8: Pre-existing Pond #2 Recommendations

#	**Recommendation**
2008-28	Repair freeze thaw damage to concrete components of spillway.
2008-32	Prepare a written procedure for dewatering and re-watering penstock #2
2008-34	Repair Freeze thaw concrete damage to intake structure.
2010-10	Complete an assessment of the low level outlet pipe to determine if it can be abandoned

On the basis of current observations and additional information Northland comments as follows on these pre-existing recommendations:

(1) Repair of minor freeze thaw damage to spillway concrete is scheduled to be completed prior to 2015 and is currently planned for 2013. This recommendation is now superseded by the new spillway maintenance and capacity recommendation.

(2) The penstock dewatering procedure has been drafted and will be added to the revised Operations, Maintenance and Surveillance Manual (OMS) in 2012.

(3) Repair of the minor freeze thaw damage to concrete in the intake structure is currently planned to be completed by 2015.

(4) As will be addressed in section 11, the maximum spillway capacity at Dam #2 is currently estimated to be sufficient to pass the expected IDF without the need for the low level outlet pipe. However, until the spillway maintenance is completed and the resulting capacity and any operational limitations fully confirmed, the low level outlet pipe should be maintained as a supplementary discharge structure. Moreover, the current condition of the low level pipe was found to be fair and there is no current need to decommission the pipe. The planning for the low level pipe should be re-assessed in 2013 following the assessment of the outcome of maintenance of the Dam #2 overflow spillway capacity.

Therefore, recommendation 2008-32 has been discharged, recommendation 2008-28 is superseded with the new recommendation, recommendation 2010-10 is on-going with an expected completion in 2013, and recommendation 2008-34 is still appropriately scheduled to be completed by 2015.

The assessment of the passage of the IDF through Head Pond #2 is discussed in section 11 of this report.

11. Inflow Design Flood Passage Re-Assessment

As part of the 2007 Dam Safety Review, Hatch Engineering Ltd. (Hatch) completed an assessment of the ability of Fish Lake, Louise Lake and Head Pond #2 to pass the IDF. The IDF was determined to be a 1 in 100 year return period event (Q100) based on the low consequence classification for all of the structures and reservoirs of the Fish Lake Hydro system. Hatch concluded that sufficient discharge capacity was in place at all critical locations to ensure that the IDF could be safely passed.

Since completion of the 2007 Dam Safety Review, new information has been developed regarding the potential size of the IDF and changes to operations and infrastructure have also been proposed or have occurred. As a result a recommendation from the 2011 Dam Safety Report (recommendation 2012-01) was to re-assess the passage of the IDF below Fish Lake. Passage of the IDF through Fish Lake for the current infrastructure and the proposed upgraded infrastructure was completed in 2011 and found to be adequate.

Therefore, this re-assessment is limited to the reservoirs and structures below Fish Lake. This re-assessment, completed by Northland is presented in sections 11.1 to 11.6.

11.1 General Considerations

Unlike the large Fish Lake reservoir, downstream infrastructure of the Fish Lake Hydro system has relatively limited or immaterial amounts of storage that could be used to attenuate peak inflows during a flood event. This means that, with the possible exception of Louise Lake, system components should be sized to pass the peak IDF inflow.

Therefore, re-assessment of the IDF passage requires that the peak inflow for the IDF at each of the critical locations downstream of Fish Lake be estimated and then compared to the peak discharge capacity of water control or water retaining structures present at that location.

Passage of the IDF through the system requires that the discharge capacity be equal or greater than the peak inflow anticipated during passage of the IDF.

Given the system design, concurrent releases from Fish Lake will significantly impact the determination of the peak flows in the system from Fish Lake down to Louise Lake. Below Louise Lake (on the Porter Creek side of the system) Fish lake releases will only make a minor contribution to peak flows as only minimum discharges will be released into Porter Creek during flood events.

It is not likely that peak local inflows and peak releases from Fish Lake would coincide during the passage of the IDF event. Due to differences in area, elevation, and orientation the various watersheds below Fish Lake will likely each have a different timing for the occurrence of peak local inflows during flood events. Fish Lake with its high elevation and significant storage is very likely to produce the latest peak input into the system. Regardless, in considering passage of the IDF event through the system peak inflows have conservatively been assumed to coincide.

11.2 Peak Inflows

11.2.1 Previous Estimates

With respect to peak inflows, Hatch estimated peak inflows for Louise Lake and Plant #2 as part of the 2007 Dam Safety Review. For Louise Lake the peak inflow was estimated to be 10 m^3/s and for Plant #2 the peak inflow was estimated to be 3 m^3/s. These inflows excluded releases from Fish Lake and Louise Lake that would be in addition to the determined peak inflow. . Hatch did not develop an estimate for peak inflows to Ditch #3 and Ditch #1.

Hatch did not provide details on the methodology of determining the peak inflows but the 2007 report does indicate that rainfall intensity curves, and potential drainage basin properties were considered. Moreover, it is known that Hatch did not have data from the Wolf Creek watershed to consider at the time the estimates were developed. Also, Hatch utilized an area of only 1.7 km^2 in determining the contributing local area for inflows to Headpond #2. This area value was based on incorrect mapping information present on the NTS 1:50,000 scale map sheet for the plant area. The correct inflow area for Headpond #2 is 22.5 km^2 plus the upstream area contributing to the Ditch #1 spillway.

As part of the re-construction of the Ditch #1 spillway in 2010, Northwest Hydraulic Consultants Ltd. (NHC) developed an estimate of the peak inflow to Ditch #1. NHC estimated a peak inflow of 4.0 m^3/s for Q100.

The estimate was based on a contributing area of 28 km^2 for Ditch #1, no releases from Louise Lake coincident with the peak flow, and use of a regional relationship developed with the Coal Lake gauging station in the nearby Wolf Creek watershed. For the Coal Lake station, NHC utilized 6 years of maximum instantaneous flows to develop the relationship.

NHC also utilize a second method to estimate the peak inflow. The second method was to use the "Design Flood Estimating Guidelines for the Yukon Territory" Guidebook published by the Government of Canada. This method yielded an estimate of 6.2 m^3/s for Q100 into Ditch #1. Northland has since discussed this methodology with the author of the guidelines, Mr. Rick Janowizc the Government of Yukon Hydrologist, and has been informed that use of the guideline is no longer recommended.

Finally, in 2012 as part of preliminary design work for the proposed re-establishment of the Ditch #3 spillway NHC developed an estimate of the local inflow into Ditch #3 (down to the Drop Box). The estimated peak local inflow (exclusive of releases from Fish Lake) was 4.5 m^3/s. This estimate was derived using the aforementioned Government of Canada Guidelines.

11.2.2 Current Estimates

Ideally the peak instantaneous inflows for the various sections of the Fish Lake hydro system would be derived from statistical analysis of actual measured system flows over the 60 plus years of operations. As actual system data is not available for this purpose an indirect method of estimating peak inflows is required.

Potential methods include regional analysis using Yukon gauging stations or using a single suitable proxy station (if one is available) and translating peak flows from that station to the Fish Lake watersheds by pro-rating on the basis of relative watershed areas.

For the Fish Lake hydro system the adjacent Wolf Creek basin, which has similar properties, size, and shares a common watershed divide is considered to be the most potentially representative station for use in estimating stream flow properties for the Fish Lake system.

The Wolf Creek watershed includes three gauging stations with relatively extensive datasets for small Yukon watersheds. NHC has previously used Wolf Creek data to develop the IDF for the Fish Lake reservoir and for estimating the peak flow into Ditch #1. For both those applications a relative area relationship with the Coal Lake gauging station data was utilized.

Given that the peak flow estimates of interest for this assessment are for areas located below the elevation of Coal Lake, Northland considers that it is more appropriate to consider the downstream Alaska Highway gauging station of the Wolf Creek watershed. This is also recommended as the higher Coal Lake station lacks direct measurement of instantaneous peak flows from many of the years of record that are available from Wolf Creek.

For the Alaska Highway gauging station 16 years of peak instantaneous flows and peak daily flows are available for the Alaska Highway gauging station. For the Coal Lake station only six years of peak instantaneous flow are available and these values may not have been recorded during the actual passage of the seasonal freshet. Data for the Alaska Highway station is presented in Table 9.

Table 9: Annual Instantaneous Maximum Discharge Data for Wolf Creek

Year	Maximum Discharge (m^3/s)	Year	Maximum Discharge (m^3/s)
1993	19.00	2001	12.80
1994	2.78	2002	9.06
1995	14.80	2003	4.63
1996	4.45	2004	3.85
1997	25.10	2005	6.42
1998	4.17	2006	5.73
1999	4.39	2007	5.82
2000	6.28	2008	5.03

Derivation of the peak instantaneous flow for the 1:100 year event requires fitting the available dataset to a probability distribution. Typical distributions used in hydrology are shown in Table 9 with the peak instantaneous discharge for the 1:100 year event (Q100) derived for those distributions.

Table 10: Q100 (Peak Instantaneous Discharge) for Wolf Creek

Statistical Distribution	Q100 (m^3/s)
Normal	23.10
Three Parameter Log Normal	28.96
Two Parameter Log Normal	31.95
Gumbel Type II	32.75
Pearson Type III	32.84
Log Pearson Type III	55.70

Review of the results suggests that a value in the range of 30 m^3/s to 33 m^3/s appears reasonable. Moreover, both the normal distribution and the log Pearson Type III distributions have visually poor fits to the data. The 2007 Canadian Dam Safety guidelines further suggest that for datasets with less than 25 years of data a two parameter type distribution should be selected over three parameter distributions. Therefore, the Q100 determined for the two parameter log normal (31.95 m^3/s) is considered to be most appropriate for this case.

Using this determined Q100, estimates for the Q100 for various locations of the Fish Lake Hydro system can be made on the basis of relative watershed areas. The Q100 estimates are presented in Table 11.

Table 11: Q100 for Fish Lake System

Sub-watershed	Area (km^2)	Q100 (m^3/s)
Wolf Creek	177.0	31.95
Ditch #3	26.0	4.7
Louise Lake	19.7	3.6
Ditch #1 Spillway	23.0	4.2
Headpond #2	45.5	8.2

As can be seen from Table 11, the Wolf Creek relationship produces similar but slightly higher results to what was previously developed by NHC for Ditch #3 and the Ditch #1 spillway.

Also as can be seen from Table 11, Northland's area for the Ditch #1 Spillway is less than that used by NHC. Re-examination of the contributing area with available mapping suggests that NHC likely utilized the Plant #1 elevation as opposed to the higher Ditch #1 spillway elevation in its determination of area, thus over-estimating the contributing area.

11.3 IDF Passage through Ditch #3 and Louise Lake

Passage of the IDF through Ditch #3 and Louise Lake is dependent upon the interaction of peak outflow from Fish Lake, the peak local inflows to Ditch #3 (above the Ditch #3 Drop Box) and Louise Lake (below the Ditch #3 Drop Box), the capacities of the Louise Lake auxiliary spillway and of the Ditch #3 diversion to Franklin Lake, the concurrent discharge into Porter Creek from Louise Lake, and the proportioning of Ditch #3 flows into Louise Lake and the Ditch #3 Diversion to Franklin Lake.

To evaluate the passage of the IDF the following was assumed:

- Discharge into Porter Creek from Louise Lake would be set to a maximum of 0.3 m^3/s in order to protect the downstream infrastructure (Ditch #1, etc.) while still meeting minimum flow requirements for upper Porter Creek; and
- The discharge capacity of the Louise Lake auxiliary spillway is 7.9 m^3/s. It is also assumed that any minor freeboard deficiency at the auxiliary spillway can be corrected by placement of a minor volume of fill on either side of the spillway flume.

Based on these assumptions, the maximum discharge that can be released from Louise Lake during the IDF is 8.2 m^3/s.

From Table 11, the peak local inflow into Louise Lake is estimated to be 3.6 m^3/s; therefore, the maximum allowable flow into Louise Lake from Ditch #3 must be 4.6 m^3/s or less in order to pass the peak IDF flow through Louise Lake.

Sections 11.3.1 and 11.3.2 will examine whether or how inflows to Louise Lake from Ditch #3 can be limited to a maximum of 4.6 m^3/s, thereby confirming that the IDF can be passed by Louise Lake.

11.3.1 Ditch #3 Current Condition

In 2011, it was determined that the maximum discharge from Fish Lake during passage of the IDF with the current infrastructure and flood management protocols in place would be 4.3 m^3/s. From Table 11, the current estimate of peak local inflows entering into Fish Creek and Ditch #3 below Fish Lake is 4.7 m^3/s; thus the total entering into Ditch #3 under current conditions is 9.0 m^3/s.

Currently Ditch #3 will pass 4.1 m^3/s into Louise Lake with a canal elevation of 1030.35 m, which would permit a freeboard of at least 0.15 m. Therefore, the current flood management protocol for Ditch #3 includes creating a temporary lateral overflow spillway into the Ditch #3 Diversion to Franklin Lake with a capacity of at least 4.9 m^3/s at a canal elevation of 1030.35 m.

Based on the most recent survey data and developed capacity relationship for the Ditch #3 Drop Box, the lateral overflow spillway should have an invert of 1030.10 m and a length of at least 25 m to achieve this capacity. This represents a change from planning in the current OMS manual that was based on a less conservative overflow estimate. The new parameters for the temporary spillway should be updated in the OMS Manual.

With this proposed temporary overflow spillway, the IDF can be passed through both Ditch #3 and Louise Lake.

11.3.2 Ditch #3 Future Condition

Following upgrading of the Fish Lake dyke, the peak discharge from Fish Lake into Fish Creek during the IDF has been estimated to be 10.5 m^3/s. From Table 10, the current estimate of peak local inflows entering into Fish Creek and Ditch #3 below Fish Lake is 4.7 m^3/s; thus the total entering into Ditch #3 under proposed future conditions is 15.2 m^3/s.

To ensure that Louise Lake can pass the IDF event, the discharge from Ditch #3 into Louise Lake must be no more than 4.6 m^3/s; thus, at least 10.6 m^3/s must be accommodated by the Ditch #3 Diversion to Franklin Lake. Moreover, the control structure for the diversion inlet must be designed such that the 10.6 m^3/s of discharge into the diversion is achieved at a canal level that limits discharge through Ditch #3 into Louise Lake to a maximum of 4.6 m^3/s.

Based on these requirements NHC has developed a preliminary design for a lateral overflow weir at the entrance to a rehabilitated Ditch #3 diversion channel to Franklin Lake and has indicated that the discharge capacity can be achieved.

Therefore, passage of the IDF through Ditch #3 and Louise Lake can be achieved when the new infrastructure is installed.

It is understood that installation of the lateral spillway and rehabilitation of the diversion channel to the Franklin Lake will be initiated following regulatory approvals and will be in service in the same season that the Fish Lake Dyke upgrades are completed.

11.4 Ditch #1

The peak inflow for Ditch #1 was estimated by NHC to be 4.0 m^3/s and by Northland as 4.2 m^3/s. The current capacity of the Ditch #1 spillway is 4.7 m^3/s. Assuming that Louise Lake is limited to a maximum discharge of 0.3 m^3/s during passage of the IDF, the peak instantaneous flow at Ditch #1 would be 4.5 m^3/s or less. Therefore, the Ditch #1 spillway has sufficient capacity to pass the IDF event. Ditch #1 also has the Baily valve system to allow for discharge through the penstock if the Plant #1 turbine is not in operation. Thus, there is a further reserve capacity of up to 0.69 m^3/s available to supplement the spillway capacity.

11.5 Head Pond #2

Based on the use of Wolf Creek peak flow data, the Q100 peak inflow estimated for Headpond #2 is 8.2 m^3/s. Adding in Louise Lake discharge of 0.3 m^3/s leads to an expected total inflow at Dam #2 of 8.5 m^3/s.

The currently estimated capacity of the overflow spillway at Dam #2 with a Headpond elevation of 797.43 m and all stoplogs removed is 10.2 m^3/s; therefore, there is sufficient capacity at Dam #2 to pass the peak IDF while still allowing appropriate freeboard at the dam.

11.6 Summary

At this time it appears that the passage of the IDF through Ditch #3, Louise Lake, Ditch #1 and Headpond #2 is feasible under both current and proposed future operating conditions. Ditch #1 requires no changes to be suitable for current and future conditions.

Headpond #2 requires maintenance to its overflow spillway in order to ensure that all the necessary stoplogs can be removed and needs reaffirmation of the assumed spillway performance following the completion of the maintenance activities. In the interim contingency planning for use of an excavator to remove the spillway stoplogs below elevation 796.53 m should be developed and included in the OMS Manual.

For Ditch #3, passage of the IDF for current conditions would require establishing a temporary lateral overflow spillway into the Ditch #3 Diversion to Franklin Lake with a capacity of at least 4.9 m^3/s. The design parameters for temporary spillway include a length of 25 m and an invert of 1030.10 m. These parameters should be updated in the OMS manual.

Following upgrades of the Fish Lake dyke, a permanent lateral overflow spillway leading into a rehabilitated diversion channel to Franklin Lake will be required to assist in passing the peak IDF through Ditch #3 and Louise Lake. The lateral spillway will need a capacity of at least 10.6 m^3/s at a canal level of 1030.45 m. A preliminary design for this infrastructure has been prepared by NHC.

For Louise Lake the freeboard available at the embankment on either side of the auxiliary spillway needs to be assess further to confirm if minor low areas on the embankment beside the auxiliary spillway to Franklin Lake should be raised to ensure that adequate freeboard is in place.

Therefore the following recommendations are presented:

(1) Update the design parameters in the OMS manual for the temporary Ditch #3 spillway into the diversion channel to Franklin Lake to require a weir length of at least 25 m and an invert of 1030.10 m for passage of the peak IDF flow through Ditch #3

(2) In association with proposed upgrades to the Fish Lake Dyke proceed with installation of a lateral overflow spillway into the Ditch #3 Diversion to Franklin Lake. The lateral overflow spillway should have a discharge capacity of at least 10.6 m^3/s at a Ditch #3 canal level of 1030.45 m.

(3) Evaluate the freeboard requirements for the Louise Lake Auxiliary spillway embankment and if necessary raise any low areas to achieve the necessary freeboard.

12. Closure

Northland trusts that this report on the inspections of the water management structures and the review of relevant additional information associated with the Fish Lake Hydro system is sufficient for your purposes. Should you require additional information or clarification please contact the undersigned at your convenience.

Yours truly,

Northland Earth & Water Consulting Inc.

Original Signed and Sealed by

Cord Hamilton

Cord Hamilton, M.Eng., P.Eng., FEC
Civil Engineering Consultant
Ph: (867) 633-8937
Email: chamilton@Northlandengineering.ca

Photographs

Photograph #1: West end of Fish Lake dyke

Photograph #2: Discharge catwalk, Fish lake dyke

Photograph #3: East End of Fish Lake Dyke

Photograph #4: Ditch #3 Dyke at low freeboard section

Photograph #5: Ditch #3 following vegetation removal

Photograph #6: Ditch #3 Drop Box

Photograph #7: Condition of Joint Repair inside Ditch #3 Drop Box

Photograph #8: Louise Containment Dyke following vegetation removal

Photograph #9: Downstream Erosion from Beavers on Louise Lake Containment Dyke

Photograph #10: Small burrow or disturbance on Louise Lake Containment Dyke

Photograph #11: Louise Lake Auxiliary Spillway

Photograph #12: Louise Lake Auxiliary Spillway

Photograph #13: Louise Lake Control Structure

Photograph #14: Louise Lake Control Structure – downstream side

Photograph #15: Ditch #1 Spillway

Photograph #16: Ditch #1 Dyke

Photograph #17: Headpond #2 Spillway

Photograph #18: Dam #2 after raising elevation of crest road

Appendix A

Consolidated Dam Safety Recommendations

Table A1: Consolidated Dam Safety Recommendations

#	Structure	Recommendation
2008-04	Fish Lake Dyke	Previously planned construction to add riprap, to increase width and height of the dyke and to add an emergency spillway should be updated and completed.
2008-06	Fish Lake Dyke	Extend the staff gauge to the new dyke crest level, and check the staff gauge against a known stable bench mark for elevation.
2008-07	Fish Lake Dyke	Cut existing trees and shrubs that are growing on the existing dyke.
2008-10	Ditch #3	Cut all existing trees and shrubs on crest and upstream/downstream faces of the embankment.
2013-01	Ditch #3	Update the design parameters in the OMS manual for the temporary Ditch #3 spillway into the diversion channel to Franklin Lake to require a weir length of at least 25 m and an invert of 1030.10 m for passage of the peak IDF flow through Ditch #3 for the current operating conditions.
2013-02	Ditch #3	In association with proposed upgrades to the Fish Lake Dyke proceed with installation of a lateral overflow spillway into the Ditch #3 Diversion to Franklin Lake. The lateral overflow spillway should have a discharge capacity of at least 10.6 m^3/s at a Ditch #3 canal level of 1030.45 m.
2013-03	Ditch #3	Annually monitor the potential erosion at the left hand side of the chute wall of the Ditch #3 Drop Box at its exit into the flip bucket.
2013-04	Ditch #3	In spring 2013, investigate the extent of the animal burrows roughly 80 m upstream of the Drop Box, expose, and infill the burrows with low permeability soils
2010-04	Louise Lake Containment Dyke	Complete assessment and planning for any upgrades to this structure
2013-05	Louise Lake Containment Dyke	In summer 2013, expose and infill animal burrows located on the upstream face of the dyke.

Table A1: Consolidated Dam Safety Recommendations (continued)

#	Structure	Recommendation
2013-06	Louise Lake Containment Dyke	By spring 2013, establish and implement, at least temporarily, a public safety risk management plan for the dyke and maintain the program until upgrading of the dyke is completed or permanently if physical upgrading (lowering the slope or constructing a buttress) is not undertaken.
2013-07	Louise Lake Auxiliary Spillway	Confirm the capacity and stage discharge relationship of the auxiliary structure.
2013-08	Louise Lake Auxiliary Spillway	In summer 2013, evaluate potential piping that may be occurring underneath the timber floor of the spillway flume.
2013-09	Louise Lake Auxiliary Spillway	In summer 2013, obtain some specific measurements of the quality of the PWF timber within the flume. Some baseline measurements of the structure (width) should be made to monitor any future distortion that might develop due to degradation of the timber in the structure.
2013-10	Louise Lake Auxiliary Spillway	In summer 2013, remove accumulated sediment from within the spillway flume and continue to do so an annual basis.
2013-11	Louise Lake Auxiliary Spillway	Evaluate the freeboard requirements for the Louise Lake Auxiliary spillway embankment and if necessary raise any low areas to achieve the necessary freeboard.
2012-03	Louise Lake Control Structure	Removing remaining tree located on the structure.
2011-09	Ditch #1	An as-built survey drawing of the Ditch #1 channel and containment dyke should be produced and the minimum freeboard level identified for tying into remote monitoring activities.
2011-11	Ditch #1	An assessment of the stability of the penstock between the intake structure and Powerhouse #1 should be completed with the assumption that no ground anchors are present along the pipeline.
2011-13	Ditch #1 Spillway	Develop as-built drawings and operational protocols for use of the spillway.

Table A1: Consolidated Dam Safety Recommendations (continued)

#	Structure	Recommendation
2013-12	Ditch #1 Spillway	Annually prior to the on-set of the freshet remove accumulated debris from the inlet and exit of the spillway to ensure that the full capacity of the structure is available, if required, to discharge the freshet. This recommendation should be incorporated into the OMS manual.
2013-13	Ditch #1 Spillway	Install a remote monitoring station to monitor inflows into Ditch #1 upstream of the Ditch #1 spillway
2008-34	#2 Intake Structure	Repair Freeze thaw concrete damage in the intake building
2010-10	Pond #2 Dam	Complete an assessment of the low level outlet pipe to determine if it can be abandoned
2013-14	Pond #2 Spillway	Complete planned spillway maintenance in 2013 and reconfirm the spillway capacity following the maintenance activities
2013-15	Pond #2 Spillway	Until the spillway maintenance is completed, make contingency provisions for the use of excavation equipment to remove stoplogs below elevation 796.53 m should it be required for passage of flood flows and include the planning provisions in the OMS manual.

Table A2: Discharged or Superseded Dam Safety Recommendations

#	Structure	Recommendation
~~2012-01~~	~~General~~	~~Re-assess passage of the inflow design flood for current and proposed future operating conditions for infrastructure located downstream of Fish Lake.~~
~~2008-01~~	~~General~~	~~Submit an implementation report to address recommendations of the 2007 Dam Safety Report to the Yukon Water Board by September 1, 2010 (Clause 25, HY07-018).~~
~~2008-02~~	~~General~~	~~Develop and submit an Operations, Maintenance and Surveillance Manual for the Fish Lake hydro system to the Yukon Water Board by September 1, 2009 (Clause 24, HY07-018).~~
~~2008-03~~	~~General~~	~~Conducted an annual inspection of all water management structures associated with the Fish Lake hydro system and provide the report with the annual report to the Yukon Water Board (Clause 31, HY07-018).~~
~~2008-05~~	~~Fish Lake Dyke~~	~~Inspect the gated culvert control structure for remaining service life and carry out replacement or life extension (corrosion protection) as required.~~
~~2008-08~~	~~Fish Lake Dyke~~	~~Develop and implement a contingency plan to maintain adequate Freeboard until the dam height is increased~~
~~2011-01~~	~~Fish Lake Dyke~~	~~Modify flood management protocols to account for revised inflow design flood and capacity of Fish Lake discharge structure.~~
~~2011-02~~	~~Fish Lake Dyke~~	~~Add twice annual monitoring of Fish Lake dyke piezometer (BH01) to OMS manual and complete monitoring in spring and fall.~~
~~2008-09~~	~~Bonus Creek~~	~~Locate and document condition of this structure.~~
~~2010-01~~	~~Ditch #3~~	~~Establish Alarm levels for monitoring freeboard in Ditch #3 using the remote monitoring instrumentation~~
~~2008-11~~	~~Ditch #3~~	~~Evaluate the need to re-establish the Ditch #3 spillway structure~~
~~2008-12~~	~~Ditch #3~~	~~Survey embankment crest to identify freeboard levels and correct any areas with insufficient freeboard.~~

Table A2: Discharged or Superseded Dam Safety Recommendations (continued)

#	Structure	Recommendation
~~2011-04~~	~~Ditch #3~~	~~Repair or replace level monitoring instrumentation in 2011 to allow for remote monitoring of ditch water levels and application of determined alarm levels.~~
~~2011-03~~	~~Ditch #3~~	~~As the proposed upgrading of the Fish Lake dyke will lead to higher freshet discharges routinely being passed downstream into Ditch #3, the ability of Ditch #3 to pass these routine flows as well as the inflow design flood from Fish Lake should be evaluated.~~
~~2008-13~~	~~Ditch #3 Drop Structure~~	~~Monitoring of inflow to Ditch #3 in spring has to be carried out as often as required.~~
~~2010-03~~	~~Ditch #3 Drop Box~~	~~Complete an investigation of concrete erosion of the left chute wall and effect necessary repairs~~
~~2008-15~~	~~Louise Lake Containment Dyke~~	~~Install piezometers in the dyke, foundation and abutments to monitoring seepage conditions.~~
~~2008-16~~	~~Louise Lake Containment Dyke~~	~~Complete a topographic survey of the dyke and determine potential inundation limits that would result from failure of the dyke.~~
~~2008-17~~	~~Louise Lake Containment Dyke~~	~~Frequently inspect this dyke to note seepage conditions~~
~~2011-05~~	~~Louise Lake Containment Dyke~~	~~A magnitude of order cost estimate to upgrade the structure to the deterministic standard for seismic performance recommended by the 2007 Guidelines should be developed.~~
~~2011-06~~	~~Louise Lake Containment Dyke~~	~~A risk management approach should be considered in decision making on whether upgrades to the dyke are required and the risk analysis provided to regulators within an application for long term management of the Fish Lake hydro system.~~
~~2011-07~~	~~Louise Lake Containment Dyke~~	~~Existing vegetation growth on the structure should be removed.~~
~~2012-02~~	~~Louise Lake Containment Dyke~~	~~Monitor the minor depressions observed on the dyke in 2011 and determined if further investigation is warranted.~~

Table A2: Discharged or Superseded Dam Safety Recommendations (continued)

#	Structure	Recommendation
~~2008-14~~	~~Louise Lake Containment Dyke~~	~~Carry out a geotechnical investigation to confirm the dyke fill and foundation materials and then **analyze** seepage and **slope stability of the dyke.**~~
~~2008-18~~	~~Louise Lake Control Structure~~	~~Add Riprap to stop further bank toe erosion at south side of the downstream channel~~
~~2011-08~~	~~Louise Lake Control Structure~~	~~If technically feasible, the refurbished structure should include upstream stoplogs guides that would allow for stoplogs to be used for temporary flow control thereby allowing the replacement gate structure to be withdrawn for inspection and maintenance purposes~~
~~2008-19~~	~~Louise Lake Control Structure~~	~~Remove vegetation that is growing on the top of the cross beams~~
~~2008-20~~	~~Louise Lake Control Structure~~	~~Repair freeze thaw spalling of downstream wing walls~~
~~2012-04~~	~~Louise Lake Control Structure~~	~~Complete as-built plans of the refurbished structure.~~
~~2008-21~~	~~Ditch #1~~	~~Remove shallow rooting trees from downstream dyke crest and side slopes.~~
~~2008-22~~	~~Ditch #1~~	~~Survey embankment crest elevation along Ditch #1 to identify low sections that require addition freeboard.~~
~~2011-10~~	~~Ditch #1~~	~~Establish remote monitoring of the water level in Ditch #1.~~
~~2011-14~~	~~Ditch #1 Spillway~~	~~Add observation of seepage in the former channel of Porter Creek between the inlet of Ditch #1 and the exit of the Ditch #1 Spillway to routine surveillance activities for Ditch #1 in the OMS Manual for Fish Lake hydro.~~
~~2008-23~~	~~Ditch #1 Auxiliary Spillway~~	~~Investigate seepage at downstream toe of spillway exit.~~

Table A2: Discharged or Superseded Dam Safety Recommendations (continued)

#	Structure	Recommendation
~~2008-24~~	~~Ditch #1 Auxiliary Spillway~~	~~Access condition of timber mat that provides erosion protection for the spillway discharge.~~
~~2011-12~~	~~Ditch #1 Spillway~~	~~Complete remaining construction activities for the new spillway in summer 2011.~~
~~2012-05~~	~~Ditch #1 Spillway~~	~~Install a staff gauge at the structure to allow for recording of geodetic elevations at the inlet to the spillway.~~
~~2008-25~~	~~Pond #1 Intake~~	~~Confirm that stoplogs are functional and can be fully closed~~
~~2008-26~~	~~Penstock #1~~	~~Complete corrosion and pipe thickness assessment of the penstock.~~
~~2008-27~~	~~Penstock #1~~	~~Expose and inspect Penstock ground anchors~~
~~2008-29~~	~~Head Pond #2 Dam~~	~~Remove all trees and shrubs on both faces of the dam, around the spillway and for 6 m beyond the dam toe~~
~~2009-30~~	~~Head Pond #2 Dam~~	~~Clean low level outlet stilling basin and ensure that the basin has a functioning drain~~
~~2008-31~~	~~Head Pond #2 Dam~~	~~Install a weir downstream from the stilling basin to monitor seepage~~
~~2011-15~~	~~Pond #2~~	~~Remove debris from overflow spillway channel and build up low freeboard section of spillway channel~~
~~2008-28~~	~~Head Pond #2 Dam~~	~~Repair freeze thaw damage to concrete components of spillway.~~
~~2008-32~~	~~#2 Intake Structure~~	~~Prepare a written procedure for dewatering and re-watering penstock #2~~

Table A2: Discharged or Superseded Dam Safety Recommendations (continued)

#	Structure	Recommendation
~~2008-33~~	~~#2 Intake Structure~~	~~Replace stoplogs and clean stop log guides~~
~~2008-35~~	~~#2 Intake Structure~~	~~Rehabilitate or replace the penstock inlet valve to ensure that it can complete close to dewater the penstock~~
~~2008-36~~	~~#2 Penstock~~	~~Periodically inspect the wood stave pipe and seal the leakages by appropriate method.~~
~~2008-37~~	~~#2 Penstock~~	~~Reinforce any wood decay with appropriate means or consider wood stave replacement.~~
~~2008-38~~	~~#2 Penstock~~	~~Ponding of water next to penstock should be drained away by ditching.~~
~~2008-39~~	~~#2 Penstock~~	~~Cut all shrubs along the route (0.9 m on both sides) and remove any vegetation growth on the pipe.~~
~~2008-40~~	~~#2 Penstock~~	~~Expose and inspect penstock ground anchors~~
~~2009-01~~	~~Ditch #1~~	~~Maintain a minimum freeboard of 0.3 m at lowest point along the Ditch #1 channel and Pond #1~~
~~2010-02~~	~~Ditch #3~~	~~Plan on routine vegetation removal for the containment dyke upstream face, crest and downstream slope~~
~~2010-05~~	~~Louise Lake Control Structure~~	~~Complete an assessment (if technically feasible) of the condition of the sluice gate timbers in 2010~~
~~2010-06~~	~~Louise Lake Control Structure~~	~~Plan on refurbishment of this structure within five years or less.~~

Table A2: Discharged or Superseded Dam Safety Recommendations (continued)

#	Structure	Recommendation
~~2010-07~~	~~Ditch #1 Spillway~~	~~Complete a review of the serviceability of this spillway to manage excess flow in Ditch #1~~
~~2010-08~~	~~Ditch #1 Spillway~~	~~Complete additional repairs to the existing spillway and/or replace the spillway in 2010~~
~~2010-09~~	~~Ditch #1~~	~~Raise the low freeboard section of the dyke crest in 2010~~

YUKON WATER BOARD

Pursuant to the *Waters Act* and Regulation, the Yukon Water Board hereby grants a Type A Water Use Licence for a power undertaking to:

Yukon Electrical Company Ltd.
100-1100 First Avenue
Whitehorse Yukon Y1A 3T4

LICENCE NUMBER: HY12-065

RENEWAL: This licence is deemed to be a renewal of HY10-083.

LICENCE TYPE: A **UNDERTAKING:** Power, Class 1

WATER MANAGEMENT AREA: 02

LOCATION: Fish Lake, Louise Lake, Franklin Lake, Jackson Creek, Porter Creek, West McIntyre Creek and interconnected drainages.

PURPOSE: Operation of the Fish Lake Generating Station and the Fish Lake Dam.

EFFECTIVE DATE: May 31, 2013 **EXPIRY DATE:** May 30, 2038

This licence shall be subject to the restrictions and conditions contained herein and to the restrictions and conditions contained in the *Waters Act* and the *Waters Regulation* made thereunder.

Approved this 28 day of May, 2013

Witness

Minister, Executive Council Office
Government of Yukon

Issued this 29th day of May, 2013

Witness

Chairperson
Yukon Water Board

PART A - DEFINITIONS

"Act" means the *Waters Act* and any amendments thereto.

"Application" and "Water Use Application" means Water Use Application HY12-065, including any additional submissions and/or revisions, submitted to the Board by the Licensee.

"Board" means the Yukon Water Board.

"Construction Phase" means the period of time from the issuance of this licence until December 31, 2015, during which all reconstructions have been completed.

"CPUE" means catch per unit effort, a common method for assessing fisheries populations.

"Dam Safety Guidelines" means the most current version of the Dam Safety Guidelines issued by the Canadian Dam Association.

"Decommissioning Plan" means the *Fish Lake Hydro Decommissioning Plan*, dated September 2, 2010, or the most current version.

"Franklin Lake Adaptive Management Study Period" means a five year period of time commencing at the end of the Construction Phase during which shoreline erosion mitigation and water quality optimization studies are conducted on Franklin Lake.

"General Operation Phase" means the period of time from the end of the major reconstruction phase until the expiry date of this licence.

"Inspector" means any person designated as an Inspector under the Act.

"Natural Boundary" means the visible high water mark of any lake, river, stream or other body of water where the presence and action of water is so common and usual and so long continued as to mark upon the soil of the bed of the lake, river, stream or other body of water a character distinct from that of the banks thereof, both in respect to vegetation and in respect to the nature of the soil itself. In addition, the best estimates of the edge of dormant or old side channels and marsh areas are considered to be Natural Boundaries.

"OMS" means the Operations, Maintenance and Surveillance Manual.

"Ramping" means the act of changing discharge from a control structure.

"Regulation" means the *Waters Regulation* made under the Act.

"Spill Contingency Plan" means the *Environmental Response Plan* (2012) included in exhibit 1.4.1 of the Application, or the most current version.

"Watercourse" means any stream, lake, pond, river, creek, spring, ravine or swamp whether ordinarily containing water or not.

"Wetted Perimeter" means the horizontal extent of the present water level while the work is taking place.

PART B – GENERAL CONDITIONS

Other Laws

1. No condition of the water use licence limits the applicability of any statutory authority.

2. All water uses and activities authorized by this licence shall occur on property that the Licensee has the right to enter upon and use for that purpose.

Correspondence

3. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

   a) To the Licensee, if left at, faxed to, or mailed by registered mail to the following address:

   Yukon Electrical Company Ltd.
   100-1100 First Avenue
   Whitehorse YT Y1A 3T4
   Telephone: (867) 633-7000
   Fax: (867) 633-5797

   and shall be deemed to have been given to the Licensee on the day it was left or faxed, or 7 days after the day it was mailed, as the case may be.

   b) To the Board, if left at, faxed to, or sent by registered mail to the following address:

   Yukon Water Board
   Suite 106-419 Range Road
   Whitehorse YT Y1A 3V1
   Telephone: (867) 456-3980
   Fax: (867) 456-3890

and shall be deemed to have been given to the Board on the day it was left or faxed, or 7 days after the day it was mailed, as the case may be.

c) The Board or the Licensee may, by notice in writing, change its address for delivery.

Non-Compliance

4. In the event that the Licensee fails to comply with any provision or condition of this licence, the Board may, with the approval of the Minister and subject to the Act, cancel the licence.

Spills and Unauthorized Discharges

5. Where a spill or an unauthorized discharge occurs, that is of a reportable quantity under the Yukon *Spills Regulations,* the Licensee shall immediately contact the 24-hour Yukon Spill Report number, (867) 667-7244 and implement the Spill Contingency Plan. A detailed written report on any such event including, but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than 10 days after the occurrence.

6. The Licensee shall apply the relevant procedures in the Spill Contingency Plan. The Licensee shall review the Spill Contingency Plan annually and shall provide a summary of that review, including any revisions to the plan, as a component of the annual report.

7. The Licensee shall maintain a log book of all spill or unauthorized discharge occurrences, including spills that are less than the reportable quantities under the Yukon *Spills Regulations.* The log book shall be made available at the request of an Inspector. The log book shall include, but not necessarily be limited to the:

a) date and time of the spill;
b) substance spilt or discharged;
c) approximate amount spilt or discharged;
d) distance between the spill or discharge and the nearest Watercourse; and
e) remedial measures taken to contain and clean-up the spill area or to cease the unauthorized discharge.

8. The Licensee shall include a summary of all spills or unauthorized discharges that occurred during the year reported, as part of the annual report.

9. All personnel shall be trained in procedures to be followed and the equipment to be used in the containment of a spill.

10. The Spill Contingency Plan shall be posted at all generating stations and job sites.

Environmental Management and Safety Plan

11. Prior to commencement of use of heavy equipment adjacent to or in close proximity to the Wetted Perimeter or Natural Boundary of any Watercourse, the Licensee shall submit to the Board an *Environmental Management and Safety Plan* as described in Exhibit 1.4.2 of the Application, including, but not limited to:

    a) notification of the site supervisor and contact phone number;
    b) the location of the work site;
    c) the schedule for undertaking the work activities; and
    d) details of the proposed activities to be undertaken.

Hazardous Materials Storage

12. A complete inventory of chemicals, fuels, oils and other hazardous materials and their locations shall be maintained by the Licensee. An up to date Spill Contingency Plan suitable for such materials shall be maintained. Any revisions to the Spill Contingency Plan shall be submitted to the Board within 60 days of the revision.

Annual Reports

13. Annual reports shall be submitted to the Board by the Licensee. The initial report shall cover the period from the effective date of this licence to December 31, 2013 and shall be submitted to the Board on or before February 28, 2014. Subsequent reports shall cover the period from January 1st to December 31st of each year and shall be submitted to the Board on or before February 28th immediately following the end of the reporting period.

14. Annual reports shall include the information required by this licence and by the Regulation, including, but not necessarily limited to:

    a) maximum, minimum and mean daily water levels reported by month on:

        i) Fish Lake;
        ii) Franklin Lake;
        iii) Louise Lake;
        iv) Headpond #1; and
        v) Headpond #2.

    b) maximum, minimum and mean daily water flows reported by month at:

        i) Fish Creek below the Fish Lake Dam;
        ii) Ditch #3;

iii) Ditch #3 diversion;
iv) Jackson Creek below Franklin Lake;
v) Ditch #2;
vi) Penstock #1;
vii) Penstock #2;
viii) McIntyre Creek below Plant #2; and
ix) McIntyre Creek at Range Road.

c) maximum, minimum and mean daily power production from all operational turbines, reported by month;
d) progress toward completion, status and inspection records of scheduled construction for major system improvements, including the:

i) Fish Lake Control Structure;
ii) Ditch #3 Channel;
iii) Ditch #3 Diversion;
iv) Ditch #3 Drop box; and
v) other planned upgrades;

e) information regarding the purpose, nature and extent of any significant maintenance work carried out;
f) comprehensive descriptions of changes to, compliance with and deviation from the control guidance detailed within the Fish Lake Hydro OMS along with detailed descriptions of any corrective actions;
g) details of any updates to the Spill Contingency Plan;
h) details of any work undertaken under an Environmental Management and Safety Plan, and
i) any other information or reports required by this licence or the Regulation.

Quarterly Reports

15. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31st, June 30th, September 30th and December 31st of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

16. Quarterly reports shall include the information required by this licence and by the Regulation, including, but not necessarily limited to:

a) mean daily water levels on Fish Lake, Franklin Lake, Louise Lake, Head Pond #1 and Head Pond #2;
b) mean daily flow through the gates of the Fish Lake Control Structure;
c) mean daily flows through the Fish Lake Generating Station turbines;
d) mean daily flows through Ditch #1 and the overflow spillway;
e) mean daily flows through Pond #1 and Pond #2;
f) flows and water levels for spills from Pond #2;
g) flows from Louise Lake Control Structure, Louise Lake Auxiliary Spillway, Plant #1 and Plant #2;

h) flows through Ditch #3 and the Ditch #3 diversion;
i) mean daily power production from all operational turbines; and
j) any other information or reports required by this licence or by the Regulation.

Reports

17. The Licensee shall provide to the Board one unbound, single-sided, paper copy of all reports required by this licence. All reports must be reproducible by standard photocopier.

18. The Licensee shall upload electronic copies of all reports required by this licence to the Board's online licensing registry, the WATERLINE. Electronic copies shall be submitted in one of the following formats: Word 97 - 2003, Excel 97 - 2003 workbooks, or Adobe .pdf format. Water quality results uploaded to the WATERLINE must be presented in Excel 97-2003.xls format.

PART C - OPERATING CONDITIONS

Description of Water Use - Construction Phase

19. All works associated with this licence shall be constructed and maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

20. The Licensee is authorized from the effective date of this licence through to December 31, 2015, to conduct improvements and upgrades to the Fish Lake Hydro System. Construction of the improvements and upgrades to the Fish Lake Hydro system, include:

    a) the Fish Lake Control Structure;
    b) Ditch #3;
    c) Ditch #3 Diversion; and
    d) the Ditch #3 Dropbox,

    as described in Exhibit 1.2, Section 2.8, 'Project Infrastructure and Planned Upgrades', and subject to the conditions of this licence. Where there is discrepancy between the Application and this licence, the conditions of this licence shall prevail.

21. At least 10 days prior to the commencement of construction, the Licensee shall submit to the Board final detailed design construction drawings for the structures authorized within clause 20 of this licence. The final detailed design drawings must be consistent with the drawings which were submitted as part of the Application in Water Use Register HY12-065 and shall be sealed by a Professional Engineer

licensed to practice in Yukon. All construction shall be carried out in accordance with the final design drawings.

22. Where site conditions require modifications to the final detailed design submitted to the Board, the Licensee shall submit to the Board a minimum of 10 days prior to the commencement of the construction schedule:

    a) written details of the modifications proposed to be made to the specifications and quality assurance/quality control procedures previously submitted to the Board as part of the Application;
    b) a written detailed construction schedule and the name and contact number(s) of the construction superintendent; and
    c) an explanation, signed by a Professional Engineer licensed to practice in Yukon, for the change, including an assessment of the potential impact on the performance of the works.

23. Within 60 days of completion of construction of the structures authorized within clause 20 of this licence, the Licensee shall submit to the Board, as-built design drawings, sealed by a Professional Engineer licensed to practice in the Yukon.

24. During the Construction Phase, the Licensee shall comply with the following:

    a) the water surface elevation on Fish Lake shall be maintained between a controlled minimum of 1110.72 metres and a controlled maximum of 1112.29 metres as measured from geodetic datum;

    b) the water surface elevation on Louise Lake shall be maintained between a controlled minimum of 1013.73 metres and a controlled maximum of 1014.61 metres as measured from geodetic datum;

    c) the water surface elevation in Head Pond #2 shall be maintained between elevation 796.00 metres and 797.00 metres as measured from geodetic datum;

    d) a minimum instantaneous flow of 0.28 m^3/s to maximum instantaneous flow of 2.00 m^3/s shall be discharged through the Fish Lake control structure;

    e) a minimum instantaneous flow of 0.14 m^3/s to maximum instantaneous flow of 2.00 m^3/s shall be discharged through the Louise Lake control structure; and

    f) a minimum instantaneous flow of 0.60 m^3/s to maximum instantaneous flow of 2.00 m^3/s shall be discharged out of Head Pond #2 from December to April.

25. The Licensee shall complete the authorized activities during the Construction Phase prior to commencing activities authorized for the General Operations Phase.

26. The Licensee shall notify the Board, in writing, when Construction Phase has been completed.

Description of Water Use – General Operation Phase

27. All works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

28. The Licensee is hereby authorized to:

a) commence the General Operations Phase on January 1, 2016;
b) obtain and discharge up to 2.00 m^3/s of water from Fish Lake, Louise Lake, Porter Creek, and West McIntyre Creek;
c) store water in Fish Lake, Louise Lake, Head Pond #1 and Head Pond #2;
d) divert the flow of Fish Creek into Louise Lake Ditch #3;
e) divert flows to Franklin Lake via the Ditch #3 diversion subsequent to its construction/upgrade;
f) divert the flow from Louise Lake into Porter Creek via Ditch #2;
g) divert the flow of Porter Creek into Head Pond #1;
h) use stored and/or diverted water for the purpose of power generation at Hydro Plant #1 and Hydro Plant #2;
i) discharge water into McIntyre Creek from Hydro Plant #2 at a maximum rate not to exceed 2.00 m^3/s;
j) divert the flow between Louise Lake and Franklin Lake via the auxiliary spillway; and
k) discharge water to Franklin Lake, Porter Creek and West McIntyre Creek.

as described in the Application and subject to the conditions of this licence. Where there is discrepancy between the Application and this licence, the conditions of this licence shall prevail.

Water Surface Elevations – General Operation Phase

29. The water surface elevation on Fish Lake shall be maintained between a controlled minimum of 1111.04 metres and a controlled maximum of 1112.79 metres as measured from geodetic datum.

30. The water surface elevation on Louise Lake shall be maintained between a controlled minimum of 1013.73 metres and a controlled maximum of 1014.61 metres as measured from geodetic datum.

31. The water surface elevation on Franklin Lake during the Franklin Lake Adaptive Management Study Period shall be maintained below a maximum of 1004.20

metres and between 1001.50 to 1003.50 metres, as measured from geodetic datum, from June through August.

32. The water surface elevation in Head Pond #2 shall be maintained between elevation 796.00 metres and 797.18 metres as measured from geodetic datum.

Minimum Instantaneous Flows

33. A minimum instantaneous flow of 0.15 m^3/s shall be discharged through the Fish Lake control structure.

34. A minimum instantaneous flow of 0.10 m^3/s shall be discharged through the Louise Lake control structure.

35. A minimum instantaneous flow of 0.60 m^3/s shall be discharged out of Head Pond #2 from December to April.

Operations, Maintenance and Surveillance Manual

36. On or before May 30, 2014, the Licensee shall submit to the Board an updated OMS including at a minimum, but not necessarily limited to, the following specific and updated provisions:

    a) updated maximum historical drawdowns for Fish Lake and Louise Lake to be used as maximum winter drawdowns;

    b) protocols for the management of system-wide hydrology in the event of prolonged drought or flood for best protection of fish and fish habitats, including salmon use in McIntyre Creek, including establishment of specific communication and coordination protocols during these events;

    c) protocols for response and mitigation procedures in the event of fisheries population declines and age class anomalies occur in Fish Lake and Louise Lake;

    d) details of the specific operational protocols and water management strategies utilized to maintain the operation of the systems in a manner that avoids exceeding the full supply level at Fish Lake and maintains Whitefish habitat;

    e) protocols and provisions for limiting the proliferation of Rainbow Trout within and outside of the Fish Lake catchment;

    f) protocols for protecting, minimizing and mitigating any damage to shorebird habitat during Construction and General Operation Phases;

g) enhanced protocols for maintenance of Louise Lake water surface elevations levels at the minimum possible range and amplitude, balancing the needs to reduce erosion, protect fisheries and fish habitat and convey water for hydro operations;

h) protocols for identification, protection and mitigation of heritage resources within the catchment during Construction and General Operations Phases;

i) updated reporting protocols; and

j) consolidated adaptive management plans for system operations and response during both the Construction Phase and General Operations Phase.

37. On or before, December 31, 2020, the Licensee shall submit to the Board an updated OMS including at a minimum, but not necessarily limited to, the following specific and updated provisions:

a) protocols and operational levels relating to fisheries habitat protection in Louise Lake as determined from the Louise Lake Fisheries Migration and Louise Lake Littoral Connectivity Threshold Studies and including specification that the maximum winter drawdown during the ice cover season at Louise Lake not exceed 0.50 metres; and

b) updated provisions for minimizing and mitigating fish stranding at all hydrologic control and discharge locations, as required by condition 34 of this licence, and minimization and mitigation of fish entrainment through the turbines.

Franklin Lake Shoreline Erosion Study

38. The Licensee shall submit to the Board, a Franklin Lake Shoreline Erosion Study no later than December 31, 2020. The Franklin Lake Shoreline Erosion Study shall be conducted in order to identify the potential for shoreline erosion of the lake and develop an appropriate mitigation strategy.

Louise Lake Fisheries Migration Protocol and Littoral Connectivity Threshold

39. On or before August 29, 2013, the Licensee shall submit to the Board a Louise Lake Fisheries Migration Protocol that includes at a minimum, but is not limited to, specifying the frequency, time periods and water surface elevation of a two-week period necessary to allow fish migration to Louise Lake from associated wetlands.

40. The Licensee shall monitor the results of the Louise Lake Migration Protocol to determine the effectiveness of a two-week migration period and adjust, if necessary, the length of that period. The Licensee shall make appropriate adjustments to this

protocol, update those changes within the OMS and detail any updates as required in the annual report.

41. The Licensee shall establish the spring/summer littoral connectivity threshold, update the OMS to include this operational level and report the change as required in the annual report.

PART D - MONITORING

42. Annually, the Licensee shall carry out an inspection of all water management structures authorized by this licence. The inspection shall be carried out by a qualified Professional Engineer licensed to practice in Yukon, and shall follow, at a minimum but not limited to, the recommendations contained in the Dam Safety Guidelines. The findings and recommendations from the inspection shall be submitted as part of the annual report and shall include but not be limited to:

    a) documentation of the inspection locations and methodologies;
    b) the results of the inspection;
    c) all problems identified;
    d) remedial measures recommended; and
    e) the status of any remedial measures recommended in the previous year's report with an explanation regarding any recommendation not implemented.

43. The Licensee shall collect, assure and report all routine hydrologic data from the system-wide telemetry locations necessary to comply with operations and reporting licence conditions.

44. On or before May 30, 2014, the Licensee shall install at Louise Lake a calibrated, within-lake, manual water surface gauge site readily available for visual inspection and indicate the location of the gauge as part of the annual report. The Licensee shall cross-calibrate the gauge against the existing telemetry installation and note any offsets or biases within the OMS.

45. On or before May 30, 2014, the Licensee shall submit to the Board a plan for a fisheries monitoring program. The purpose of the monitoring plan is to confirm assessments of the effects of long-term hydro system operations on fish populations. Upon submission, the Licensee shall implement the plan submitted to the Board. The monitoring plan shall include, but not necessarily be limited to, the following:

    a) at Fish Lake, monitor Round Whitefish recruitment and year-class strength every 10 years;
    b) at Fish Lake, Louise Lake, and Franklin Lake, undertake CPUE monitoring every 5 years of all adult fish populations, including Arctic Grayling and Lake Trout;
    c) at Louise and Franklin Lakes, monitor water quality, including oxygen and water temperature during the period that the lakes are stratified. This

monitoring is to be conducted annually until profiles representative of the operating regime have been established for these lakes;

d) at Louise and Franklin Lakes, develop and implement a fisheries abundance and age structure monitoring program;

e) monitor the water balance of Franklin Lake including inflows, outflows and water levels during the Franklin Lake Adaptive Management Study Period;

f) monitor the potential for fish stranding in ditch #3 diversion to Franklin Lake once the diversion is operational; and

g) review the reported downstream flow information, including flows in diversion channels, for the purpose of maintaining the ongoing, long-term habitat productivity and health of fish populations throughout the hydro system.

46. The Licensee shall monitor fish stranding during diversion events in all spillway channels and monitor the effectiveness of Ramping, fish salvages and other means of reducing fish stranding. The findings of this monitoring shall be submitted as part of the annual report.

47. Where fish stranding occurs as a result of the use of diversion channels, the Licensee shall conduct fish salvage, subject to any permit or authorization by Fisheries and Oceans Canada.

48. On or before May 30, 2014, the Licensee shall submit to the Board a plan for monitoring nesting shorebirds to confirm assessments regarding the effects of long-term operations on nesting success of shoreline nesting birds at Fish Lake. The monitoring plan shall be implemented in the first year of operations following the reconstruction of the Fish Lake dyke and shall be carried out for a 3 year term. The monitoring plan shall include at a minimum, but not limited to: a schedule for monitoring, duration of monitoring, methods to be used, species and location(s) of monitoring.

APPENDIX 1

Table of Deliverables

Clause	Deliverable	Frequency	Due
5	Spill report	As required	No later than 10 days after occurrence
6, 8, 12	Updated Spill Plan, summary of all spills as part of annual report	• Annually • As required	• Feb 28/14 • Feb 28th of the year following the reporting period • Within 60 days of revision if hazardous materials are updated within the plan
11	Environmental Management and Safety Plan	As required	Prior to commencement of use of heavy equipment
13, 14, 17, 18	Annual reports	• Effective date to Dec. 31/13 • Annually: Jan. 1 to Dec. 31	• Feb. 28/14 • Feb. 28 of the year following the reporting period
15, 16, 17, 18	Quarterly Reports	• Period ending March 31 • Period ending June 30 • Period ending Sept. 30 • Period ending Dec. 31	• Within 30 days of the end of each reporting period
20, 21, 22	Final design drawings and minor modifications to final design drawings	As required	At least 10 days prior to commencement of construction
23	As-built design	As required	Within 60 days of

Clause	Deliverable	Frequency	Due
	drawings		completion of construction
26	Notification when Construction Phase has been completed	As required	By December 31, 2015 at the latest
36, 14	Operations, Maintenance & Surveillance Manual	• Once for Initial Submission • Annually, if updated as part of annual report	• On or Before May 30, 2014 • Feb. 28/14 • Feb. 28 of the year following the reporting period
37, 14	Updated Operations, Maintenance & Surveillance Manual	• Once for Initial Submission • Annually, if updated as part of annual report	• On or Before Dec. 31, 2020 • Feb. 28/14 • Feb. 28 of the year following the reporting period
38	Franklin Lake Shoreline Erosion Study	• Once	• No later than Dec. 31, 2020
39, 40, 41, 14	Louise Lake Fisheries Migration Protocol	• Once • Annually, if updated as part of annual report	• On or Before Aug. 29, 2013 • Feb. 28/14 • Feb. 28 of the year following the reporting period
42, 14	Water Management Structure Inspection Report	• As required, as part of annual report	• Feb. 28/14 • Feb. 28 of the year following the reporting period
44, 14	Report on Louise Lake Water Surface Gauge Installation & Maintenance	• As required, as part of annual report	• Feb. 28/14 • Feb. 28 of the year following the reporting period
45	Plan for a Fisheries Monitoring Program	• Once	• On or Before May 30, 2014
46	Reporting Fish Stranding Events	• As required, as part of annual report	• Feb. 28/14 • Feb. 28 of the year following the reporting period

Clause	Deliverable	Frequency	Due
48	Plan for Monitoring Nesting Shorebirds	• Once	• On or Before May 30, 2014

APPENDIX 2

Summary of Principal[1] Hydrologic Licence Conditions

Clause	Term	HY12-065 Construction Phase	HY12-065 General Operation Phase
Cover page, 20	Length of Licence 25 years	May 31, 2013 to December 31, 2015	January 1, 2016 to May 30, 2038
24, 29	Fish Lake Level	max: 1112.29m min: 1110.72m	max: 1112.79m min: 1111.04m
24, 30	Louise Lake Level	max: 1014.61m min: 1013.73m	max: 1014.61m min: 1013.73m
31	Franklin Lake Level	N/A	max: 1004.20m min: 1001.50 – 1003.50m (Annually June through August) max. and min. water elevations subject to change pending results of Franklin Lake Adaptive Management Study
24, 32	Head Pond #2	max: 797.00m min: 796.00m	max: 797.18m min: 796.00m
	Minimum Instantaneous Flow		
24, 33	Fish Lake Control Structure	$0.28m^3/s$	$0.15m^3/s$
24, 34	Louise Lake Control Structure	$0.14m^3/s$	$0.10m^3/s$
24, 35	Head Pond #2	$0.60m^3/s$	$0.60m^3/s$
	Maximum Instantaneous Flow		
24, 28	Fish Lake Control Structure	$2.00m^3/s$	$2.00m^3/s$

Clause	Term	HY12-065 Construction Phase	HY12-065 General Operation Phase
24, 28	Louise Lake Control Structure	$2.00m^3/s$	$2.00m^3/s$
24, 28	Head Pond #2	$2.00m^3/s$	$2.00m^3/s$

[1]*Other site and time specific hydrologic licence conditions may also apply – refer to licence conditions for additional detail.*

CW-YECL-18

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 11

In Business Case 11, YECL indicates it will be replacing an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

Request:

(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes in efficiency have been incorporated into forecasts of diesel fuel.

Response:

(a) Yukon Electrical is unable to provide an analysis that compares the efficiency of the old and new units for the following reasons:

- The vendor of the proposed new unit was contacted several times for information regarding the efficiency of the unit, but was unable to provide any information to Yukon Electrical.
- Yukon Electrical measures efficiency at the plant level and does not track the efficiency of each individual unit. As a result, there is no data on the current unit with which to compare the new unit's efficiency (if it were available).

Yukon Electrical notes that new diesel engines have to meet improved emission standards. This often means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power performance.

The primary driver for this project is the need for a new unit due to the end of life condition of the existing unit, not increased efficiency. As a result,

Yukon Electrical has not incorporated efficiency into its business case for the need for this project.

As the change in efficiency resulting from the new unit is not currently known, no changes in efficiency have been incorporated into the diesel fuel forecast for the test years 2013-2015. Any increases or decreases in efficiency will be factored into a future application, once the unit is operational and the impact on overall efficiency for the Beaver Creek plant is known.

CW-YECL-19

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 12

In Business Case 12, YECL indicates it will require a new standby generator. In the business case, YECL provides four alternatives. The City requires information to assess the chosen alternative.

Request:

(a) Please provide a financial analysis that compares the four alternatives, and demonstrates that the chosen option is the least cost option.

Response:

(a) A financial analysis comparing the four alternatives was not carried out as the driver for the project is to provide a standby power supply for customers should there be a loss of generation on the Yukon Interconnected System or a loss of Distribution System capability on the single radial line to the service area. Please refer to YUB-YECL-46 for further information on the need for the project.

CW-YECL-20

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 13

In Business Case 13, YECL indicates it will be replacing an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

Request:

(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes in efficiency have been incorporated into forecasts of diesel fuel.

Response:

(a) Yukon Electrical is unable to provide an analysis that compares the efficiency of the old and new units for the following reasons:

- The vendor of the proposed new unit was contacted several times for information regarding the efficiency of the unit, but was unable to provide any information to Yukon Electrical.
- Yukon Electrical measures efficiency at the plant level and does not track the efficiency of each individual unit. As a result, there is no data on the current unit with which to compare the new unit's efficiency (if it were available).

Yukon Electrical notes that new diesel engines have to meet improved emission standards. This often means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power performance.

The primary driver for this project is the need for a new unit due to the end of life condition of the existing unit, not increased efficiency. As a result,

Yukon Electrical has not incorporated efficiency into its business case for the need for this project.

As the change in efficiency resulting from the new unit is not currently known, no changes in efficiency have been incorporated into the diesel fuel forecast for the test years 2013-2015. Any increases or decreases in efficiency will be factored into a future application, once the unit is operational and the impact on overall efficiency for the Watson Lake plant is known.

CW-YECL-21

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 14

In Business Case 14, YECL indicates it will be replacing an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

Request:

(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes in efficiency have been incorporated into forecasts of diesel fuel.

Response:

(a) Yukon Electrical is unable to provide an analysis that compares the efficiency of the old and new units for the following reasons:

- The vendor of the proposed new unit was contacted several times for information regarding the efficiency of the unit, but was unable to provide any information to Yukon Electrical.
- Yukon Electrical measures efficiency at the plant level and does not track the efficiency of each individual unit. As a result, there is no data on the current unit with which to compare the new unit's efficiency (if it were available).

Yukon Electrical notes that new diesel engines have to meet improved emission standards. This often means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power performance.

The primary driver for this project is the need for a new unit due to the end of life condition of the existing unit, not increased efficiency. As a result,

Yukon Electrical has not incorporated efficiency into its business case for the need for this project.

As the change in efficiency resulting from the new unit is not currently known, no changes in efficiency have been incorporated into the diesel fuel forecast for the test years 2013-2015. Any increases or decreases in efficiency will be factored into a future application, once the unit is operational and the impact on overall efficiency for the Destruction Bay plant is known.

CW-YECL-22

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 15

In Business Case 15, YECL indicates it will be replacing an old diesel generator with a new diesel generator. The City requires information to assess the impact of the new unit.

Request:

(a) Please provide an analysis that compares the efficiency of old and new units. In the response, please provide an analysis that clearly demonstrates how changes in efficiency have been incorporated into forecasts of diesel fuel.

Response:

(a) Yukon Electrical is unable to provide an analysis that compares the efficiency of the old and new units for the following reasons:

- The vendor of the proposed new unit was contacted several times for information regarding the efficiency of the unit, but was unable to provide any information to Yukon Electrical.
- Yukon Electrical measures efficiency at the plant level and does not track the efficiency of each individual unit. As a result, there is no data on the current unit with which to compare the new unit's efficiency (if it were available).

Yukon Electrical notes that new diesel engines have to meet improved emission standards. This often means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power performance.

The primary driver for this project is the need for a new unit due to the end of life condition of the existing unit, not increased efficiency. As a result,

Yukon Electrical has not incorporated efficiency into its business case for the need for this project.

As the change in efficiency resulting from the new unit is not currently known, no changes in efficiency have been incorporated into the diesel fuel forecast for the test years 2013-2015. Any increases or decreases in efficiency will be factored into a future application, once the unit is operational and the impact on overall efficiency for the Old Crow plant is known.

CW-YECL-23

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 23

In Business Case 23, YECL proposes to build a double circuit to accommodate a new Yukon Energy (YEC) supply source. The City requires information to assess the proposed capital.

Request:

(a) Please provide the latest status of the Yukon Energy Supply Source. Has approval been received by YEC; has construction started? What is the latest estimate of an in-service date for the new supply?

Response:

(a) Yukon Electrical is not aware of the approval status of YEC's project. Yukon Energy's construction at the new supply site is well underway and during inter-utility meetings, the in-service date was forecast to be by the end of 2014.

CW-YECL-24

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 24

In Business Case 24 YECL indicates that this project has been in the YECL long term plan since 1996.

Request:

(a) Please fully explain why this project must be undertaken in the test period, and was not started in 2011 or 2012.

(b) Please provide an analysis comparing load and capacity in downtown Whitehorse for each year from 1996 to 2015. In the response, please include total load, and peak load.

Response:

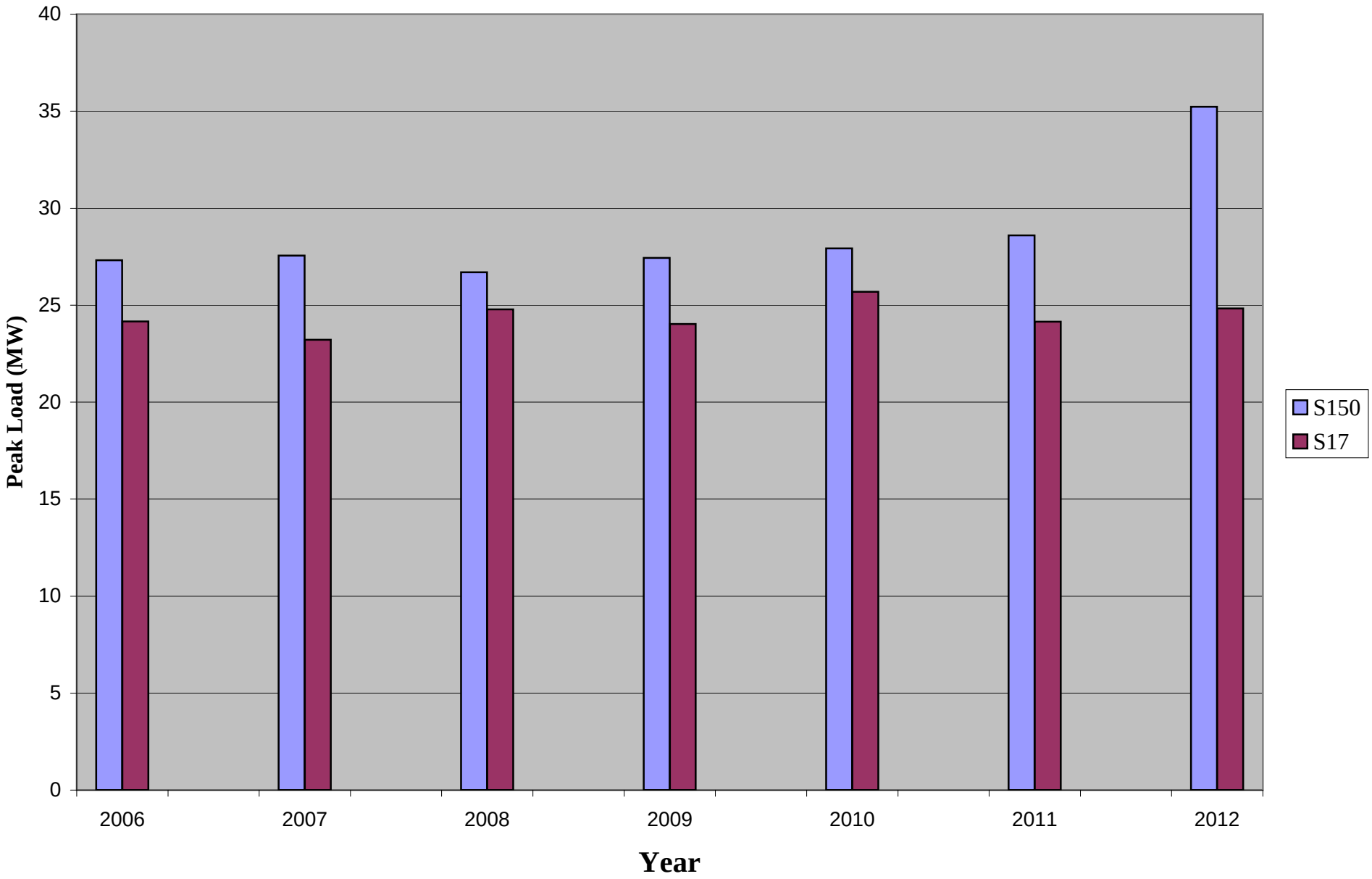
(a) As stated in the business case, this project has been considered for many years by Yukon Electrical. The downtown core of Whitehorse is a dense concentration of significant system loading on the Whitehorse distribution system. Preparation and planning has been completed in the past. With the significant increase in loading of the downtown core, there are many distribution lines near their design maximum in winter. This is a multiyear project that needs to be implemented in 2014 to successfully manage to existing load and the forecast load growth in the area in the future.

(b) Please refer to CW-YECL-24 Attachment 1 for peak loading for the 2006 through 2012 timeframe for Whitehorse. Yukon Electrical designs electrical infrastructure to accommodate peak loading. This timeline for peak loading is consistent with the needs identified in Business Case #24. During repair and upgrades to Yukon Electrical's SCADA dispatch computer and programs, historical loading information was damaged and not retrievable prior to 2006. In an effort to accommodate the request to provide information to 1996, Yukon Electrical contacted Yukon Energy for any loading information they may have; however, their loading information was not specific to the request.

As shown in CW-YECL-24 Attachment 1, peak load increased 17% from 2006 to 2012 with the most notable increase from 2011 to 2012 of 14%. This peak

loading is coincidental with the development of the downtown core. Yukon Electrical has provided the load charts for the Whitehorse area as the downtown core is supplied by multiple substations and lines. The area is the most significant and densely loaded section of the Whitehorse distribution system. The installation of electrical heat in multi residential and condominium developments continues to effect growth in loading in Downtown Whitehorse.

Whitehorse Peak Load



CW-YECL-25

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 27

In Business Case 27, YECL provides an analysis of its proposed AMR project. The City requires information to assess the business case.

Request:

(a) Please provide Attachment 1 in Excel format with formulae and links intact.

(b) Please fully explain why the depreciation rate for AMR of 7.13% is lower than that for conventional meter reading of 8.09%. In the response, please provide the currently approved depreciation rates for meters and for meter reading equipment.

(c) Please explain why the AMR option is based on 26 years of costs, yet the conventional option is based on 25 years of costs.

(d) Please provide the actual cost of "Manual Meter Reading", "Meter Tests", "Customer Applications and Service Orders", and "Data Cap Costs" for 2008, 2009, 2010, 2011, and 2012.

(e) Please produce two sensitivities, one with the capital cost of AMR 10% higher than forecast, and one with capital costs of AMR 20% higher than forecast. Please provide the response in Excel format with formulae and links intact.

Response:

(a) Please refer to YUB-YECL-48(m) Attachment 1 for the excel version of Business Case #27 – AMR, Attachment 1.

(b) As shown in Section 7, Attachment 1, page 196, the depreciation parameters for Meters (47610) are a L0 Iowa curve with a 15 year average service life (ASL) and for AMR (47630) an R2.5 Iowa curve with a 15 year average service life. The Iowa 15-L0 and Iowa 15-R2.5 are visually depicted in Section 7, Attachment 1, Pages 88 and 90 respectively. Although both Iowa curves have a 15 year average service life, the retirement dispersion around the 15 year

ASL's are significantly different between the two Iowa curves. The LO dispersion is fairly straight up to age 20 and then extends out to a maximum life of over 45 years. This is in contrast to the R2.5 dispersion which is more rectangular in shape with a maximum life of approximately 26 years. Furthermore, the composite depreciation rates described in this information request are developed from vintage depreciation rates applied to the vintage original costs as shown in Section 7, Attachment 1, pages 193-194 for Account 47610 and page 195 for Account 47630. As can be seen, the vintage distribution of investment for 47610-Meters is from 1970 to 2011 in contrast to 47630-AMR with a vintage distribution of investment of 2007-2011. This difference in retirement dispersions between the two fixed asset accounts combined with the significant differences between vintage original costs between the two accounts has caused the composite depreciation rates differences as described in the information request.

(c) The AMR analysis provides information for 26 years; however, the actual present value calculations for both options are based on 25 years. This can be verified by the excel version of Business Case #27 – AMR, Attachment 1, which can be found in YUB-YECL-48(m) Attachment 1.

(d) Please see table below for the actual costs ($000):

	Ref:	2008	2009	2010	2011	2012
Manual Meter Reading	Sch 5.1 L.31	530	543	532	462	484
Meter Tests	Sch 5.3 L.2	31	31	39	46	48
Customer Applications and Service Orders	Sch 5.1 L.30	356	447	410	410	444
Data Cap Costs [(1)]	Sch 5.3 L.4	46	36	10	13	14
		963	1,057	991	931	990

[(1)] 2012 Costs per Sch 5.3, L.4, excluding $19 for other charges

(e) Please refer to CW-YECL-25(e) Attachments 1 and 2 for the AMR sensitivity analysis assuming the forecasted capital cost of AMR is 10% and 20% higher. Yukon Electrical can confirm that the AMR analysis as filed included a capital cost contingency of 10%.

Cost Comparison: Yukon Electrical AMR Project with 10% increase to Capital

General Assumptions:

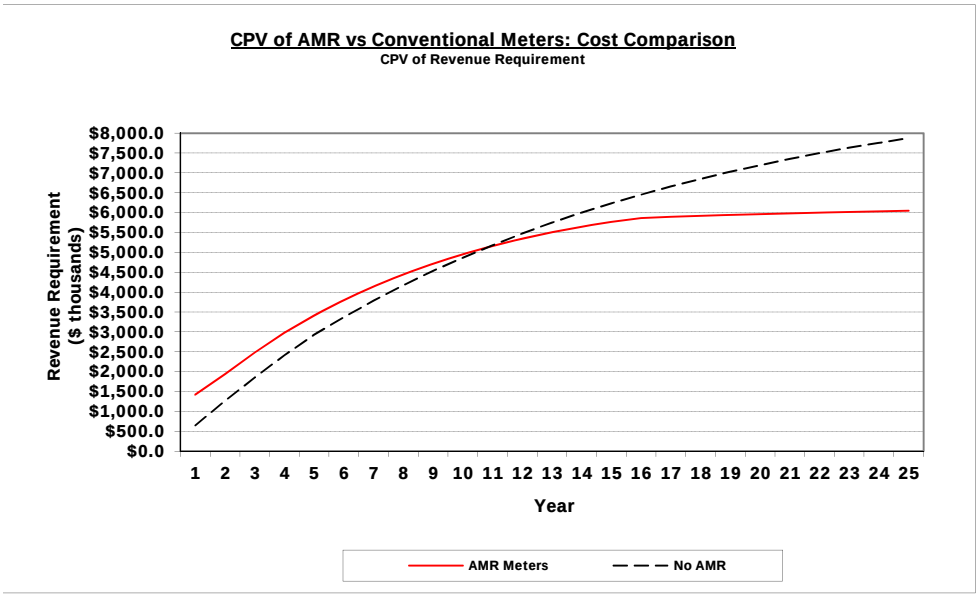
1. Analysis is over 25 years
2. AMR Implementation is over 2 years
3. Escalation Rate 2%
4. Analysis is on an incremental basis
5. Sunk capital costs are ignored
6. Future meter replacement costs are included

	AMR Meters	No AMR
Revenue Requirement		
CPV @ Year 5 *(thousands)*	**$3,409.8**	**$2,924.8**
CPV @ Year 25 *(thousands)*	**$6,047.5**	**$7,878.5**

2014/2015 Capital Cost Summary *(thousands)*	AMR Meters	No AMR
Generation Incremental		
Generation Existing		
Distribution	**$4,249.1**	**$313.2**
Transmission		
Total	**$4,249.1**	**$313.2**

Societal

Year	AMR Meters	No AMR
1	$1,419.0	$650.0
2	$1,932.0	$1,267.2
3	$2,483.3	$1,852.6
4	$2,973.8	$2,407.4
5	$3,409.8	$2,924.8
6	$3,796.9	$3,369.6
7	$4,140.2	$3,784.3
8	$4,444.1	$4,171.1
9	$4,713.0	$4,531.8
10	$4,950.3	$4,868.3
11	$5,159.5	$5,182.2
12	$5,343.5	$5,475.1
13	$5,505.0	$5,748.3
14	$5,646.4	$6,003.3
15	$5,765.0	$6,236.5
16	$5,861.4	$6,454.2
17	$5,894.5	$6,657.8
18	$5,918.4	$6,848.3
19	$5,940.7	$7,026.5
20	$5,961.6	$7,193.2
21	$5,981.2	$7,349.1
22	$5,999.4	$7,495.0
23	$6,016.5	$7,631.4
24	$6,032.5	$7,759.1
25	$6,047.5	$7,878.5



Assumptions: Yukon Electrical AMR Project with 10% increase to Capital
AMR Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.03248
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.04052
TOTALS			9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **7.13%**

D Escalation Rate **2.0%**

E US Exchange Rate **1.00**

F All analysis are based on 26 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Total number of AMR Meters **14,482 YECL** 192,796

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*

Input Starting Construction Year **Jan-14**

J **METERS:**		Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40
# of Residential Meters to be installed			6,343	6,560	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
# of Commercial Meters to be installed			0	1579	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
# Spare Residential Meters		0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
# Spare Commerical Meters		0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 Cost of Residential Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2 Cost of Residential AMR Module		$126.50 /meter	$802,390	$829,840	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748	$27,748
3 Cost of Commercial Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Cost of Commercial AMR Module	=	$489.50 /meter	$0	$772,921	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594	$11,594
5 Installation - Residential Meters		$18.15 /meter	$115,125	$119,064	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981	$3,981
6 Installation - Commerical Meters		$225.50 /meter	$0	$356,065	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341	$5,341
7 Freight		$11.00 /meter	$69,773	$89,529	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673	$2,673
8 Billing System Configuration			$275,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10 Retrofitting Costs		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11 Meter Read Verification	5%	$39.60 /hr	$12,559	$16,115	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481	$481
12 Test Set & Spares Equipment			$22,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13 Contingency	10%		$129,685	$218,353	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182	$5,182
14 Project Management	5%		$64,842	$109,177	$2,591	$2,591	$2,591	$2,591	$2,591	$2,591	$2,591	$2,591	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$1,491,374	$2,511,063	$59,591	$59,591	$59,591	$59,591	$59,591	$59,591	$59,591	$59,591	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000	$57,000
K **SUBSTATIONS:**																													
# of Substations required			2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials			$176,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16 Installation by YECL			$38,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17 Contingency	10%		$21,450	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18 Project Management	5%		$10,725	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$246,675	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL Capital			**$1,738,049**	**$2,511,063**	**$59,591**	**$59,591**	**$59,591**	**$59,591**	**$59,591**	**$59,591**	**$59,591**	**$59,591**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**	**$57,000**
L **Allocated AMR O&M Costs:** *includes contingency of* *25%*																													
19 O&M Acct#71212 - DCSI TNS Maintenance Support		$0.44 /meter	$0	$2,791	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582
20 O&M Acct#71214 - Annual Sample Verification Process		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21 O&M Acct#72107 - I-Tek User Fees (Email & Server Storage		$0.13 /meter	$0	$823	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645
22 O&M Acct#72109 - PCs & Monitors		$0.09 /meter	$0	$600	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201
23 O&M Acct#72118 - I-Tek Support for TNS Server		$0.69 /meter	$0	$4,359	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719
24 Labour Acct#71211 - AMR Meter Reading		$1.57 /meter	$0	$9,952	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905
25 Labour Acct#71214 - AMR Verification		$0.03 /meter	$0	$206	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411
26 Labour Acct#71215 - AMR Substation Troubleshoot & Suppc		$0.71 /meter	$0	$4,504	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007
27 Labour Acct# 71250 - AMR Special Meter Reading		$0.25 /meter	$0	$1,563	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126
28 Conventional Meter Read Costs	100%	of existing costs	$689,400	$617,400	$76,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29 Affiliate Charges																													
Subtotal			$689,400	$642,197	$126,395	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595
M **AMR O&M Savings / Revenue:**																													
29 Project Management			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30 Data-Cap Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31 Reduced Read-to-Bill Lag			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32 Manual Meter Reading Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33 Meter Test Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34 Special Read Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36 Labour Installation of Meters			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL O&M			**$689,400**	**$642,197**	**$126,395**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**
Total Cash Flow			**$2,427,449**	**$3,153,260**	**$185,986**	**$109,186**	**$109,186**	**$109,186**	**$109,186**	**$109,186**	**$109,186**	**$109,186**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**	**$106,595**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$802,390	$829,840	$28,869	$29,446	$30,035	$30,636	$31,249	$31,874	$32,511	$33,161	$33,825	$34,501	$35,191	$35,895	$36,613	$37,345	$38,092	$38,854	$39,631	$40,423	$41,232	$42,057	$42,898	$43,756	$44,631	$45,523	$46,434
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$772,921	$12,062	$12,303	$12,550	$12,801	$13,057	$13,318	$13,584	$13,856	$14,133	$14,415	$14,704	$14,998	$15,298	$15,604	$15,916	$16,234	$16,559	$16,890	$17,228	$17,572	$17,924	$18,282	$18,648	$19,021	$19,401
$115,125	$119,064	$4,142	$4,225	$4,309	$4,396	$4,484	$4,573	$4,665	$4,758	$4,853	$4,950	$5,049	$5,150	$5,253	$5,358	$5,465	$5,575	$5,686	$5,800	$5,916	$6,034	$6,155	$6,278	$6,404	$6,532	$6,662
$0	$356,065	$5,557	$5,668	$5,781	$5,897	$6,015	$6,135	$6,258	$6,383	$6,511	$6,641	$6,774	$6,909	$7,047	$7,188	$7,332	$7,479	$7,628	$7,781	$7,936	$8,095	$8,257	$8,422	$8,591	$8,762	$8,938
$69,773	$89,529	$2,781	$2,837	$2,894	$2,952	$3,011	$3,071	$3,132	$3,195	$3,259	$3,324	$3,391	$3,458	$3,527	$3,598	$3,670	$3,743	$3,818	$3,895	$3,973	$4,052	$4,133	$4,216	$4,300	$4,386	$4,474
$275,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$12,559	$16,115	$501	$511	$521	$531	$542	$553	$564	$575	$587	$598	$610	$622	$635	$648	$661	$674	$687	$701	$715	$729	$744	$759	$774	$789	$805
$22,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$129,685	$218,353	$5,391	$5,499	$5,609	$5,721	$5,836	$5,952	$6,071	$6,193	$6,317	$6,443	$6,572	$6,703	$6,837	$6,974	$7,114	$7,256	$7,401	$7,549	$7,700	$7,854	$8,011	$8,171	$8,335	$8,501	$8,671
$64,842	$109,177	$2,696	$2,750	$2,805	$2,861	$2,918	$2,976	$3,036	$3,096	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,491,374	$2,511,063	$61,999	$63,239	$64,504	$65,794	$67,109	$68,452	$69,821	$71,217	$69,483	$70,873	$72,290	$73,736	$75,211	$76,715	$78,249	$79,814	$81,411	$83,039	$84,700	$86,394	$88,121	$89,884	$91,681	$93,515	$95,385
$176,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$38,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$21,450	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$10,725	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$246,675	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,738,049	$2,561,284	$61,999	$63,239	$64,504	$65,794	$67,109	$68,452	$69,821	$71,217	$69,483	$70,873	$72,290	$73,736	$75,211	$76,715	$78,249	$79,814	$81,411	$83,039	$84,700	$86,394	$88,121	$89,884	$91,681	$93,515	$95,385
$0	$2,847	$5,807	$5,923	$6,042	$6,163	$6,286	$6,412	$6,540	$6,671	$6,804	$6,940	$7,079	$7,221	$7,365	$7,512	$7,663	$7,816	$7,972	$8,132	$8,294	$8,460	$8,629	$8,802	$8,978	$9,158	$9,341
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$839	$1,711	$1,746	$1,781	$1,816	$1,853	$1,890	$1,927	$1,966	$2,005	$2,045	$2,086	$2,128	$2,171	$2,214	$2,258	$2,303	$2,349	$2,396	$2,444	$2,493	$2,543	$2,594	$2,646	$2,699	$2,753
$0	$612	$1,249	$1,274	$1,300	$1,326	$1,352	$1,379	$1,407	$1,435	$1,464	$1,493	$1,523	$1,553	$1,584	$1,616	$1,649	$1,681	$1,715	$1,749	$1,784	$1,820	$1,856	$1,894	$1,931	$1,970	$2,010
$0	$4,446	$9,071	$9,252	$9,437	$9,626	$9,818	$10,015	$10,215	$10,419	$10,628	$10,840	$11,057	$11,278	$11,504	$11,734	$11,969	$12,208	$12,452	$12,701	$12,955	$13,214	$13,479	$13,748	$14,023	$14,304	$14,590
$0	$10,151	$20,709	$21,123	$21,545	$21,976	$22,416	$22,864	$23,321	$23,788	$24,264	$24,749	$25,244	$25,749	$26,264	$26,789	$27,325	$27,871	$28,429	$28,997	$29,577	$30,169	$30,772	$31,387	$32,015	$32,656	$33,309
$0	$210	$428	$436	$445	$454	$463	$472	$482	$491	$501	$511	$522	$532	$543	$553	$565	$576	$587	$599	$611	$623	$636	$649	$661	$675	$688
$0	$4,594	$9,371	$9,558	$9,750	$9,945	$10,143	$10,346	$10,553	$10,764	$10,980	$11,199	$11,423	$11,652	$11,885	$12,122	$12,365	$12,612	$12,864	$13,122	$13,384	$13,652	$13,925	$14,203	$14,487	$14,777	$15,073
$0	$1,594	$3,252	$3,317	$3,383	$3,451	$3,520	$3,590	$3,662	$3,735	$3,810	$3,886	$3,964	$4,043	$4,124	$4,207	$4,291	$4,376	$4,464	$4,553	$4,644	$4,737	$4,832	$4,929	$5,027	$5,128	$5,230
$689,400	$629,748	$79,903	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$2,427,449	$3,216,326	$193,500	$115,869	$118,186	$120,550	$122,961	$125,420	$127,929	$130,487	$129,939	$132,537	$135,188	$137,892	$140,650	$143,463	$146,332	$149,259	$152,244	$155,289	$158,394	$161,562	$164,794	$168,089	$171,451	$174,880	$178,378

Assumptions: Yukon Electrical AMR Project with 10% increase to Capital
Conventional Meter Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.0325
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.0405
TOTALS			9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **8.09%**

D Escalation Rate **2.0%**

E US Exchange Rate **1**

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Incremental Capital Cost:

Input Starting Construction Year: **Jan-14**

	Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40	Year 27 Jan-41	Year 28 Jan-42
# of Residential Meters to be installed/replaced		1,850	1,850	1,850	1,850	1,850	1,850	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
# of Commercial Meters to be installed/replaced		150	150	150	150	150	150	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
1 Cost of Residential Meter	$35.00 /meter	$64,750	$64,750	$64,750	$64,750	$64,750	$64,750	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000
2 Cost of Commercial Meter	#########	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
3 Installation - Residential Meters	$18.15 /meter	$33,578	$33,578	$33,578	$33,578	$33,578	$33,578	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260	$7,260
4 Installation - Commerical Meters	$55.00 /meter	$8,250	$8,250	$8,250	$8,250	$8,250	$8,250	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750
5 Freight Cost (in CDN)	$10.00 /meter	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500
6 Residential Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Commerical Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Retrofitting Costs	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Meter Read Verification	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$156,578	$156,578	$156,578	$156,578	$156,578	$156,578	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510	$38,510
TOTAL Capital		**$156,578**	**$156,578**	**$156,578**	**$156,578**	**$156,578**	**$156,578**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**	**$38,510**

I **Conventional O&M Costs:**

1 Manual Meter Reading Costs		$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800
2 Meter Test Costs	$36.40 /meter	$72,800	$72,800	$72,800	$72,800	$72,800	$72,800	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380
3 Customer Applications & Service Orders		$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000
4 Data Cap Costs		$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8																														
9																														
TOTAL O&M		**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,982**	**$632,984**
Total Cash Flow		**$845,978**	**$845,978**	**$845,978**	**$845,978**	**$845,978**	**$845,978**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,490**	**$671,492**	**$671,494**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41	Jan-42
$64,750	$66,045	$67,366	$68,713	$70,087	$71,489	$15,766	$16,082	$16,403	$16,731	$17,066	$17,407	$17,755	$18,110	$18,473	$18,842	$19,219	$19,603	$19,995	$20,395	$20,803	$21,219	$21,644	$22,077	$22,518	$22,968	$23,428	$23,896	$24,374
$30,000	$30,600	$31,212	$31,836	$32,473	$33,122	$11,262	$11,487	$11,717	$11,951	$12,190	$12,434	$12,682	$12,936	$13,195	$13,459	$13,728	$14,002	$14,282	$14,568	$14,859	$15,157	$15,460	$15,769	$16,084	$16,406	$16,734	$17,069	$17,410
$33,578	$34,249	$34,934	$35,633	$36,345	$37,072	$8,176	$8,339	$8,506	$8,676	$8,850	$9,027	$9,207	$9,392	$9,579	$9,771	$9,966	$10,166	$10,369	$10,576	$10,788	$11,004	$11,224	$11,448	$11,677	$11,911	$12,149	$12,392	$12,640
$8,250	$8,415	$8,583	$8,755	$8,930	$9,109	$3,097	$3,159	$3,222	$3,287	$3,352	$3,419	$3,488	$3,557	$3,629	$3,701	$3,775	$3,851	$3,928	$4,006	$4,086	$4,168	$4,251	$4,336	$4,423	$4,512	$4,602	$4,694	$4,788
$20,000	$20,400	$20,808	$21,224	$21,649	$22,082	$5,068	$5,169	$5,272	$5,378	$5,485	$5,595	$5,707	$5,821	$5,938	$6,056	$6,178	$6,301	$6,427	$6,556	$6,687	$6,820	$6,957	$7,096	$7,238	$7,383	$7,530	$7,681	$7,835
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$156,578	$159,709	$162,903	$166,161	$169,485	$172,874	$43,369	$44,236	$45,121	$46,023	$46,943	$47,882	$48,840	$49,817	$50,813	$51,829	$52,866	$53,923	$55,002	$56,102	$57,224	$58,368	$59,536	$60,726	$61,941	$63,180	$64,443	$65,732	$67,047
$156,578	$159,709	$162,903	$166,161	$169,485	$172,874	$43,369	$44,236	$45,121	$46,023	$46,943	$47,882	$48,840	$49,817	$50,813	$51,829	$52,866	$53,923	$55,002	$56,102	$57,224	$58,368	$59,536	$60,726	$61,941	$63,180	$64,443	$65,732	$67,047
$460,800	$470,016	$479,416	$489,005	$498,785	$508,760	$518,936	$529,314	$539,901	$550,699	$561,713	$572,947	$584,406	$596,094	$608,016	$620,176	$632,580	$645,231	$658,136	$671,299	$684,725	$698,419	$712,387	$726,635	$741,168	$755,991	$771,111	$786,533	$802,264
$72,800	$74,256	$75,741	$77,256	$78,801	$80,377	$18,447	$18,815	$19,192	$19,576	$19,967	$20,366	$20,774	$21,189	$21,613	$22,045	$22,486	$22,936	$23,395	$23,863	$24,340	$24,827	$25,323	$25,830	$26,346	$26,873	$27,411	$27,959	$28,518
$135,000	$137,700	$140,454	$143,263	$146,128	$149,051	$152,032	$155,073	$158,174	$161,337	$164,564	$167,856	$171,213	$174,637	$178,130	$181,692	$185,326	$189,033	$192,813	$196,670	$200,603	$204,615	$208,707	$212,881	$217,139	$221,482	$225,911	$230,430	$235,038
$20,800	$21,216	$21,640	$22,073	$22,515	$22,965	$23,424	$23,893	$24,371	$24,858	$25,355	$25,862	$26,379	$26,907	$27,445	$27,994	$28,554	$29,125	$29,708	$30,302	$30,908	$31,526	$32,156	$32,800	$33,455	$34,125	$34,807	$35,503	$36,213
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$703,188	$717,252	$731,597	$746,229	$761,153	$712,838	$727,095	$741,637	$756,470	$771,599	$787,031	$802,772	$818,827	$835,204	$851,908	$868,946	$886,325	$904,051	$922,132	$940,575	$959,386	$978,574	$998,146	$1,018,109	#######	$1,059,240	$1,080,428	$1,102,040
$845,978	$862,897	$880,155	$897,758	$915,713	$934,028	$756,207	$771,331	$786,758	$802,493	$818,543	$834,913	$851,612	$868,644	$886,017	$903,737	$921,812	$940,248	$959,053	$978,234	$997,799	#######	$1,038,110	#######	$1,080,050	#######	$1,123,684	$1,146,161	$1,169,087

Yukon Electrical AMR Project with 10 % increase to Capital
AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
1 Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Cost of Residential AMR Module	401,195	816,115	414,920	14,434	14,723	15,018	15,318	15,624	15,937	16,256	16,581	16,912	17,251	17,596	17,947	18,306	18,673	19,046	19,427	19,815	20,212	20,616	21,028	21,449	21,878	22,315	22,762	23,217
3 Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Cost of Commercial AMR Module	0	386,460	386,460	6,031	6,152	6,275	6,400	6,528	6,659	6,792	6,928	7,066	7,208	7,352	7,499	7,649	7,802	7,958	8,117	8,279	8,445	8,614	8,786	8,962	9,141	9,324	9,510	9,701
5 Installation - Residential Meters	57,563	117,095	59,532	2,071	2,112	2,155	2,198	2,242	2,287	2,332	2,379	2,427	2,475	2,525	2,575	2,627	2,679	2,733	2,787	2,843	2,900	2,958	3,017	3,077	3,139	3,202	3,266	3,331
6 Installation - Commerical Meters	0	178,032	178,032	2,778	2,834	2,891	2,948	3,007	3,068	3,129	3,191	3,255	3,320	3,387	3,455	3,524	3,594	3,666	3,739	3,814	3,890	3,968	4,048	4,129	4,211	4,295	4,381	4,469
7 Freight	34,887	79,651	44,765	1,391	1,419	1,447	1,476	1,505	1,535	1,566	1,597	1,629	1,662	1,695	1,729	1,764	1,799	1,835	1,872	1,909	1,947	1,986	2,026	2,067	2,108	2,150	2,193	2,237
8 Billing System Configuration	137,500	137,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Meter Read Verification	6,280	14,337	8,058	250	255	260	266	271	276	282	288	293	299	305	311	317	324	330	337	344	351	358	365	372	379	387	395	403
12 Test Set & Spares Equipment	11,000	11,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Contingency	64,842	174,019	109,177	2,696	2,750	2,805	2,861	2,918	2,976	3,036	3,096	3,158	3,221	3,286	3,352	3,419	3,487	3,557	3,628	3,700	3,774	3,850	3,927	4,006	4,086	4,167	4,251	4,336
14 Project Management	32,421	87,010	54,588	1,348	1,375	1,402	1,430	1,459	1,488	1,518	1,548	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials	88,000	88,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Installation by YECL	19,250	19,250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Contingency	10,725	10,725	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Project Management	5,363	5,363	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	869,025	2,124,556	1,255,532	30,999	31,619	32,252	32,897	33,555	34,226	34,910	35,609	34,742	35,436	36,145	36,868	37,605	38,357	39,125	39,907	40,705	41,519	42,350	43,197	44,061	44,942	45,841	46,758	47,693

Operations & Maintenance:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Allocated AMR O&M Costs:																												
19 O&M Acct#71212 - DCSI TNS Maintenanc	0	2,847	5,807	5,923	6,042	6,163	6,286	6,412	6,540	6,671	6,804	6,940	7,079	7,221	7,365	7,512	7,663	7,816	7,972	8,132	8,294	8,460	8,629	8,802	8,978	9,158	0	0
20 O&M Acct#71214 - Annual Sample Verifica	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 O&M Acct#72107 - I-Tek User Fees (Emai	0	839	1,711	1,746	1,781	1,816	1,853	1,890	1,927	1,966	2,005	2,045	2,086	2,128	2,171	2,214	2,258	2,303	2,349	2,396	2,444	2,493	2,543	2,594	2,646	2,699	0	0
22 O&M Acct#72109 - PCs & Monitors	0	612	1,249	1,274	1,300	1,326	1,352	1,379	1,407	1,435	1,464	1,493	1,523	1,553	1,584	1,616	1,649	1,681	1,715	1,749	1,784	1,820	1,856	1,894	1,931	1,970	0	0
23 O&M Acct#72118 - I-Tek Support for TNS	0	4,446	9,071	9,252	9,437	9,626	9,818	10,015	10,215	10,419	10,628	10,840	11,057	11,278	11,504	11,734	11,969	12,208	12,452	12,701	12,955	13,214	13,479	13,748	14,023	14,304	0	0
24 Labour Acct#71211 - AMR Meter Reading	0	10,151	20,709	21,123	21,545	21,976	22,416	22,864	23,321	23,788	24,264	24,749	25,244	25,749	26,264	26,789	27,325	27,871	28,429	28,997	29,577	30,169	30,772	31,387	32,015	32,656	0	0
25 Labour Acct#71214 - AMR Verification	0	210	428	436	445	454	463	472	482	491	501	511	522	532	543	553	565	576	587	599	611	623	636	649	661	675	0	0
26 Labour Acct#71215 - AMR Substation Trou	0	4,594	9,371	9,558	9,750	9,945	10,143	10,346	10,553	10,764	10,980	11,199	11,423	11,652	11,885	12,122	12,365	12,612	12,864	13,122	13,384	13,652	13,925	14,203	14,487	14,777	0	0
27 Labour Acct# 71250 - AMR Special Meter I	0	1,594	3,252	3,317	3,383	3,451	3,520	3,590	3,662	3,735	3,810	3,886	3,964	4,043	4,124	4,207	4,291	4,376	4,464	4,553	4,644	4,737	4,832	4,929	5,027	5,128	0	0
28 Conventional Meter Read Costs	689,400	629,748	79,903	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Affiliate Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AMR O&M Savings / Revenue:																												
29 Project Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Data-Cap Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Reduced Read-to-Bill Lag	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Manual Meter Reading Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	689,400	655,041	131,501	52,630	53,683	54,756	55,852	56,969	58,108	59,270	60,455	61,665	62,898	64,156	65,439	66,748	68,083	69,444	70,833	72,250	73,695	75,169	76,672	78,206	79,770	81,365	0	0

Yukon Electrical AMR Project with 10 % increase to Capital

AMR Cost Impact

Year		Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:		**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																													
Cost of Residential Meter		7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module		7.130%	28,605	86,794	116,378	117,407	118,457	119,528	120,620	121,734	122,870	124,029	125,211	126,417	127,647	128,902	130,181	130,657	18,699	19,073	19,454	19,843	20,240	20,645	21,058	21,479	21,908	22,347	22,794
Cost of Commercial Meter		7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module		7.130%	0	27,555	55,109	55,539	55,978	56,425	56,882	57,347	57,822	58,306	58,800	59,304	59,818	60,342	60,877	61,422	28,292	7,969	8,128	8,291	8,457	8,626	8,798	8,974	9,154	9,337	9,524
Installation - Residential Meters		7.130%	4,104	12,453	16,698	16,845	16,996	17,150	17,306	17,466	17,629	17,795	17,965	18,138	18,315	18,495	18,678	18,746	2,683	2,737	2,791	2,847	2,904	2,962	3,021	3,082	3,143	3,206	3,270
Installation - Commerical Meters		7.130%	0	12,694	25,387	25,585	25,788	25,994	26,204	26,418	26,637	26,860	27,088	27,320	27,557	27,798	28,044	28,296	13,033	3,671	3,745	3,819	3,896	3,974	4,053	4,134	4,217	4,301	4,387
Freight		7.130%	2,487	8,167	11,358	11,457	11,559	11,662	11,767	11,874	11,984	12,095	12,209	12,325	12,444	12,565	12,688	12,814	2,189	1,838	1,874	1,912	1,950	1,989	2,029	2,069	2,111	2,153	2,196
Billing System Configuration		7.130%	9,804	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	19,608	10,299	0	0	0	0	0	0	0	0	0	0	0	0
	0	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs		7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification		7.130%	448	1,470	2,044	2,062	2,081	2,099	2,118	2,137	2,157	2,177	2,198	2,219	2,240	2,262	2,284	2,307	394	331	337	344	351	358	365	372	380	388	395
Test Set & Spares Equipment		7.130%	784	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	824	0	0	0	0	0	0	0	0	0	0	0	0
Contingency		7.130%	4,623	17,031	24,815	25,007	25,203	25,403	25,607	25,815	26,028	26,244	26,465	26,690	26,920	27,154	27,393	27,456	3,492	3,562	3,633	3,706	3,780	3,855	3,932	4,011	4,091	4,173	4,257
Project Management		7.130%	2,312	8,515	12,408	12,504	12,602	12,702	12,804	12,908	13,014	13,122	13,232	13,232	13,232	13,232	13,232	6,537	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:																													
Aclara SCE materials		7.130%	6,274	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	12,549	6,591	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL		7.130%	1,373	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	2,745	1,442	0	0	0	0	0	0	0	0	0	0	0	0
Contingency		7.130%	765	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	803	0	0	0	0	0	0	0	0	0	0	0	0
Project Management		7.130%	382	765	765	765	765	765	765	765	765	765	765	765	765	765	402	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation			61,961	213,442	302,962	305,172	307,426	309,726	312,072	314,464	316,904	319,393	321,932	324,409	326,936	329,513	313,738	288,233	68,782	39,179	39,963	40,762	41,577	42,409	43,257	44,122	45,005	45,905	46,823

ACCUMULATED DEPRECIATION:		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module		0	28,605	115,399	231,777	349,184	467,641	587,169	707,789	829,523	952,393	1,076,422	1,201,633	1,328,051	1,455,698	1,584,599	1,714,781	1,845,437	1,864,136	1,883,209	1,902,663	1,922,506	1,942,746	1,963,390	1,984,448	2,005,927	2,027,835	2,050,182	2,072,975
Cost of Commercial Meter		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module		0	0	27,555	82,664	138,203	194,181	250,606	307,488	364,835	422,657	480,963	539,763	599,067	658,885	719,227	780,103	841,525	869,817	877,786	885,915	894,206	902,662	911,288	920,087	929,061	938,215	947,552	957,076
Installation - Residential Meters		0	4,104	16,557	33,255	50,100	67,096	84,246	101,552	119,018	136,648	154,443	172,408	190,546	208,861	227,356	246,034	264,780	267,463	270,199	272,991	275,838	278,742	281,704	284,725	287,807	290,950	294,156	297,427
Installation - Commerical Meters		0	0	12,694	38,081	63,667	89,454	115,448	141,652	168,070	194,707	221,567	248,655	275,975	303,531	331,329	359,373	387,669	400,702	404,373	408,118	411,937	415,833	419,807	423,860	427,994	432,211	436,513	440,900
Freight		0	2,487	10,654	22,012	33,470	45,028	56,690	68,457	80,331	92,315	104,410	116,619	128,945	141,389	153,954	166,642	179,456	181,645	183,483	185,357	187,269	189,219	191,208	193,237	195,306	197,417	199,570	201,766
Billing System Configuration		0	9,804	29,411	49,019	68,626	88,234	107,841	127,449	147,056	166,664	186,271	205,879	225,486	245,094	264,701	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000	275,000
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification		0	448	1,918	3,962	6,025	8,105	10,204	12,322	14,460	16,617	18,794	20,991	23,210	25,450	27,712	29,996	32,302	32,696	33,027	33,364	33,708	34,059	34,417	34,783	35,155	35,535	35,923	36,318
Test Set & Spares Equipment		0	784	2,353	3,922	5,490	7,059	8,627	10,196	11,765	13,333	14,902	16,470	18,039	19,608	21,176	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000
Contingency		0	4,623	21,654	46,469	71,476	96,680	122,083	147,690	173,506	199,533	225,777	252,242	278,932	305,851	333,005	360,398	387,854	391,346	394,908	398,541	402,246	406,026	409,881	413,814	417,825	421,916	426,090	430,346
Project Management		0	2,312	10,827	23,235	35,738	48,340	61,042	73,845	86,753	99,767	112,889	126,121	139,353	152,586	165,818	179,050	185,587	185,587	185,587	185,587	185,587	185,587	185,587	185,587	185,587	185,587	185,587	185,587
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials		0	6,274	18,823	31,372	43,921	56,470	69,018	81,567	94,116	106,665	119,214	131,762	144,311	156,860	169,409	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000	176,000
Installation by YECL		0	1,373	4,118	6,863	9,608	12,353	15,098	17,843	20,588	23,333	26,078	28,823	31,568	34,313	37,058	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500	38,500
Contingency		0	765	2,294	3,823	5,353	6,882	8,412	9,941	11,470	13,000	14,529	16,059	17,588	19,117	20,647	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450	21,450
Project Management		0	382	1,147	1,912	2,676	3,441	4,206	4,971	5,735	6,500	7,265	8,029	8,794	9,559	10,323	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725	10,725
			61,961	275,404	578,365	883,537	1,190,964	1,500,690	1,812,761	2,127,225	2,444,130	2,763,523	3,085,455	3,409,865	3,736,801	4,066,314	4,380,052	4,668,285	4,737,067	4,776,246	4,816,209	4,856,971	4,898,549	4,940,958	4,984,215	5,028,337	5,073,342	5,119,247	5,166,070

PROPERTY IN SERVICE (beg yr):		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module		0	401,195	1,188,704	1,516,830	1,414,887	1,312,203	1,208,763	1,104,554	999,558	893,761	787,147	679,698	571,399	462,232	352,181	241,226	129,351	17,367	17,715	18,069	18,430	18,799	19,175	19,558	19,950	20,349	20,756	21,171
Cost of Commercial Meter		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module		0	0	386,460	745,366	696,288	646,900	597,197	547,172	496,819	446,131	395,101	343,722	291,989	239,893	187,427	134,584	81,356	27,736	7,402	7,550	7,701	7,855	8,012	8,172	8,336	8,502	8,672	8,846
Installation - Residential Meters		0	57,563	170,553	217,632	203,005	188,273	173,431	158,479	143,415	128,235	112,938	97,522	81,983	66,320	50,530	34,611	18,559	2,492	2,542	2,593	2,644	2,697	2,751	2,806	2,862	2,920	2,978	3,038
Installation - Commerical Meters		0	0	178,032	343,371	320,762	298,010	275,113	252,068	228,872	205,521	182,013	158,344	134,512	110,512	86,343	61,999	37,479	12,777	3,410	3,478	3,548	3,619	3,691	3,765	3,840	3,917	3,995	4,075
Freight		0	34,887	112,050	148,648	138,681	128,642	118,530	108,344	98,083	87,744	77,326	66,828	56,248	45,585	34,836	24,001	13,076	2,061	1,707	1,741	1,776	1,811	1,847	1,884	1,922	1,961	2,000	2,040
Billing System Configuration		0	137,500	265,196	245,589	225,981	206,374	186,766	167,159	147,551	127,944	108,336	88,729	69,121	49,514	29,906	10,299	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification		0	6,280	20,169	26,757	24,962	23,155	21,335	19,502	17,655	15,794	13,919	12,029	10,125	8,205	6,271	4,320	2,354	371	307	313	320	326	333	339	346	353	360	367
Test Set & Spares Equipment		0	11,000	21,216	19,647	18,079	16,510	14,941	13,373	11,804	10,236	8,667	7,098	5,530	3,961	2,393	824	0	0	0	0	0	0	0	0	0	0	0	0
Contingency		0	64,842	234,238	326,384	304,264	282,007	259,608	237,065	214,376	191,536	168,545	145,397	122,091	98,622	74,989	51,186	27,212	3,243	3,308	3,374	3,442	3,511	3,581	3,653	3,726	3,800	3,876	3,954
Project Management		0	32,421	117,119	163,192	152,132	141,003	129,804	118,533	107,188	95,768	84,272	72,699	59,466	46,234	33,001	19,769	6,537	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials		0	88,000	169,726	157,177	144,628	132,079	119,530	106,982	94,433	81,884	69,335	56,786	44,238	31,689	19,140	6,591	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL		0	19,250	37,127	34,382	31,637	28,892	26,147	23,402	20,657	17,912	15,167	12,422	9,677	6,932	4,187	1,442	0	0	0	0	0	0	0	0	0	0	0	0
Contingency		0	10,725	20,685	19,156	17,627	16,097	14,568	13,038	11,509	9,980	8,450	6,921	5,391	3,862	2,333	803	0	0	0	0	0	0	0	0	0	0	0	0
Project Management		0	5,363	10,343	9,578	8,813	8,049	7,284	6,519	5,754	4,990	4,225	3,460	2,696	1,931	1,166	402	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase		0	869,025	2,931,619	3,973,709	3,701,746	3,428,194	3,153,019	2,876,190	2,597,673	2,317,435	2,035,441	1,751,656	1,464,465	1,175,492	884,702	592,057	315,924	66,048	36,391	37,119	37,861	38,618	39,390	40,178	40,982	41,801	42,637	43,490

Yukon Electrical AMR Project with 10 % incre
AMR Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	30.000%		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037 %	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	689,400	689,400	0	(689,400)	(689,400)	0
1	Jan-15	869,025	63,442	61,961	15,093	655,041	795,538	0	(795,538)	(1,419,002)	1
2	Jan-16	2,931,619	214,020	213,442	50,915	131,501	609,878	0	(609,878)	(1,931,975)	2
3	Jan-17	3,973,709	290,097	302,962	69,013	52,630	714,702	0	(714,702)	(2,483,292)	3
4	Jan-18	3,701,746	270,242	305,172	64,290	53,683	693,387	0	(693,387)	(2,973,835)	4
5	Jan-19	3,428,194	250,272	307,426	59,539	54,756	671,994	0	(671,994)	(3,409,842)	5
6	Jan-20	3,153,019	230,183	309,726	54,760	55,852	650,520	0	(650,520)	(3,796,934)	6
7	Jan-21	2,876,190	209,973	312,072	49,952	56,969	628,965	0	(628,965)	(4,140,180)	7
8	Jan-22	2,597,673	189,641	314,464	45,115	58,108	607,327	0	(607,327)	(4,444,147)	8
9	Jan-23	2,317,435	169,182	316,904	40,248	59,270	585,604	0	(585,604)	(4,712,950)	9
10	Jan-24	2,035,441	148,595	319,393	35,350	60,455	563,795	0	(563,795)	(4,950,293)	10
11	Jan-25	1,751,656	127,878	321,932	30,422	61,665	541,897	0	(541,897)	(5,159,510)	11
12	Jan-26	1,464,465	106,912	324,409	25,434	62,898	519,653	0	(519,653)	(5,343,511)	12
13	Jan-27	1,175,492	85,816	326,936	20,415	64,156	497,323	0	(497,323)	(5,505,010)	13
14	Jan-28	884,702	64,587	329,513	15,365	65,439	474,904	0	(474,904)	(5,646,447)	14
15	Jan-29	592,057	43,222	313,738	10,282	66,748	433,991	0	(433,991)	(5,764,987)	15
16	Jan-30	315,924	23,064	288,233	5,487	68,083	384,866	0	(384,866)	(5,861,396)	16
17	Jan-31	66,048	4,822	68,782	1,147	69,444	144,195	0	(144,195)	(5,894,524)	17
18	Jan-32	36,391	2,657	39,179	632	70,833	113,301	0	(113,301)	(5,918,396)	18
19	Jan-33	37,119	2,710	39,963	645	72,250	115,567	0	(115,567)	(5,940,727)	19
20	Jan-34	37,861	2,764	40,762	658	73,695	117,879	0	(117,879)	(5,961,618)	20
21	Jan-35	38,618	2,819	41,577	671	75,169	120,236	0	(120,236)	(5,981,160)	21
22	Jan-36	39,390	2,876	42,409	684	76,672	122,641	0	(122,641)	(5,999,441)	22
23	Jan-37	40,178	2,933	43,257	698	78,206	125,094	0	(125,094)	(6,016,542)	23
24	Jan-38	40,982	2,992	44,122	712	79,770	127,596	0	(127,596)	(6,032,539)	24
25	Jan-39	41,801	3,052	45,005	726	81,365	130,148	0	(130,148)	(6,047,504)	25
26	Jan-40	42,637	3,113	45,905	741	0	49,758	0	(49,758)	(6,052,751)	26
27	Jan-41	43,490	3,175	46,823	755	0	50,753	0	(50,753)	(6,057,660)	27
28	Jan-42	44,360	3,238	47,759	770	0	51,768	0	(51,768)	(6,062,252)	28
29	Jan-43	(3,399)	(248)	(3,400)	(59)	0	(3,708)	0	3,708	(6,061,950)	29
30	Jan-44	1	0	0	0	0	0	0	(0)	(6,061,950)	30
31	Jan-45	1	0	0	0	0	0	0	(0)	(6,061,950)	31
32	Jan-46	1	0	0	0	0	0	0	(0)	(6,061,950)	32
33	Jan-47	1	0	0	0	0	0	0	(0)	(6,061,950)	33
34	Jan-48	1	0	0	0	0	0	0	(0)	(6,061,950)	34
35	Jan-49	1	0	0	0	0	0	0	(0)	(6,061,950)	35
36	Jan-50	1	0	0	0	0	0	0	(0)	(6,061,950)	36
37	Jan-51	1	0	0	0	0	0	0	(0)	(6,061,950)	37
38	Jan-52	1	0	0	0	0	0	0	(0)	(6,061,950)	38
39	Jan-53	1	0	0	0	0	0	0	(0)	(6,061,950)	39
40	Jan-54	1	0	0	0	0	0	0	(0)	(6,061,950)	40

Yukon Electrical AMR Project with 10% increase to Capital
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

O&M:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Manual Meter Reading Costs	0	470,016	479,416	489,005	498,785	508,760	518,936	529,314	539,901	550,699	561,713	572,947	584,406	596,094	608,016	620,176	632,580	645,231	658,136	671,299	684,725	698,419	712,387	726,635	741,168	755,991	771,111	786,533
Meter Test Costs	0	74,256	75,741	77,256	78,801	80,377	18,447	18,815	19,192	19,576	19,967	20,366	20,774	21,189	21,613	22,045	22,486	22,936	23,395	23,863	24,340	24,827	25,323	25,830	26,346	26,873	27,411	27,959
Customer Applications & Service Or	0	137,700	140,454	143,263	146,128	149,051	152,032	155,073	158,174	161,337	164,564	167,856	171,213	174,637	178,130	181,692	185,326	189,033	192,813	196,670	200,603	204,615	208,707	212,881	217,139	221,482	225,911	230,430
Data Cap Costs	0	21,216	21,640	22,073	22,515	22,965	23,424	23,893	24,371	24,858	25,355	25,862	26,379	26,907	27,445	27,994	28,554	29,125	29,708	30,302	30,908	31,526	32,156	32,800	33,455	34,125	34,807	35,503
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	0	703,188	717,252	731,597	746,229	761,153	712,838	727,095	741,637	756,470	771,599	787,031	802,772	818,827	835,204	851,908	868,946	886,325	904,051	922,132	940,575	959,386	978,574	998,146	1,018,109	1,038,471	1,059,240	1,080,425

Yukon Electrical AMR Project with 10% increase to Capital
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	8.090%	2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0

ACCUMULATED DEPRECIATION	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	2,619	10,529	23,890	42,865	61,840	80,815	99,791	118,766	137,741	156,716	175,692	194,667	213,642	232,617	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PROPERTY IN SERVICE (beg yr	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0

Yukon Electrical AMR Project with 10%
Conventional Meter Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	#####		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	0	0	0	0	0	0
1	Jan-15	32,375	2,364	2,619	562	703,188	708,733	0	(708,733)	(649,992)	1
2	Jan-16	95,153	6,947	7,910	1,653	717,252	733,761	0	(733,761)	(1,267,163)	2
3	Jan-17	154,623	11,288	13,361	2,685	731,597	758,931	0	(758,931)	(1,852,599)	3
4	Jan-18	210,662	15,379	18,975	3,659	746,229	784,242	0	(784,242)	(2,407,419)	4
5	Jan-19	191,687	13,994	18,975	3,329	761,153	797,452	0	(797,452)	(2,924,825)	5
6	Jan-20	172,712	12,609	18,975	3,000	712,838	747,422	0	(747,422)	(3,369,578)	6
7	Jan-21	153,737	11,223	18,975	2,670	727,095	759,964	0	(759,964)	(3,784,314)	7
8	Jan-22	134,761	9,838	18,975	2,340	741,637	772,791	0	(772,791)	(4,171,096)	8
9	Jan-23	115,786	8,453	18,975	2,011	756,470	785,909	0	(785,909)	(4,531,842)	9
10	Jan-24	96,811	7,068	18,975	1,681	771,599	799,323	0	(799,323)	(4,868,337)	10
11	Jan-25	77,835	5,682	18,975	1,352	787,031	813,040	0	(813,040)	(5,182,238)	11
12	Jan-26	58,860	4,297	18,975	1,022	802,772	827,066	0	(827,066)	(5,475,089)	12
13	Jan-27	39,885	2,912	18,975	693	818,827	841,407	0	(841,407)	(5,748,325)	13
14	Jan-28	20,910	1,526	18,975	363	835,204	856,069	0	(856,069)	(6,003,282)	14
15	Jan-29	1,934	141	1,934	34	851,908	854,017	0	(854,017)	(6,236,547)	15
16	Jan-30	0	0	0	0	868,946	868,946	0	(868,946)	(6,454,218)	16
17	Jan-31	0	0	0	0	886,325	886,325	0	(886,325)	(6,657,841)	17
18	Jan-32	0	0	0	0	904,051	904,051	0	(904,051)	(6,848,323)	18
19	Jan-33	0	0	0	0	922,132	922,132	0	(922,132)	(7,026,511)	19
20	Jan-34	0	0	0	0	940,575	940,575	0	(940,575)	(7,193,199)	20
21	Jan-35	0	0	0	0	959,386	959,386	0	(959,386)	(7,349,129)	21
22	Jan-36	0	0	0	0	978,574	978,574	0	(978,574)	(7,494,995)	22
23	Jan-37	0	0	0	0	998,146	998,146	0	(998,146)	(7,631,448)	23
24	Jan-38	0	0	0	0	1,018,109	1,018,109	0	(1,018,109)	(7,759,094)	24
25	Jan-39	0	0	0	0	1,038,471	1,038,471	0	(1,038,471)	(7,878,501)	25
26	Jan-40	0	0	0	0	1,059,240	1,059,240	0	(1,059,240)	(7,990,203)	26
27	Jan-41	0	0	0	0	1,080,425	1,080,425	0	(1,080,425)	(8,094,695)	27
28	Jan-42	0	0	0	0	1,102,034	1,102,034	0	(1,102,034)	(8,192,443)	28
29	Jan-43	0	0	0	0	0	0	0	(0)	(8,192,443)	29
30	Jan-44	0	0	0	0	0	0	0	(0)	(8,192,443)	30
31	Jan-45	0	0	0	0	0	0	0	(0)	(8,192,443)	31
32	Jan-46	0	0	0	0	0	0	0	(0)	(8,192,443)	32
33	Jan-47	0	0	0	0	0	0	0	(0)	(8,192,443)	33
34	Jan-48	0	0	0	0	0	0	0	(0)	(8,192,443)	34
35	Jan-49	0	0	0	0	0	0	0	(0)	(8,192,443)	35
36	Jan-50	0	0	0	0	0	0	0	(0)	(8,192,443)	36
37	Jan-51	0	0	0	0	0	0	0	(0)	(8,192,443)	37
38	Jan-52	0	0	0	0	0	0	0	(0)	(8,192,443)	38
39	Jan-53	0	0	0	0	0	0	0	(0)	(8,192,443)	39
40	Jan-54	0	0	0	0	0	0	0	(0)	(8,192,443)	40

Cost Comparison: Yukon Electrical AMR Project with 20% increase to Capital

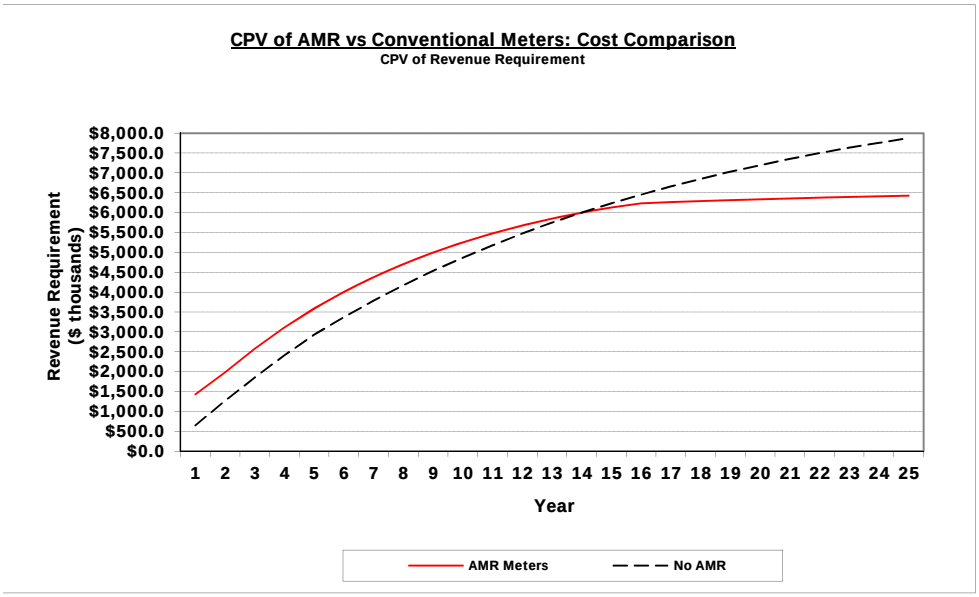
General Assumptions:
1. Analysis is over 25 years
2. AMR Implementation is over 2 years
3. Escalation Rate 2%
4. Analysis is on an incremental basis
5. Sunk capital costs are ignored
6. Future meter replacement costs are included

	AMR Meters	No AMR
Revenue Requirement		
CPV @ Year 5 *(thousands)*	**$3,582.1**	**$2,924.8**
CPV @ Year 25 *(thousands)*	**$6,425.1**	**$7,878.5**

2014/2015 Capital Cost Summary *(thousands)*	AMR Meters	No AMR
Generation Incremental		
Generation Existing		
Distribution	**$4,635.4**	**$319.3**
Transmission		
Total	**$4,635.4**	**$319.3**

Societal

Year	AMR Meters	No AMR
1	$1,430.7	$650.0
2	$1,980.3	$1,267.2
3	$2,578.0	$1,852.6
4	$3,109.7	$2,407.4
5	$3,582.1	$2,924.8
6	$4,001.4	$3,369.6
7	$4,373.0	$3,784.3
8	$4,702.0	$4,171.1
9	$4,992.7	$4,531.8
10	$5,249.3	$4,868.3
11	$5,475.4	$5,182.2
12	$5,674.1	$5,475.1
13	$5,848.4	$5,748.3
14	$6,000.9	$6,003.3
15	$6,128.6	$6,236.5
16	$6,232.2	$6,454.2
17	$6,266.9	$6,657.8
18	$6,291.6	$6,848.3
19	$6,314.7	$7,026.5
20	$6,336.3	$7,193.2
21	$6,356.5	$7,349.1
22	$6,375.4	$7,495.0
23	$6,393.1	$7,631.4
24	$6,409.6	$7,759.1
25	$6,425.1	$7,878.5



Assumptions: Yukon Electrical AMR Project with 20% increase to Capital
AMR Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.03248
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.04052
TOTALS			9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **7.13%**

D Escalation Rate **2.0%**

E US Exchange Rate **1.00**

F All analysis are based on 26 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Total number of AMR Meters **14,482 YECL** 192,796

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*
Input Starting Construction Year **Jan-14**

J **METERS:**	Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40
# of Residential Meters to be installed		6,343	6,560	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
# of Commercial Meters to be installed		0	1579	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
# Spare Residential Meters	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
# Spare Commerical Meters	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 Cost of Residential Meter	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2 Cost of Residential AMR Module	$138.00 /meter	$875,334	$905,280	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270	$30,270
3 Cost of Commercial Meter	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Cost of Commercial AMR Module =	$534.00 /meter	$0	$843,186	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648	$12,648
5 Installation - Residential Meters	$19.80 /meter	$125,591	$129,888	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343	$4,343
6 Installation - Commerical Meters	$246.00 /meter	$0	$388,434	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827	$5,827
7 Freight	$12.00 /meter	$76,116	$97,668	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916	$2,916
8 Billing System Configuration		$300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10 Retrofitting Costs	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11 Meter Read Verification 5%	$43.20 /hr	$13,701	$17,580	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525	$525
12 Test Set & Spares Equipment		$24,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13 Contingency 10%		$141,474	$238,203.62	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653	$5,653
14 Project Management 5%		$70,737.11	$119,101.81	$2,826	$2,826	$2,826	$2,826	$2,826	$2,826	$2,826	$2,826	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$1,626,954	$2,739,342	$65,009	$65,009	$65,009	$65,009	$65,009	$65,009	$65,009	$65,009	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182	$62,182
K **SUBSTATIONS:**																												
# of Substations required		2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials		$192,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16 Installation by YECL		$42,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17 Contingency 10%		$23,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18 Project Management 5%		$11,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$269,100	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL Capital		**$1,896,054**	**$2,739,342**	**$65,009**	**$65,009**	**$65,009**	**$65,009**	**$65,009**	**$65,009**	**$65,009**	**$65,009**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**	**$62,182**
L **Allocated AMR O&M Costs:** *includes contingency of 25%*																												
19 O&M Acct#71212 - DCSI TNS Maintenance Support	$0.44 /meter	$0	$2,791	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582
20 O&M Acct#71214 - Annual Sample Verification Process	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21 O&M Acct#72107 - I-Tek User Fees (Email & Server Storage	$0.13 /meter	$0	$823	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645
22 O&M Acct#72109 - PCs & Monitors	$0.09 /meter	$0	$600	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201
23 O&M Acct#72118 - I-Tek Support for TNS Server	$0.69 /meter	$0	$4,359	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719
24 Labour Acct#71211 - AMR Meter Reading	$1.57 /meter	$0	$9,952	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905
25 Labour Acct#71214 - AMR Verification	$0.03 /meter	$0	$206	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411
26 Labour Acct#71215 - AMR Substation Troubleshoot & Suppc	$0.71 /meter	$0	$4,504	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007
27 Labour Acct# 71250 - AMR Special Meter Reading	$0.25 /meter	$0	$1,563	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126
28 Conventional Meter Read Costs 100%	of existing costs	$689,400	$617,400	$76,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29 Affiliate Charges																												
Subtotal		$689,400	$642,197	$126,395	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595
M **AMR O&M Savings / Revenue:**																												
29 Project Management		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30 Data-Cap Savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31 Reduced Read-to-Bill Lag		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32 Manual Meter Reading Savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33 Meter Test Savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34 Special Read Savings		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36 Labour Installation of Meters		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL O&M		**$689,400**	**$642,197**	**$126,395**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**
Total Cash Flow		**$2,585,454**	**$3,381,539**	**$191,403**	**$114,603**	**$114,603**	**$114,603**	**$114,603**	**$114,603**	**$114,603**	**$114,603**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**	**$111,777**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$875,334	$905,280	$31,493	$32,123	$32,766	$33,421	$34,089	$34,771	$35,467	$36,176	$36,899	$37,637	$38,390	$39,158	$39,941	$40,740	$41,555	$42,386	$43,234	$44,098	$44,980	$45,880	$46,797	$47,733	$48,688	$49,662	$50,655
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$843,186	$13,159	$13,422	$13,690	$13,964	$14,243	$14,528	$14,819	$15,115	$15,418	$15,726	$16,040	$16,361	$16,688	$17,022	$17,363	$17,710	$18,064	$18,425	$18,794	$19,170	$19,553	$19,944	$20,343	$20,750	$21,165
$125,591	$129,888	$4,519	$4,609	$4,701	$4,795	$4,891	$4,989	$5,089	$5,190	$5,294	$5,400	$5,508	$5,618	$5,731	$5,845	$5,962	$6,081	$6,203	$6,327	$6,454	$6,583	$6,714	$6,849	$6,986	$7,125	$7,268
$0	$388,434	$6,062	$6,183	$6,307	$6,433	$6,562	$6,693	$6,827	$6,963	$7,102	$7,245	$7,389	$7,537	$7,688	$7,842	$7,999	$8,159	$8,322	$8,488	$8,658	$8,831	$9,008	$9,188	$9,372	$9,559	$9,750
$76,116	$97,668	$3,034	$3,095	$3,157	$3,220	$3,284	$3,350	$3,417	$3,485	$3,555	$3,626	$3,699	$3,773	$3,848	$3,925	$4,004	$4,084	$4,165	$4,249	$4,334	$4,420	$4,509	$4,599	$4,691	$4,785	$4,880
$300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$13,701	$17,580	$546	$557	$568	$580	$591	$603	$615	$627	$640	$653	$666	$679	$693	$707	$721	$735	$750	$765	$780	$796	$812	$828	$844	$861	$878
$24,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$141,474	$238,204	$5,881	$5,999	$6,119	$6,241	$6,366	$6,493	$6,623	$6,756	$6,891	$7,029	$7,169	$7,313	$7,459	$7,608	$7,760	$7,915	$8,074	$8,235	$8,400	$8,568	$8,739	$8,914	$9,092	$9,274	$9,460
$70,737	$119,102	$2,941	$2,999	$3,059	$3,121	$3,183	$3,247	$3,312	$3,378	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,626,954	$2,739,342	$67,635	$68,988	$70,367	$71,775	$73,210	$74,675	$76,168	$77,691	$75,800	$77,316	$78,862	$80,439	$82,048	$83,689	$85,363	$87,070	$88,812	$90,588	$92,399	$94,247	$96,132	$98,055	$100,016	$102,016	$104,057
$192,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$42,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$23,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$11,700	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$269,100	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,896,054	$2,794,129	$67,635	$68,988	$70,367	$71,775	$73,210	$74,675	$76,168	$77,691	$75,800	$77,316	$78,862	$80,439	$82,048	$83,689	$85,363	$87,070	$88,812	$90,588	$92,399	$94,247	$96,132	$98,055	$100,016	$102,016	$104,057
$0	$2,847	$5,807	$5,923	$6,042	$6,163	$6,286	$6,412	$6,540	$6,671	$6,804	$6,940	$7,079	$7,221	$7,365	$7,512	$7,663	$7,816	$7,972	$8,132	$8,294	$8,460	$8,629	$8,802	$8,978	$9,158	$9,341
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$839	$1,711	$1,746	$1,781	$1,816	$1,853	$1,890	$1,927	$1,966	$2,005	$2,045	$2,086	$2,128	$2,171	$2,214	$2,258	$2,303	$2,349	$2,396	$2,444	$2,493	$2,543	$2,594	$2,646	$2,699	$2,753
$0	$612	$1,249	$1,274	$1,300	$1,326	$1,352	$1,379	$1,407	$1,435	$1,464	$1,493	$1,523	$1,553	$1,584	$1,616	$1,649	$1,681	$1,715	$1,749	$1,784	$1,820	$1,856	$1,894	$1,931	$1,970	$2,010
$0	$4,446	$9,071	$9,252	$9,437	$9,626	$9,818	$10,015	$10,215	$10,419	$10,628	$10,840	$11,057	$11,278	$11,504	$11,734	$11,969	$12,208	$12,452	$12,701	$12,955	$13,214	$13,479	$13,748	$14,023	$14,304	$14,590
$0	$10,151	$20,709	$21,123	$21,545	$21,976	$22,416	$22,864	$23,321	$23,788	$24,264	$24,749	$25,244	$25,749	$26,264	$26,789	$27,325	$27,871	$28,429	$28,997	$29,577	$30,169	$30,772	$31,387	$32,015	$32,656	$33,309
$0	$210	$428	$436	$445	$454	$463	$472	$482	$491	$501	$511	$522	$532	$543	$553	$565	$576	$587	$599	$611	$623	$636	$649	$661	$675	$688
$0	$4,594	$9,371	$9,558	$9,750	$9,945	$10,143	$10,346	$10,553	$10,764	$10,980	$11,199	$11,423	$11,652	$11,885	$12,122	$12,365	$12,612	$12,864	$13,122	$13,384	$13,652	$13,925	$14,203	$14,487	$14,777	$15,073
$0	$1,594	$3,252	$3,317	$3,383	$3,451	$3,520	$3,590	$3,662	$3,735	$3,810	$3,886	$3,964	$4,043	$4,124	$4,207	$4,291	$4,376	$4,464	$4,553	$4,644	$4,737	$4,832	$4,929	$5,027	$5,128	$5,230
$689,400	$629,748	$79,903	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$2,585,454	$3,449,170	$199,136	$121,618	$124,050	$126,531	$129,062	$131,643	$134,276	$136,961	$136,255	$138,980	$141,760	$144,595	$147,487	$150,437	$153,446	$156,514	$159,645	$162,838	$166,094	$169,416	$172,805	$176,261	$179,786	$183,382	$187,049

Assumptions: Yukon Electrical AMR Project with 20% increase to Capital
Conventional Meter Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.0325
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.0405
TOTALS			9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **8.09%**

D Escalation Rate **2.0%**

E US Exchange Rate **1**

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Incremental Capital Cost:

Input Starting Construction Year: **Jan-14**

	Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40	Year 27 Jan-41	Year 28 Jan-42
# of Residential Meters to be installed/replaced		1,850	1,850	1,850	1,850	1,850	1,850	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
# of Commercial Meters to be installed/replaced		150	150	150	150	150	150	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
1 Cost of Residential Meter	$35.00 /meter	$64,750	$64,750	$64,750	$64,750	$64,750	$64,750	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000
2 Cost of Commercial Meter	#########	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
3 Installation - Residential Meters	$19.80 /meter	$36,630	$36,630	$36,630	$36,630	$36,630	$36,630	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920	$7,920
4 Installation - Commerical Meters	$55.00 /meter	$8,250	$8,250	$8,250	$8,250	$8,250	$8,250	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750
5 Freight Cost (in CDN)	$10.00 /meter	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500
6 Residential Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Commerical Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Retrofitting Costs	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Meter Read Verification	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$159,630	$159,630	$159,630	$159,630	$159,630	$159,630	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170	$39,170
TOTAL Capital		**$159,630**	**$159,630**	**$159,630**	**$159,630**	**$159,630**	**$159,630**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**	**$39,170**

I **Conventional O&M Costs:**

1 Manual Meter Reading Costs		$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800
2 Meter Test Costs	$36.40 /meter	$72,800	$72,800	$72,800	$72,800	$72,800	$72,800	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380
3 Customer Applications & Service Orders		$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000
4 Data Cap Costs		$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8																														
9																														
TOTAL O&M		**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,982**	**$632,984**
Total Cash Flow		**$849,030**	**$849,030**	**$849,030**	**$849,030**	**$849,030**	**$849,030**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,150**	**$672,152**	**$672,154**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41	Jan-42
$64,750	$66,045	$67,366	$68,713	$70,087	$71,489	$15,766	$16,082	$16,403	$16,731	$17,066	$17,407	$17,755	$18,110	$18,473	$18,842	$19,219	$19,603	$19,995	$20,395	$20,803	$21,219	$21,644	$22,077	$22,518	$22,968	$23,428	$23,896	$24,374
$30,000	$30,600	$31,212	$31,836	$32,473	$33,122	$11,262	$11,487	$11,717	$11,951	$12,190	$12,434	$12,682	$12,936	$13,195	$13,459	$13,728	$14,002	$14,282	$14,568	$14,859	$15,157	$15,460	$15,769	$16,084	$16,406	$16,734	$17,069	$17,410
$36,630	$37,363	$38,110	$38,872	$39,649	$40,442	$8,919	$9,098	$9,280	$9,465	$9,654	$9,848	$10,044	$10,245	$10,450	$10,659	$10,872	$11,090	$11,312	$11,538	$11,769	$12,004	$12,244	$12,489	$12,739	$12,994	$13,253	$13,519	$13,789
$8,250	$8,415	$8,583	$8,755	$8,930	$9,109	$3,097	$3,159	$3,222	$3,287	$3,352	$3,419	$3,488	$3,557	$3,629	$3,701	$3,775	$3,851	$3,928	$4,006	$4,086	$4,168	$4,251	$4,336	$4,423	$4,512	$4,602	$4,694	$4,788
$20,000	$20,400	$20,808	$21,224	$21,649	$22,082	$5,068	$5,169	$5,272	$5,378	$5,485	$5,595	$5,707	$5,821	$5,938	$6,056	$6,178	$6,301	$6,427	$6,556	$6,687	$6,820	$6,957	$7,096	$7,238	$7,383	$7,530	$7,681	$7,835
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$159,630	$162,823	$166,079	$169,401	$172,789	$176,244	$44,112	$44,994	$45,894	$46,812	$47,748	$48,703	$49,677	$50,671	$51,684	$52,718	$53,772	$54,847	$55,944	$57,063	$58,205	$59,369	$60,556	$61,767	$63,002	$64,263	$65,548	$66,859	$68,196
$159,630	$162,823	$166,079	$169,401	$172,789	$176,244	$44,112	$44,994	$45,894	$46,812	$47,748	$48,703	$49,677	$50,671	$51,684	$52,718	$53,772	$54,847	$55,944	$57,063	$58,205	$59,369	$60,556	$61,767	$63,002	$64,263	$65,548	$66,859	$68,196
$460,800	$470,016	$479,416	$489,005	$498,785	$508,760	$518,936	$529,314	$539,901	$550,699	$561,713	$572,947	$584,406	$596,094	$608,016	$620,176	$632,580	$645,231	$658,136	$671,299	$684,725	$698,419	$712,387	$726,635	$741,168	$755,991	$771,111	$786,533	$802,264
$72,800	$74,256	$75,741	$77,256	$78,801	$80,377	$18,447	$18,815	$19,192	$19,576	$19,967	$20,366	$20,774	$21,189	$21,613	$22,045	$22,486	$22,936	$23,395	$23,863	$24,340	$24,827	$25,323	$25,830	$26,346	$26,873	$27,411	$27,959	$28,518
$135,000	$137,700	$140,454	$143,263	$146,128	$149,051	$152,032	$155,073	$158,174	$161,337	$164,564	$167,856	$171,213	$174,637	$178,130	$181,692	$185,326	$189,033	$192,813	$196,670	$200,603	$204,615	$208,707	$212,881	$217,139	$221,482	$225,911	$230,430	$235,038
$20,800	$21,216	$21,640	$22,073	$22,515	$22,965	$23,424	$23,893	$24,371	$24,858	$25,355	$25,862	$26,379	$26,907	$27,445	$27,994	$28,554	$29,125	$29,708	$30,302	$30,908	$31,526	$32,156	$32,800	$33,455	$34,125	$34,807	$35,503	$36,213
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$703,188	$717,252	$731,597	$746,229	$761,153	$712,838	$727,095	$741,637	$756,470	$771,599	$787,031	$802,772	$818,827	$835,204	$851,908	$868,946	$886,325	$904,051	$922,132	$940,575	$959,386	$978,574	$998,146	$1,018,109	#######	$1,059,240	$1,080,428	$1,102,040
$849,030	$866,011	$883,331	$900,997	$919,017	$937,398	$756,950	$772,089	$787,531	$803,281	$819,347	$835,734	$852,449	$869,498	$886,888	$904,625	$922,718	$941,172	$959,996	$979,196	$998,780	#######	$1,039,130	#######	$1,081,111	#######	$1,124,788	$1,147,287	$1,170,236

Yukon Electrical AMR Project with 20% increase to Capital

AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
1 Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Cost of Residential AMR Module	437,667	890,307	452,640	15,747	16,062	16,383	16,711	17,045	17,386	17,733	18,088	18,450	18,819	19,195	19,579	19,971	20,370	20,777	21,193	21,617	22,049	22,490	22,940	23,399	23,867	24,344	24,831	25,328
3 Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Cost of Commercial AMR Module	0	421,593	421,593	6,579	6,711	6,845	6,982	7,122	7,264	7,409	7,558	7,709	7,863	8,020	8,181	8,344	8,511	8,681	8,855	9,032	9,213	9,397	9,585	9,777	9,972	10,172	10,375	10,583
5 Installation - Residential Meters	62,796	127,740	64,944	2,259	2,304	2,351	2,398	2,446	2,494	2,544	2,595	2,647	2,700	2,754	2,809	2,865	2,923	2,981	3,041	3,102	3,164	3,227	3,291	3,357	3,424	3,493	3,563	3,634
6 Installation - Commerical Meters	0	194,217	194,217	3,031	3,092	3,153	3,216	3,281	3,346	3,413	3,482	3,551	3,622	3,695	3,769	3,844	3,921	3,999	4,079	4,161	4,244	4,329	4,416	4,504	4,594	4,686	4,780	4,875
7 Freight	38,058	86,892	48,834	1,517	1,547	1,578	1,610	1,642	1,675	1,709	1,743	1,778	1,813	1,849	1,886	1,924	1,963	2,002	2,042	2,083	2,124	2,167	2,210	2,254	2,299	2,345	2,392	2,440
8 Billing System Configuration	150,000	150,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Meter Read Verification	6,850	15,641	8,790	273	279	284	290	296	302	308	314	320	326	333	340	346	353	360	368	375	382	390	398	406	414	422	431	439
12 Test Set & Spares Equipment	12,000	12,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Contingency	70,737	189,839	119,102	2,941	2,999	3,059	3,121	3,183	3,247	3,312	3,378	3,445	3,514	3,585	3,656	3,729	3,804	3,880	3,958	4,037	4,118	4,200	4,284	4,370	4,457	4,546	4,637	4,730
14 Project Management	35,369	94,919	59,551	1,470	1,500	1,530	1,560	1,592	1,623	1,656	1,689	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials	96,000	96,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Installation by YECL	21,000	21,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Contingency	11,700	11,700	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Project Management	5,850	5,850	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	948,027	2,317,698	1,369,671	33,818	34,494	35,184	35,887	36,605	37,337	38,084	38,846	37,900	38,658	39,431	40,220	41,024	41,845	42,681	43,535	44,406	45,294	46,200	47,124	48,066	49,028	50,008	51,008	52,028

Operations & Maintenance:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Allocated AMR O&M Costs:																												
19 O&M Acct#71212 - DCSI TNS Maintenanc	0	2,847	5,807	5,923	6,042	6,163	6,286	6,412	6,540	6,671	6,804	6,940	7,079	7,221	7,365	7,512	7,663	7,816	7,972	8,132	8,294	8,460	8,629	8,802	8,978	9,158	0	0
20 O&M Acct#71214 - Annual Sample Verifica	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 O&M Acct#72107 - I-Tek User Fees (Emai	0	839	1,711	1,746	1,781	1,816	1,853	1,890	1,927	1,966	2,005	2,045	2,086	2,128	2,171	2,214	2,258	2,303	2,349	2,396	2,444	2,493	2,543	2,594	2,646	2,699	0	0
22 O&M Acct#72109 - PCs & Monitors	0	612	1,249	1,274	1,300	1,326	1,352	1,379	1,407	1,435	1,464	1,493	1,523	1,553	1,584	1,616	1,649	1,681	1,715	1,749	1,784	1,820	1,856	1,894	1,931	1,970	0	0
23 O&M Acct#72118 - I-Tek Support for TNS	0	4,446	9,071	9,252	9,437	9,626	9,818	10,015	10,215	10,419	10,628	10,840	11,057	11,278	11,504	11,734	11,969	12,208	12,452	12,701	12,955	13,214	13,479	13,748	14,023	14,304	0	0
24 Labour Acct#71211 - AMR Meter Reading	0	10,151	20,709	21,123	21,545	21,976	22,416	22,864	23,321	23,788	24,264	24,749	25,244	25,749	26,264	26,789	27,325	27,871	28,429	28,997	29,577	30,169	30,772	31,387	32,015	32,656	0	0
25 Labour Acct#71214 - AMR Verification	0	210	428	436	445	454	463	472	482	491	501	511	522	532	543	553	565	576	587	599	611	623	636	649	661	675	0	0
26 Labour Acct#71215 - AMR Substation Trou	0	4,594	9,371	9,558	9,750	9,945	10,143	10,346	10,553	10,764	10,980	11,199	11,423	11,652	11,885	12,122	12,365	12,612	12,864	13,122	13,384	13,652	13,925	14,203	14,487	14,777	0	0
27 Labour Acct# 71250 - AMR Special Meter I	0	1,594	3,252	3,317	3,383	3,451	3,520	3,590	3,662	3,735	3,810	3,886	3,964	4,043	4,124	4,207	4,291	4,376	4,464	4,553	4,644	4,737	4,832	4,929	5,027	5,128	0	0
28 Conventional Meter Read Costs	689,400	629,748	79,903	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Affiliate Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AMR O&M Savings / Revenue:																												
29 Project Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Data-Cap Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Reduced Read-to-Bill Lag	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Manual Meter Reading Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	689,400	655,041	131,501	52,630	53,683	54,756	55,852	56,969	58,108	59,270	60,455	61,665	62,898	64,156	65,439	66,748	68,083	69,444	70,833	72,250	73,695	75,169	76,672	78,206	79,770	81,365	0	0

Yukon Electrical AMR Project with 20% increase to Capital

AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
Cost of Residential Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	7.130%	31,206	94,685	126,958	128,081	129,226	130,394	131,585	132,801	134,040	135,305	136,594	137,910	139,251	140,620	142,016	142,534	20,398	20,806	21,223	21,647	22,080	22,522	22,972	23,431	23,900	24,378	24,866
Cost of Commercial Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	7.130%	0	30,060	60,119	60,588	61,067	61,555	62,053	62,560	63,078	63,607	64,146	64,695	65,256	65,828	66,411	67,006	30,864	8,693	8,867	9,045	9,226	9,410	9,598	9,790	9,986	10,186	10,390
Installation - Residential Meters	7.130%	4,477	13,585	18,216	18,377	18,541	18,709	18,880	19,054	19,232	19,413	19,598	19,787	19,980	20,176	20,376	20,451	2,927	2,985	3,045	3,106	3,168	3,231	3,296	3,362	3,429	3,498	3,568
Installation - Commerical Meters	7.130%	0	13,848	27,695	27,911	28,132	28,357	28,586	28,820	29,059	29,302	29,550	29,803	30,062	30,325	30,594	30,868	14,218	4,005	4,085	4,167	4,250	4,335	4,422	4,510	4,600	4,692	4,786
Freight	7.130%	2,714	8,909	12,391	12,499	12,609	12,722	12,837	12,954	13,073	13,195	13,319	13,446	13,575	13,707	13,842	13,979	2,389	2,005	2,045	2,086	2,127	2,170	2,213	2,258	2,303	2,349	2,396
Billing System Configuration	7.130%	10,695	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	21,390	11,235	0	0	0	0	0	0	0	0	0	0	0	0
0	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	7.130%	488	1,604	2,230	2,250	2,270	2,290	2,311	2,332	2,353	2,375	2,397	2,420	2,444	2,467	2,491	2,516	430	361	368	375	383	391	398	406	414	423	431
Test Set & Spares Equipment	7.130%	856	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	899	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	5,044	18,579	27,071	27,281	27,495	27,713	27,935	28,162	28,394	28,630	28,871	29,116	29,367	29,622	29,883	29,952	3,809	3,886	3,963	4,043	4,123	4,206	4,290	4,376	4,463	4,553	4,644
Project Management	7.130%	2,522	9,290	13,536	13,640	13,747	13,856	13,968	14,081	14,197	14,315	14,435	14,435	14,435	14,435	14,435	7,131	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:																												
Aclara SCE materials	7.130%	6,845	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	13,690	7,190	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	7.130%	1,497	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	2,995	1,573	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	834	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	876	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	7.130%	417	834	834	834	834	834	834	834	834	834	834	834	834	834	438	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		67,594	232,846	330,504	332,915	335,374	337,883	340,442	343,052	345,714	348,429	351,199	353,901	356,657	359,469	342,260	314,436	75,035	42,741	43,596	44,468	45,357	46,264	47,190	48,133	49,096	50,078	51,080

ACCUMULATED DEPRECIATION:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	31,206	125,890	252,848	380,928	510,154	640,548	772,133	904,934	1,038,974	1,174,279	1,310,873	1,448,782	1,588,034	1,728,654	1,870,670	2,013,204	2,033,603	2,054,409	2,075,632	2,097,279	2,119,359	2,141,880	2,164,852	2,188,284	2,212,184	2,236,562	2,261,428
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	30,060	90,179	150,767	211,834	273,389	335,441	398,002	461,080	524,687	588,832	653,527	718,783	784,611	851,022	918,028	948,891	957,585	966,452	975,497	984,723	994,133	1,003,731	1,013,521	1,023,507	1,033,693	1,044,083
Installation - Residential Meters	0	4,477	18,063	36,278	54,655	73,196	91,905	110,784	129,838	149,070	168,483	188,082	207,869	227,848	248,024	268,400	288,851	291,778	294,763	297,808	300,914	304,082	307,313	310,609	313,971	317,400	320,898	324,466
Installation - Commerical Meters	0	0	13,848	41,543	69,454	97,586	125,943	154,529	183,349	212,408	241,710	271,260	301,063	331,125	361,450	392,044	422,912	437,130	441,135	445,220	449,386	453,636	457,971	462,393	466,903	471,503	476,196	480,982
Freight	0	2,714	11,622	24,013	36,512	49,122	61,843	74,680	87,634	100,707	113,902	127,221	140,667	154,242	167,949	181,791	195,770	198,158	200,163	202,208	204,293	206,421	208,590	210,804	213,061	215,364	217,713	220,108
Billing System Configuration	0	10,695	32,085	53,475	74,865	96,255	117,645	139,035	160,425	181,815	203,205	224,595	245,985	267,375	288,765	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	488	2,092	4,322	6,572	8,842	11,132	13,442	15,774	18,127	20,502	22,900	25,320	27,764	30,231	32,722	35,239	35,668	36,029	36,397	36,773	37,156	37,546	37,945	38,351	38,765	39,188	39,619
Test Set & Spares Equipment	0	856	2,567	4,278	5,989	7,700	9,412	11,123	12,834	14,545	16,256	17,968	19,679	21,390	23,101	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000	24,000
Contingency	0	5,044	23,623	50,694	77,974	105,469	133,182	161,117	189,279	217,673	246,302	275,173	304,289	333,656	363,279	393,162	423,113	426,923	430,808	434,772	438,814	442,938	447,143	451,433	455,809	460,272	464,825	469,469
Project Management	0	2,522	11,811	25,347	38,987	52,734	66,591	80,558	94,639	108,836	123,151	137,586	152,022	166,457	180,892	195,328	202,459	202,459	202,459	202,459	202,459	202,459	202,459	202,459	202,459	202,459	202,459	202,459
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	6,845	20,534	34,224	47,914	61,603	75,293	88,982	102,672	116,362	130,051	143,741	157,430	171,120	184,810	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000	192,000
Installation by YECL	0	1,497	4,492	7,487	10,481	13,476	16,470	19,465	22,460	25,454	28,449	31,443	34,438	37,433	40,427	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000
Contingency	0	834	2,503	4,171	5,839	7,508	9,176	10,845	12,513	14,182	15,850	17,518	19,187	20,855	22,524	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400	23,400
Project Management	0	417	1,251	2,086	2,920	3,754	4,588	5,422	6,257	7,091	7,925	8,759	9,593	10,428	11,262	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
		67,594	300,440	630,944	963,859	1,299,233	1,637,116	1,977,558	2,320,609	2,666,323	3,014,752	3,365,951	3,719,852	4,076,510	4,435,979	4,778,238	5,092,674	5,167,709	5,210,451	5,254,046	5,298,514	5,343,872	5,390,136	5,437,325	5,485,459	5,534,555	5,584,633	5,635,713

PROPERTY IN SERVICE (beg yr):	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	437,667	1,296,768	1,654,724	1,543,513	1,431,494	1,318,651	1,204,968	1,090,427	975,012	858,705	741,489	623,344	504,253	384,197	263,156	141,111	18,946	19,325	19,712	20,106	20,508	20,918	21,336	21,763	22,198	22,642	23,095
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	421,593	813,126	759,587	705,709	651,488	596,915	541,984	486,688	431,019	374,970	318,533	261,701	204,465	146,818	88,752	30,257	8,075	8,236	8,401	8,569	8,740	8,915	9,093	9,275	9,461	9,650
Installation - Residential Meters	0	62,796	186,058	237,417	221,461	205,388	189,198	172,887	156,453	139,893	123,206	106,388	89,436	72,349	55,124	37,757	20,246	2,718	2,773	2,828	2,885	2,943	3,001	3,061	3,123	3,185	3,249	3,314
Installation - Commerical Meters	0	0	194,217	374,586	349,922	325,102	300,124	274,983	249,678	224,205	198,559	172,739	146,740	120,559	94,192	67,635	40,886	13,939	3,720	3,794	3,870	3,947	4,026	4,107	4,189	4,273	4,358	4,445
Freight	0	38,058	122,236	162,162	151,288	140,336	129,305	118,194	106,999	95,720	84,356	72,904	61,362	49,729	38,003	26,182	14,265	2,249	1,862	1,899	1,937	1,976	2,015	2,056	2,097	2,139	2,182	2,225
Billing System Configuration	0	150,000	289,305	267,915	246,525	225,135	203,745	182,355	160,965	139,575	118,185	96,795	75,405	54,015	32,625	11,235	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	6,850	22,003	29,189	27,232	25,261	23,275	21,275	19,260	17,230	15,184	13,123	11,045	8,951	6,841	4,713	2,568	405	335	342	349	356	363	370	377	385	393	401
Test Set & Spares Equipment	0	12,000	23,144	21,433	19,722	18,011	16,300	14,588	12,877	11,166	9,455	7,744	6,032	4,321	2,610	899	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	70,737	255,532	356,055	331,925	307,644	283,209	258,616	233,864	208,949	183,867	158,615	133,190	107,588	81,806	55,840	29,686	3,538	3,609	3,681	3,755	3,830	3,906	3,985	4,064	4,146	4,228	4,313
Project Management	0	35,369	127,766	178,028	165,962	153,822	141,604	129,308	116,932	104,474	91,933	79,307	64,872	50,437	36,002	21,566	7,131	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	96,000	185,155	171,466	157,776	144,086	130,397	116,707	103,018	89,328	75,638	61,949	48,259	34,570	20,880	7,190	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	0	21,000	40,503	37,508	34,514	31,519	28,524	25,530	22,535	19,541	16,546	13,551	10,557	7,562	4,568	1,573	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	11,700	22,566	20,897	19,229	17,561	15,892	14,224	12,555	10,887	9,218	7,550	5,882	4,213	2,545	876	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	0	5,850	11,283	10,449	9,614	8,780	7,946	7,112	6,278	5,443	4,609	3,775	2,941	2,107	1,272	438	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	948,027	3,198,130	4,334,955	4,038,269	3,739,848	3,439,657	3,137,662	2,833,825	2,528,111	2,220,481	1,910,898	1,597,599	1,282,355	965,129	645,880	344,644	72,052	39,699	40,493	41,303	42,129	42,971	43,831	44,707	45,601	46,513	47,444

Yukon Electrical AMR Project with 20 % incre
AMR Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	30.000%		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037 %	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	689,400	689,400	0	(689,400)	(689,400)	0
1	Jan-15	948,027	69,210	67,594	16,465	655,041	808,310	0	(808,310)	(1,430,716)	1
2	Jan-16	3,198,130	233,476	232,846	55,543	131,501	653,367	0	(653,367)	(1,980,267)	2
3	Jan-17	4,334,955	316,469	330,504	75,287	52,630	774,890	0	(774,890)	(2,578,013)	3
4	Jan-18	4,038,269	294,810	332,915	70,134	53,683	751,542	0	(751,542)	(3,109,699)	4
5	Jan-19	3,739,848	273,024	335,374	64,952	54,756	728,106	0	(728,106)	(3,582,113)	5
6	Jan-20	3,439,657	251,109	337,883	59,738	55,852	704,581	0	(704,581)	(4,001,374)	6
7	Jan-21	3,137,662	229,062	340,442	54,493	56,969	680,965	0	(680,965)	(4,372,997)	7
8	Jan-22	2,833,825	206,881	343,052	49,216	58,108	657,256	0	(657,256)	(4,701,954)	8
9	Jan-23	2,528,111	184,562	345,714	43,907	59,270	633,453	0	(633,453)	(4,992,721)	9
10	Jan-24	2,220,481	162,104	348,429	38,564	60,455	609,553	0	(609,553)	(5,249,327)	10
11	Jan-25	1,910,898	139,503	351,199	33,187	61,665	585,554	0	(585,554)	(5,475,399)	11
12	Jan-26	1,597,599	116,631	353,901	27,746	62,898	561,176	0	(561,176)	(5,674,103)	12
13	Jan-27	1,282,355	93,617	356,657	22,271	64,156	536,702	0	(536,702)	(5,848,390)	13
14	Jan-28	965,129	70,458	359,469	16,762	65,439	512,128	0	(512,128)	(6,000,913)	14
15	Jan-29	645,880	47,152	342,260	11,217	66,748	467,376	0	(467,376)	(6,128,572)	15
16	Jan-30	344,644	25,160	314,436	5,986	68,083	413,665	0	(413,665)	(6,232,195)	16
17	Jan-31	72,052	5,260	75,035	1,251	69,444	150,991	0	(150,991)	(6,266,883)	17
18	Jan-32	39,699	2,898	42,741	689	70,833	117,162	0	(117,162)	(6,291,569)	18
19	Jan-33	40,493	2,956	43,596	703	72,250	119,505	0	(119,505)	(6,314,662)	19
20	Jan-34	41,303	3,015	44,468	717	73,695	121,895	0	(121,895)	(6,336,264)	20
21	Jan-35	42,129	3,076	45,357	732	75,169	124,333	0	(124,333)	(6,356,472)	21
22	Jan-36	42,971	3,137	46,264	746	76,672	126,820	0	(126,820)	(6,375,376)	22
23	Jan-37	43,831	3,200	47,190	761	78,206	129,356	0	(129,356)	(6,393,059)	23
24	Jan-38	44,707	3,264	48,133	776	79,770	131,943	0	(131,943)	(6,409,602)	24
25	Jan-39	45,601	3,329	49,096	792	81,365	134,582	0	(134,582)	(6,425,077)	25
26	Jan-40	46,513	3,396	50,078	808	0	54,281	0	(54,281)	(6,430,801)	26
27	Jan-41	47,444	3,464	51,080	824	0	55,367	0	(55,367)	(6,436,156)	27
28	Jan-42	48,393	3,533	52,101	840	0	56,474	0	(56,474)	(6,441,165)	28
29	Jan-43	(3,709)	(271)	(3,710)	(64)	0	(4,045)	0	4,045	(6,440,836)	29
30	Jan-44	1	0	0	0	0	0	0	(0)	(6,440,836)	30
31	Jan-45	1	0	0	0	0	0	0	(0)	(6,440,836)	31
32	Jan-46	1	0	0	0	0	0	0	(0)	(6,440,836)	32
33	Jan-47	1	0	0	0	0	0	0	(0)	(6,440,836)	33
34	Jan-48	1	0	0	0	0	0	0	(0)	(6,440,836)	34
35	Jan-49	1	0	0	0	0	0	0	(0)	(6,440,836)	35
36	Jan-50	1	0	0	0	0	0	0	(0)	(6,440,836)	36
37	Jan-51	1	0	0	0	0	0	0	(0)	(6,440,836)	37
38	Jan-52	1	0	0	0	0	0	0	(0)	(6,440,836)	38
39	Jan-53	1	0	0	0	0	0	0	(0)	(6,440,836)	39
40	Jan-54	1	0	0	0	0	0	0	(0)	(6,440,836)	40

Yukon Electrical AMR Project with 20% increase to Capital
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

O&M:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Manual Meter Reading Costs	0	470,016	479,416	489,005	498,785	508,760	518,936	529,314	539,901	550,699	561,713	572,947	584,406	596,094	608,016	620,176	632,580	645,231	658,136	671,299	684,725	698,419	712,387	726,635	741,168	755,991	771,111	786,533
Meter Test Costs	0	74,256	75,741	77,256	78,801	80,377	18,447	18,815	19,192	19,576	19,967	20,366	20,774	21,189	21,613	22,045	22,486	22,936	23,395	23,863	24,340	24,827	25,323	25,830	26,346	26,873	27,411	27,959
Customer Applications & Service Or	0	137,700	140,454	143,263	146,128	149,051	152,032	155,073	158,174	161,337	164,564	167,856	171,213	174,637	178,130	181,692	185,326	189,033	192,813	196,670	200,603	204,615	208,707	212,881	217,139	221,482	225,911	230,430
Data Cap Costs	0	21,216	21,640	22,073	22,515	22,965	23,424	23,893	24,371	24,858	25,355	25,862	26,379	26,907	27,445	27,994	28,554	29,125	29,708	30,302	30,908	31,526	32,156	32,800	33,455	34,125	34,807	35,503
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	0	703,188	717,252	731,597	746,229	761,153	712,838	727,095	741,637	756,470	771,599	787,031	802,772	818,827	835,204	851,908	868,946	886,325	904,051	922,132	940,575	959,386	978,574	998,146	1,018,109	1,038,471	1,059,240	1,080,425

Yukon Electrical AMR Project with 20% increase to Capital
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	8.090%	2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0

ACCUMULATED DEPRECIATION	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	2,619	10,529	23,890	42,865	61,840	80,815	99,791	118,766	137,741	156,716	175,692	194,667	213,642	232,617	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PROPERTY IN SERVICE (beg yr	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0

Yukon Electrical AMR Project with 20%
Conventional Meter Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	#####		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	0	0	0	0	0	0
1	Jan-15	32,375	2,364	2,619	562	703,188	708,733	0	(708,733)	(649,992)	1
2	Jan-16	95,153	6,947	7,910	1,653	717,252	733,761	0	(733,761)	(1,267,163)	2
3	Jan-17	154,623	11,288	13,361	2,685	731,597	758,931	0	(758,931)	(1,852,599)	3
4	Jan-18	210,662	15,379	18,975	3,659	746,229	784,242	0	(784,242)	(2,407,419)	4
5	Jan-19	191,687	13,994	18,975	3,329	761,153	797,452	0	(797,452)	(2,924,825)	5
6	Jan-20	172,712	12,609	18,975	3,000	712,838	747,422	0	(747,422)	(3,369,578)	6
7	Jan-21	153,737	11,223	18,975	2,670	727,095	759,964	0	(759,964)	(3,784,314)	7
8	Jan-22	134,761	9,838	18,975	2,340	741,637	772,791	0	(772,791)	(4,171,096)	8
9	Jan-23	115,786	8,453	18,975	2,011	756,470	785,909	0	(785,909)	(4,531,842)	9
10	Jan-24	96,811	7,068	18,975	1,681	771,599	799,323	0	(799,323)	(4,868,337)	10
11	Jan-25	77,835	5,682	18,975	1,352	787,031	813,040	0	(813,040)	(5,182,238)	11
12	Jan-26	58,860	4,297	18,975	1,022	802,772	827,066	0	(827,066)	(5,475,089)	12
13	Jan-27	39,885	2,912	18,975	693	818,827	841,407	0	(841,407)	(5,748,325)	13
14	Jan-28	20,910	1,526	18,975	363	835,204	856,069	0	(856,069)	(6,003,282)	14
15	Jan-29	1,934	141	1,934	34	851,908	854,017	0	(854,017)	(6,236,547)	15
16	Jan-30	0	0	0	0	868,946	868,946	0	(868,946)	(6,454,218)	16
17	Jan-31	0	0	0	0	886,325	886,325	0	(886,325)	(6,657,841)	17
18	Jan-32	0	0	0	0	904,051	904,051	0	(904,051)	(6,848,323)	18
19	Jan-33	0	0	0	0	922,132	922,132	0	(922,132)	(7,026,511)	19
20	Jan-34	0	0	0	0	940,575	940,575	0	(940,575)	(7,193,199)	20
21	Jan-35	0	0	0	0	959,386	959,386	0	(959,386)	(7,349,129)	21
22	Jan-36	0	0	0	0	978,574	978,574	0	(978,574)	(7,494,995)	22
23	Jan-37	0	0	0	0	998,146	998,146	0	(998,146)	(7,631,448)	23
24	Jan-38	0	0	0	0	1,018,109	1,018,109	0	(1,018,109)	(7,759,094)	24
25	Jan-39	0	0	0	0	1,038,471	1,038,471	0	(1,038,471)	(7,878,501)	25
26	Jan-40	0	0	0	0	1,059,240	1,059,240	0	(1,059,240)	(7,990,203)	26
27	Jan-41	0	0	0	0	1,080,425	1,080,425	0	(1,080,425)	(8,094,695)	27
28	Jan-42	0	0	0	0	1,102,034	1,102,034	0	(1,102,034)	(8,192,443)	28
29	Jan-43	0	0	0	0	0	0	0	(0)	(8,192,443)	29
30	Jan-44	0	0	0	0	0	0	0	(0)	(8,192,443)	30
31	Jan-45	0	0	0	0	0	0	0	(0)	(8,192,443)	31
32	Jan-46	0	0	0	0	0	0	0	(0)	(8,192,443)	32
33	Jan-47	0	0	0	0	0	0	0	(0)	(8,192,443)	33
34	Jan-48	0	0	0	0	0	0	0	(0)	(8,192,443)	34
35	Jan-49	0	0	0	0	0	0	0	(0)	(8,192,443)	35
36	Jan-50	0	0	0	0	0	0	0	(0)	(8,192,443)	36
37	Jan-51	0	0	0	0	0	0	0	(0)	(8,192,443)	37
38	Jan-52	0	0	0	0	0	0	0	(0)	(8,192,443)	38
39	Jan-53	0	0	0	0	0	0	0	(0)	(8,192,443)	39
40	Jan-54	0	0	0	0	0	0	0	(0)	(8,192,443)	40

CW-YECL-26

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 29

In Business Case 29, YECL proposes upgrades to the downtown office building envelope. YECL asserts the changes will improve energy efficiency. The City requires information to assess this claim.

Request:

(a) Please provide actual operating costs of the downtown office for 2008, 2009, 2010, 2011, and 2012. Please separate out heating, lighting, water and sewer, and other operating costs.

(b) Please provide YECL's forecast of the costs identified in response to (a) above for 2013, 2014, and 2015.

(c) Please provide an analysis that clearly demonstrates how the forecast cost reductions have been incorporated into this GRA.

Response:

(a) Please refer to CW-YECL-26(a) Attachment 1.

Please note that all costs, with the exception of heating, relate to both the downtown office and service complex as they not tracked separately for each location.

(b) Yukon Electrical based its forecast of the operating costs for both facilities on the historical 3-year average, less the forecast cost reduction related to improved energy efficiency as a result of upgrades to the downtown office building. Yukon Electrical's forecast savings on billed energy for the office complex are $1,500 per year based on the 2010 to 2012 period.

(c) Please refer to CW-YECL-26(c) Attachment 1.

The Yukon Electrical Company Limited
Operating Costs For Downtown Office and Whitehorse Service Complex

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Heating - Service Complex	16	15	16	18	17
Heating - Downtown Office	10	5	6	10	8
Lighting and Electric Heating/Air Conditioning *	-	-	-	-	-
Water and Sewer	4	3	3	5	4
Repairs & Maintenance	24	35	36	30	54
Janitorial and Cleaning Costs	33	33	35	29	32
Waste Removal & Recycling	4	4	3	3	4
Snow Removal	6	9	4	4	6
Other	11	9	19	16	22
Schedule 5.3, L. 22	**108**	**112**	**122**	**115**	**147**

* Yukon Electrical does not bill itself for electricity costs. As a result, no costs for electricity are included in account 88900.

The Yukon Electrical Company Limited
Forecast of Operating Costs

	2010 Actual	2011 Actual	2012 Actual	3-Year Average
Schedule 5.3, L. 22	122	115	147	128

	2013 Forecast	2014 Forecast	2015 Forecast
Schedule 5.3, L. 22	129	132	135

CW-YECL-27

Reference: Capital Expenditures – Business Cases, YECL Application, Business Case 30 and Yukon Five Year Demand Side Management Plan

YECL provides a joint Demand Side Management (DSM) report. The City requires information to assess the project.

Request:

(a) On page 24 and 25 of the Yukon Five Year Demand Side Management Plan, the report discusses implementation. There does not appear to be an analysis of the Lifecycle costs of program. Please provide an analysis of the cost of the program over the life of the program, identifying:

(i) Yukon Electrical program delivery costs for each year.

(ii) projected human resource costs related, and costs allocated to YECL for each year.

(iii) projected marketing and communications costs that occur outside of the Demand Side Management Program Portfolio costs, and costs allocated to YECL for each year.

(iv) projected agreed upon pilot projects (LED street lights), and costs allocated to YECL for each year.

(v) Costs beyond the in Charge commitments:

- Internal DSM projects
- Administrative costs
- Staff training and development
- YECL industrial customer DSM programs
- YECL office costs
- Additional staff costs

(vi) Please separate operating and capital costs.

(vii) Please reconcile the costs provided in response to (i) – (iv) above to the costs included in this GRA.

(b) The City is interested in understanding the measurement of results and achievement of goals and benefits. On page 25 of the Yukon Five Year Demand Side Management Plan, it states that program level evaluation, measurement and verification (EM&V) is available in the Joint Utility EM&V Plan (2013). Please indicate if and where this report is included in this application. Specifically please identify where details about EM&V are provided. If the Joint Utility EM&V Plan (2013) is not included in this filing, please provide the report.

(c) Please provide the benefit, in terms of reduced capital or operating costs, of achieving the 8.5 GWh target of the program.

(d) Please fully describe the process for the review and approval of budgets and actual expenditures of the DSM program.

Response:

(a) The joint DSM plan is five years in duration and is not analyzed as a whole on a life cycle basis. Lifecycle analysis was completed for each of the program technologies and was evaluated against the industry standard four cost effectiveness tests. Please refer to the *DSM Program Incentive Justification Levels*, provided in YUB-YECL-27 Attachment 1, for the test evaluations of each technology measure.

(i) Yukon Electrical annual DSM costs are listed in Business Case #30.

2011 - $204,000
2012 - $143,000
2013 - $135,000
2014 - $522,000
2015 - $730,000

(ii) Please refer to the *YECL-DSM Costs 2011-2015* spreadsheet, provided in YUB-YECL-24(b) Attachment 1, for a detailed cost breakdown.

(iii) There are no additional marketing and communication costs related to DSM outside of the program portfolio costs for Yukon Electrical.

(iv) As of the date of this submission the only joint project undertaken is the LED street light pilot study, currently underway with the report expected to be delivered by the end of 2013. The cost to Yukon Electrical related to the LED street light testing project was $2,000 in 2012 and is forecast to be $1,200 in 2013.

(v)

- Internal DSM projects – Yukon Electrical is not applying for any costs related to internal DSM.
- Administrative costs – Yukon Electrical is not applying for any additional costs related to Administrative costs.
- Staff training and development – In 2014, Yukon Electrical is applying for $19,000 for staff training and development as there is currently no internal expertise on DSM. In 2015, Yukon Electrical is applying for $17,000 for staff training and development to provide on-going DSM development for the projected DSM staff.
- Yukon Electrical industrial customer DSM programs – Yukon Electrical is not applying for any DSM costs associated to industrial customers.
- Yukon Electrical office costs – Yukon Electrical is not applying for any additional costs associated with office costs.
- Additional staff costs – Yukon Electrical is applying for additional staff costs of $47,400 in 2013, $91,000 in 2014 and $93,000 in 2015 related to the DSM Coordinator position.

(vi) It is Yukon Electrical's intention to capitalize all costs associated with the DSM program. However, in preparing the responses to Information Requests, it was discovered that some costs had inadvertently been included in both Operations and Maintenance expenses and Capital. These amounts total $88,000 for 2013, $90,000 for 2014 and $92,000

for 2015. This duplication will be rectified by the removal of costs from O&M and this will be corrected and submitted as part of Yukon Electrical's compliance filing.

(vii) There is an immaterial variance in 2012 of $1,800 between the cost breakdown provided in YUB-YECL-24(b) Attachment 1 and the amount included in the Application. For all other years, the costs as per the breakdown agree to the amount as filed.

(b) Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

(c) An analysis of the fuel and O&M costs and the additional diesel capacity (capital) costs with and without a DSM program which saved 8.5 GWh can be seen in figures 4.1 and 4.2, respectively, of the *Yukon Energy 20 Year Resource Plan: 2011-2020*. In the absence of a completed DSM Program, the resource plan examined this scenario for the Base Case in 2015. Fuel and O&M savings for this scenario were estimated at $2.6M and diesel capacity additional savings for this scenario were estimated at $4.7M. The cost of conserved energy of the measures was compared against a $0.21 per kilowatt hour cost which represents a blended avoided cost of supply.

(d) Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL 26(a) Attachment 1, and the *DSM Program Implementation Plan*, provided as CW-YECL-27(d) Attachment 1.

Demand-Side Management (DSM) Program Portfolio for the Yukon

FINAL
PROGRAM IMPLEMENTATION PLAN

Date: May 30, 2013

Submitted to:
Yukon Energy Corporation
Yukon Electrical Company Limited

Submitted by:
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Executive Summary

This report presents the program implementation plan (PIP) for the Yukon demand-side management (DSM) program portfolio. It represents the final step in the YEC and YECL's DSM planning process, which began with the completion of the study entitled *Conservation and Demand Management Potential for the Yukon*.

The PIP defines the full scope of operational and transactional infrastructure that is required to operate the DSM program portfolio. As such, the PIP presents the performance indicators, the targets, the deliverables, the human resource requirements, the roles and responsibilities, and the budgets required to operate the DSM Program Portfolio over a full five year cycle. Particular emphasis is given to the Program Portfolio's operational requirements in its first year of activity.

The Program Implementation Plan, which is an extension of the program design document, *Demand-Side Management Program Portfolio for the Yukon*, is accompanied by an evaluation, measurement and verification (EM&V) plan.

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1. Introduction

Yukon residents rely on electricity not only to live meaningful, healthy lives but also to support and strengthen the economy. Given the concerns over environmental implications including climate change, and the limited generating capacity in the Yukon, there is growing interest not only in how electricity is generated, transmitted and distributed but also how efficiently it is used at the customer's end. In the Yukon, as well as in a growing number of North American jurisdictions, how electricity is generated and used is being closely analyzed to find innovative ways of meeting individual and corporate energy service needs while minimizing pollution and the creation of greenhouse gases.

In response to these conditions, the Yukon Energy Corporation (YEC), Yukon Electrical Company Limited (YECL) and the Yukon Government collaboratively commissioned a comprehensive study of the opportunities for electricity demand-side management (DSM) within the Yukon. That study, entitled *Conservation and Demand Management Potential for the Yukon 2011*, was completed in January 2012 and revealed a significant cost-effective potential for electricity DSM in the Yukon. Based on those findings, the YEC and YECL developed a suite of residential and commercial sector program offerings that will enhance the Yukon's electricity DSM program portfolio and provide incremental annual electricity savings of 9.3 GWh/yr by the fifth year of the program. The results of the development work are presented in a report, entitled *Demand-Side Management Program Portfolio for the Yukon*, which was completed in September 2012.

This report, which is the final step in the DSM planning process, provides a program implementation plan (PIP) suitable for submission to the Yukon Utilities Board, together with an evaluation, monitoring and verification (EM&V) plan.

1.1 The Planning Process

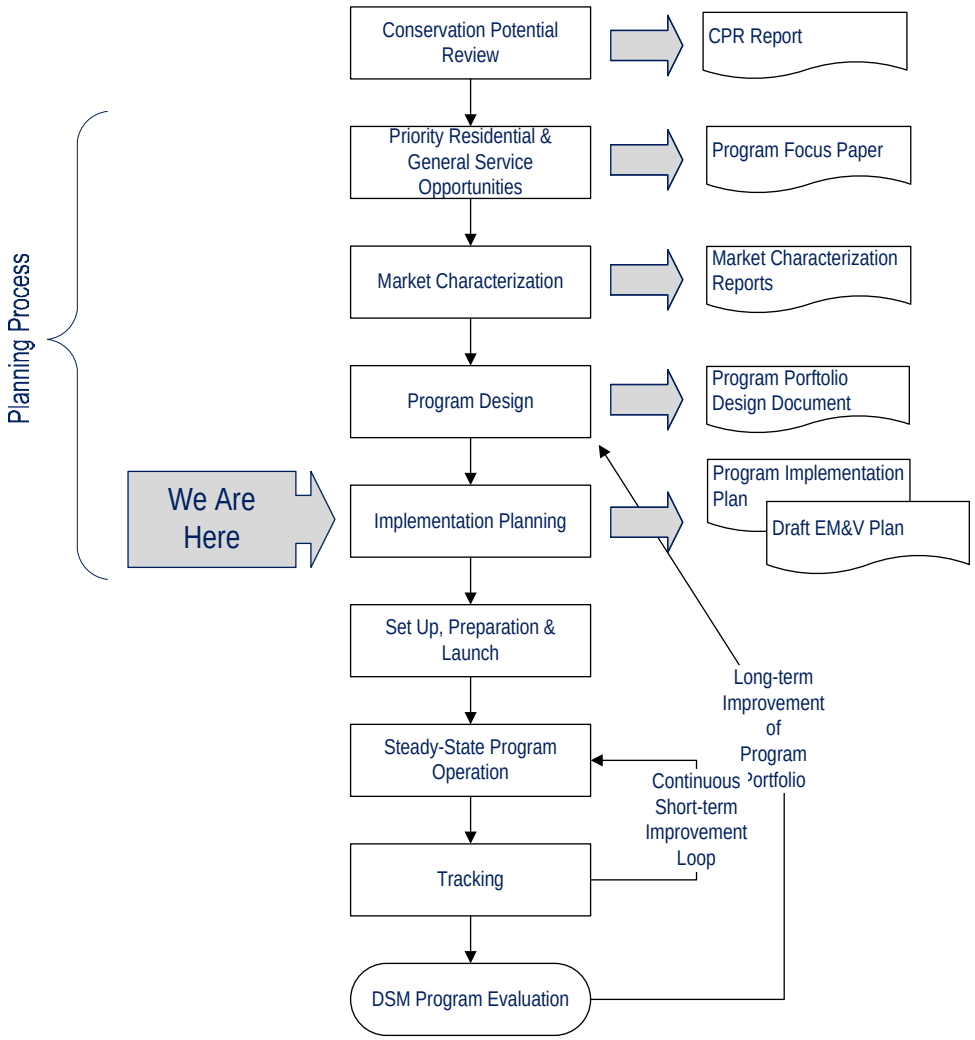
The DSM Program Implementation Plan presented in this report is the product of a multi-step process, which was designed to gather and analyze the data necessary to determine optimum program structure and cost-effective design.

The planning process was organized into 4 major steps:

- Step 1: Priority Residential and General Service Opportunities
- Step 2: Market Characterization
- Step 3: Program Design
- Step 4: Program Implementation Planning

Exhibit 1 provides a graphic of the steps involved in the planning process and its relationship to the Yukon Conservation Potential Review (CPR) results.

Exhibit 1: Program Planning Process



A brief description of the main steps shown in Exhibit 1 is provided below. More detailed information is provided in the appendices that accompany this report.

Step 1: Priority Residential and General Service Opportunities

This first step in the planning process was to determine which of the several hundred technologies and measures analyzed in the 2011 Yukon CPR should provide the initial program focus.

As a starting point the extensive listing of individual measures and technologies contained in the CPR results were screened. The priority opportunities were bundled into potential program elements and each was subjected to further detailed market research.

Step 2: Market Characterization

This market research step provided the program design team with a comprehensive understanding of the key factors influencing market penetration of the electricity efficiency technologies and measures; these findings informed the design of the specific programs and activities.

The detailed market research employed a variety of data collection methods and included a broad range of Yukon personnel involved in the supply, service, purchase and use of electricity efficiency technologies and measures. The research focused on developing clarity around four key areas, namely: market barriers, market structure, market actors, and baseline conditions.

Step 3: Program Design

The knowledge gained from the above market research provided key design inputs into the DSM program portfolio. For example, the understanding of market barriers was critical to the selection of appropriate activities or program offerings; similarly, a thorough knowledge of the market structure and major actors within the supply chain provided insight into potential partners and marketing strategies that will be most effective.

The collection of data on baseline conditions provided important inputs to the cost effectiveness testing that is critical to the program design process, and to the eventual program evaluation requirements.

Step 4: Program Implementation Planning

The last step in the planning process, which is the focus of this report, is to determine the full breadth of operational requirements to create the designed DSM portfolio's transactional and operational infrastructure, and to operate the portfolio in its first year.

This report also includes the performance indicators, the targets, the deliverables, the human resource requirements, the roles and responsibilities, and the budgets required to operate the DSM program over its full five year cycle.

1.2 Report Presentation

The remainder of this report is organized and presented in the following sections:

- Section 2 introduces the implementation approach, work package structure and schedule.
- Section 3 describes the resources required to operate the DSM portfolio.
- Section 4 defines the proposed management procedures.
- Section 5 provides an integrated communication plan for the General Service and Residential programs.
- Section 6 provides a summary of the operational budget, and a description of the main cash flows between the utilities and the ratepayers, and between utilities.

2. Work Plan

Section 2 presents an overview of the proposed four-phase approach to program implementation, an outline of the recommended work package structure (WPS), and a preliminary 'high-level" schedule.

2.1 General Approach

The goal is to launch most of the program elements concurrently during the first three quarters of program operation and to have the program elements reach steady-state operation before the end of the first year of operation.

A four-phase approach is envisioned for the launch of the program portfolio.

- Phase 1: Mobilization of the Implementation Team
- Phase 2: Preparation and Launch
- Phase 3: Training and Transition to Regular Operation
- Phase 4: Steady-State Program Operation

The YEC Energy Conservation (EC) Manager and the YECL DSM Supervisor will lead the launch of all of the program elements. The YEC Energy Conservation Manager will be responsible for finalizing the detailed work plan, and for updating the work plan on a sliding quarterly basis.

It is envisioned that during Phases 1 and 2, the Core Team (about four people) will be supplemented by external DSM experts (Launch Contractor), as required.

Further discussion of each step is provided below.

Phase 1: Mobilization of the Team

Highlights of Phase 1:

- The Utilities will select a Launch Contractor and mobilize the Core Team under the lead of the YEC Energy Conservation Manager (in collaboration with the YECL DSM Supervisor). The selected Launch Contractor will be responsible for supporting, engaging and training the local staff, and establishing many of the key program procedures and tools that will be essential to successful program operation in the four years that will follow. Further detail on team and member qualifications is provided in Section 3.1.
- The detailed short-term work plan that will be provided as part of this Implementation Plan will be the starting point for the Core Team and Launch Contractor; however, it is expected that the YEC Energy Conservation Manager will adapt the detailed work plan to his/her own management preferences and style.

Phase 2: Preparation and Launch

The team will execute the short-term work plan. This includes:

- Developing and initiating the operation of the DSM office, including:
    - The transactional infrastructure (e.g. front-end forms, agreements, notice & letter templates); and

  - The operational infrastructure (e.g. back-end forms and reports, procedures and tracking system).[1]

- Executing the engagement and communication strategy, including:
  - The launch tactics (e.g. new web page content, brochures, press release, and perhaps a press conference), and
  - The establishment of the engagement & communication coordination function(s) (e.g. monitoring and reacting to program uptake; planning, developing and delivering new communication and education tactics as needed; maintenance of the webpage and program documentation; and surveillance of public-relations opportunities).

The Utilities will go public with the program offerings during Phase 2. The launch tactics will be delivered in close collaboration.

Phase 3: Training and Transition to Regular Operation

As the first program transactions are processed, the team will undoubtedly identify less-than-optimal transactional materials and procedures. Necessary corrections and streamlining of the transactional and operational infrastructure will be applied, as applicable.

The Launch Contractor will provide training on DSM planning, operations and customer engagement through a mentor/protégé working relationship with the local staff and their involvement in the preparation and launch tasks. The Launch Contractor will use a wide array of training vehicles including: lectures, webinars, readings, quality assurance, and the development of job aids like operation manuals and decision support spreadsheets.

The Launch Contractor will ensure a smooth transition of all the tasks and responsibilities to the core team and then phase out of program operation.

Phase 4: Steady-State Program Operation

The Core Team will:

- Operate the DSM back-office.
- Plan and execute engagement, education and communication tactics.
- Conduct some site visits and verifications.
- Monitor program uptake and other key performance indicators.
- Review program results, adapt, plan and lay out the budget for next year.
- Seek continuous improvement by monitoring suggestions from the operation personnel and market actors, and by planning and implementing the applicable changes.
- Manage the evaluation, measurement and verification (EM&V) contractor; provide the program data as requested by the contractors; and provide feedback on the EM&V draft reports.
- Manage other contractors that may be involved in the operation of the program.

[1] Establishing clear procedures and standards with respect to permissions and privacy will be a critical element of this step.

2.2 Work Package Structure

The work package structure (WPS) will be used as the budget breakdown structure (BBS), which will also be used for time and expense tracking purposes and managerial accounting. It should be noted that the WPS/BBS is subject to change over the course of the 5-year DSM portfolio operation as program elements are likely to evolve over the period in response to changing market conditions. The proposed WPS for the Residential and General Service DSM programs is outlined below in Exhibit 2.

Exhibit 2: Proposed Work Package Structure for the Yukon DSM Programs

WP1 General Service Program

- WP1.1 Program Management
  - WP1.1.1 General Management Time & Materials (YEC)
  - WP1.1.2 Tracking System Development & Maintenance (YEC)
- WP1.2 Engagement, Training and Communication
  - WP1.2.1 Direct Customer Engagement (YECL)
  - WP1.2.2 Training and Indirect Communications (YEC)
- WP1.3 Lighting Redesign and Equipment Incentive
  - WP1.3.1 Time & Materials (YEC)
  - WP1.3.2 Incentive Disbursement (YEC)
- WP1.4 Energy Star Computer Incentive *(ibid)*
- WP1.5 High-Efficiency Refrigeration *(ibid)*
- WP1.6 New Construction Incentive *(ibid)*

WP2 Residential Program

- WP2.1 Program Management *(Same sub-WPS as for WP1.1)*
- WP2.2 Engagement, Education and Communication *(Same sub-WPS as for WP1.2)*
- WP2.3 LED Lighting and Automotive Heater Timer Rebates *(Same WPS as for WP1.3)*
- WP2.4 Promotion of Low-Cost Energy-Efficient Products *(ibid)*
- WP2.5 Cold-Climate Heat Pump and Ground-Source Heat Pump System Initiative *(ibid)*

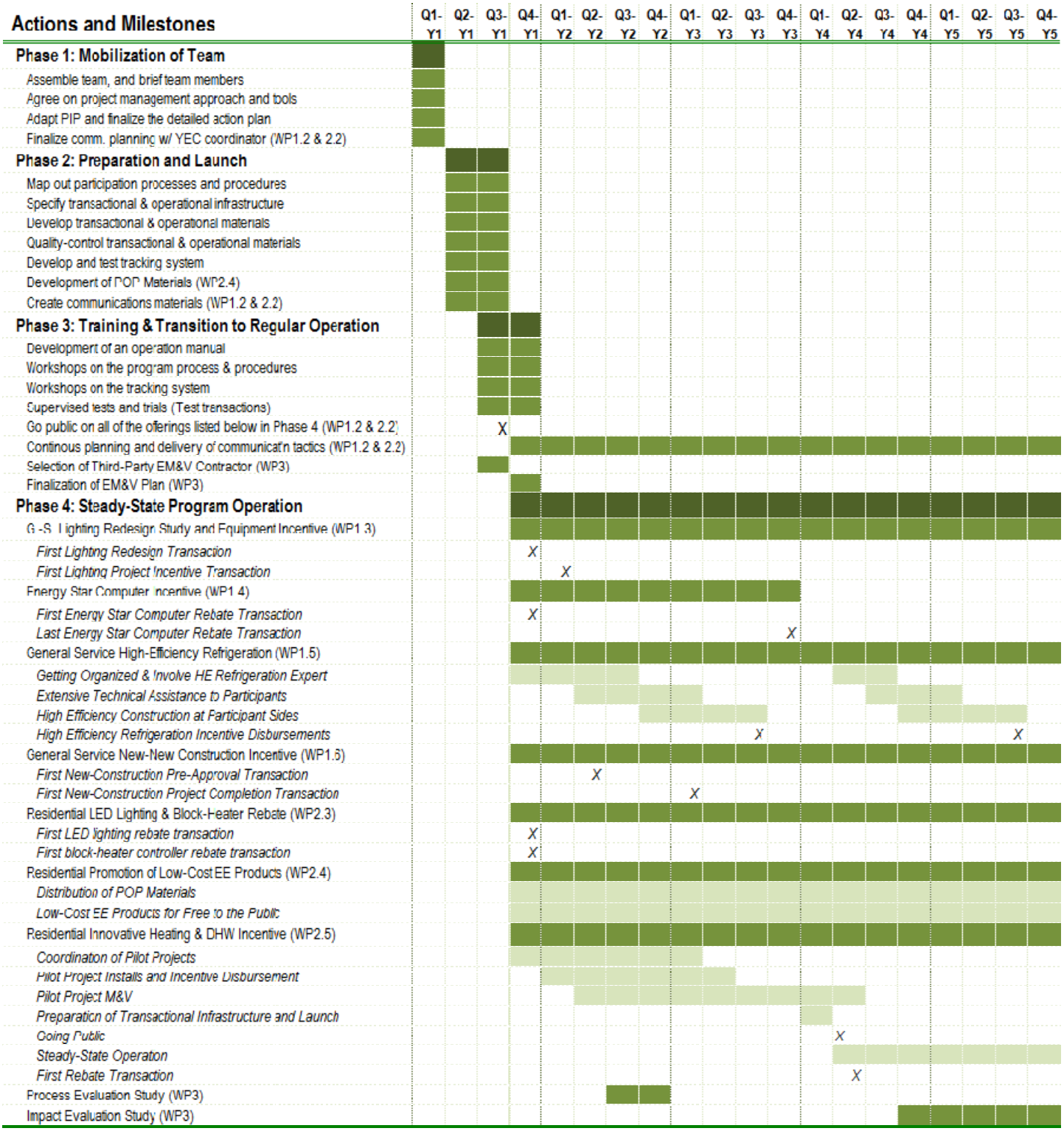
WP3 Evaluation, Measurement and Verification

(To be determined once the Evaluation, Measurement and Verification Plan is finalized with the EM&V Contractor)

2.3 High-Level 5-Year Schedule

Exhibit 3 shows the proposed schedule for implementing the program. A detailed action plan for Year 1 is presented in Appendix A.

Exhibit 3: High-Level Gantt Chart of the Program Portfolio Implementation



3. Resource Plan

Section 3 defines the resources required to operate the program (human resources, contractors and information technologies) and provides general procurement guidelines.

3.1 Human Resources Plan

Based on the approach described in Section 2, approximately four full-time equivalent workers (FTE) will be required for the management and operation of the General Service and Residential Programs. This core program operation team (Core Team) of four workers will be employed directly by the Utilities, jointly funded by the Utilities and under the brand inCharge (the joint utility brand for DSM. Contractors will be added and corporate staff will support the team on an as-needed basis.

The FTEs of the Core Team will likely be formed as follows:

- Two will be YEC employees. Their primary responsibility areas will be program management, in-direct communications, tracking, and evaluation, measurement and verification.[2]
- Two will be YECL employees[3]. Their primary responsibility area will be direct customer engagement and back office work.

The Core Team will be based in the Yukon in the Utilities' existing office space. Candidates for the Core Team include existing and new employees that will work on the General Service and/or the Residential Program. It is expected that core team staff will be added gradually over the first four quarters as activities ramp up.

The core program team will also need the assistance of external DSM experts (contractors). These external DSM experts will:

- Assist with the launch of the program portfolio until fully operational.
- Establish the processes and procedures and provide training to the Core Team, as needed.
- Have an exit strategy. Minimal involvement of external experts is expected beyond the third phase, aside from their involvement in EM&V, and in the High-Efficiency Refrigeration program element.

New hires, if required, do not need to be DSM program experts as they can be trained and assisted by DSM experts. They will be recruited through the standard human resource procedures of the Utilities based on standard job descriptions for similar work and experience-level requirements.

The expertise and external human resource requirements are bundled into work packages as presented in Section 3.2 – Procurement Plan.

[2] Further details on roles and responsibilities are to be laid out in Section 4.1.
[3] The costs associated with the YECL DSM Supervisor (Coordinator) are accounted for in YECL costs outside of the Marbek Program Design

3.2 Procurement Plan

Exhibit 4 provides a preliminary draft of the procurement plan. Each entry in the table is to become a contract with a service supplier. These are service contracts only. No equipment will be purchased to deliver the program. The assumption was made that office space, office IT infrastructure and office stationery are to be provided by the suppliers. The role and responsibilities of inCharge personnel mentioned in Exhibit 4 are to be laid out in Section 4.1 and 4.2.

Exhibit 4: Preliminary Procurement Plan

#	Contract Title	Amount (Approx.)	Start/End	Contract Awarded	Notes on the Scope of Work	Comments on Prospective Suppliers
1	DSM Portfolio Preparation & Launch Support a.k.a. "Launch Contract"	Between $230,000 and $290,000	Start: Y1-Q1 End: Y2-Q1	Before Y1-Q1	Support the YEC EC Manager and YECL DSM Supervisor with project management and coordination; Plan, design, and create transactional and operational infrastructure for all program elements. Finalize prescriptive incentive levels, eligible products and specifications, and customer incentive levels. Design and create DSM tracking system, set-up and start the operation of the tracking system. Support the YEC EC Manager, YECL DSM Supervisor and Communication Contractors with the finalization of the communication plan, finalization of the list of tactics and schedule, and with the production of communication content. Supervise the testing and tuning of the transactional infrastructure, operational infrastructure and tracking system based on the first DSM transactions. Training inCharge core staff in DSM launch and planning though multiple means: lectures, webinars, readings, ride alongs, job aids, development of operation manuals, mentoring, learning-by-doing, delegation of tasks, and quality control. Support and training of the YECL program Back-Office Coordinator on operational procedures and tracking, and YECL Customer Engagement Officer on engagement approaches and tracking, transfer responsibilities and send off. Support YEC with "special" program elements: General Service HE Refrigeration, Residential Innovative Heating System Program element, and Residential low-cost energy efficiency product element.	Consulting firm with DSM expertise, and DSM program implementation experience. Some energy engineering qualifications required.
2	Multiple contracts / Expert	Between $200,000 and $250,000	Multiple contracts over the course of the	Depending on the contract	Provide technical assistance to participants as part of the General Service HE Refrigeration program element. Deliver training course to Yukon equipment or service providers (if any, when	Highly qualified energy engineer(s); most likely freelancers. Consultant with specific expertise as

#	Contract Title	Amount (Approx.)	Start/End	Contract Awarded	Notes on the Scope of Work	Comments on Prospective Suppliers
	consultants	in total	following period: Start: Y2-Q1 End: Y5-Q4		needed). Hands-on training to Yukon equipment or service providers (if any, when needed). If required, support EM&V contractor with updates to prescriptive incentive lists. Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).	needed.
3	Yukon DSM Portfolio Evaluation, Measurement and Verification a.k.a. EM&V Contract	Between $360,000 and $440,000	Start: Y2-Q1 End: Y5-Q4	Y1-Q4	Finalize the evaluation, measurement and verification plan. As part of the above, review the tracking system and procedures, and recommend changes to maximize the value of EM&V. As part of the above, establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, etc. As part of the above, collect some additional market baseline information if and as needed. Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6 quarters after the launch). As part of the above, do some quality control/quality assurance of the program impacts as computed by the tracking system. Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.	Consulting firm with experience in DSM program evaluation, measurement and verification. Program-level evaluation experience is a minimal requirement. Project-level measurement and verification experience is beneficial but not essential.

3.3 Program Tracking Database

The central component of a tracking system is the database. The other key components are internal forms and procedures to input data, data quality control and assurance measures, and reports.

Exhibit 7 identifies three types of DSM program tracking databases, together with a summary of their strengths and weaknesses.

Exhibit 7: Three Types of DSM Program Tracking Databases

#	Type of Program Tracking Database	Strengths	Weaknesses
1	Database-like Spreadsheets	Very inexpensive (a few thousand dollars). Easy to find people to change and adapt the database – people with qualifications in Excel are relatively easy to find. Can be shared on file-sharing sites.	Limited inputting and query/reporting features. Spreadsheets are not organized as a database by default – making the file a "database-like set of spreadsheets" requires special care. Technical limitations in terms of: number of sites the database will be accessible from, amount of data in the same file, tendency for MS-Excel to crash. Versioning and preventing multiple copies of the database to circulate will be a challenge. It is challenging to record changes of the entries (for example: program participation status), and report on the history of each entry later.
2	Simple Database Built on a Database Platform (e.g. Access, MySQL) – from scratch or by modifying an existing program tracking database	None of the disadvantages above. Less costly than the option below. The system remains relatively simple and thus can be modified more easily. Can be shared on file-sharing sites, such as Sharepoint.	More costly than Database-Like Spreadsheets (a few tens of thousand dollars).
3	Sophisticated customized Customer Relationship Management software	Multiple advanced features, Integration with other database used by the utility.	Very costly (millions of dollars). Difficult to service – requires doing business with the initial developer.

The use of a database-like spreadsheet tracking system is recommended, as it best matches the Utilities' needs. It is assumed that the team will lead the development of the tracking system with the support of the Launch Contractor, as required, during the startup phase. The team will likely use commercially-available spreadsheet software like Microsoft Excel. The Launch Contractor will provide support to the Utilities to create the blueprint of the database and the blueprints of the procedures surrounding the use of the database.

The workbook will be built like a relational database to ensure that: data are well organized; data quality control/quality assurance and clean-up are easy to perform; and, data analysis and reporting are fully supported.

To perform like a relational database the workbooks will include the following characteristics:

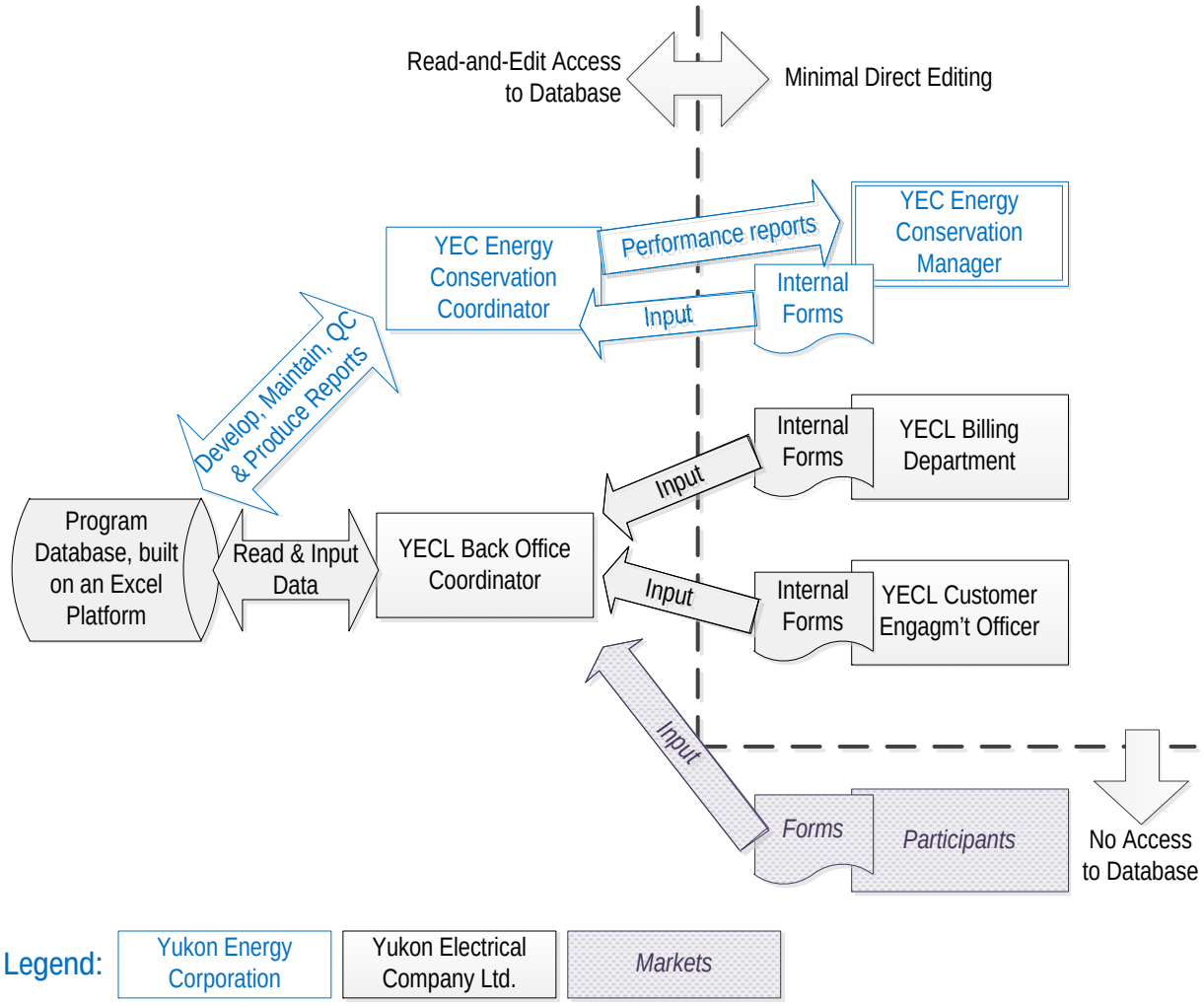
- Be made of a set interlocking "data storage" tables (worksheets).

- Keep the output sheets, charts and reports, and data storage tables in separated tabs.
- Present each entry in its own row in the data-storage tables.
- Identify each entry with its own unique identification number.

The proposed data flow through the program tracking database is presented in Exhibit 8. As illustrated, the YECL Back-Office Coordinator and the YEC Energy Conservation Coordinator will be the database custodians. It is recommended that all other YEC and YECL personnel perform minimal direct editing in the database, as illustrated in Exhibit 5.

Options for other utility staff to feed information into the database include: sending an email to YECL Back-Office Coordinator; populating and sending an internal form; or directly forwarding the paperwork sent in by participants. The YECL Back-Office Coordinator will receive the data, validate the data, and then enter it into the data tables. The YEC Energy Conservation Coordinator will be responsible for reporting, directing traffic, and quality controls.

Exhibit 5: Data Flow through the Program Tracking Database



The program tracking database will be the responsibility of the YEC Energy Conservation Manager with access granted to employees from both companies.

At the end of the program implementation stage, there are two documents that, when combined, will be used for the development of the tracking database:

- The PIP: This section and Section 4.7.
- The list of researchable issues as part of the EM&V Plan.

During startup, the team will initiate the database development with the drafting of the following charts, later to be used as blueprints for the system.

- The detailed program participation process diagram.
- The tracking database architecture chart.

4. Management Plan

The management plan presents the recommended procedures required to balance the requirement to operate and adapt the DSM portfolio to changing market conditions and the requirement for the oversight entity (either or both the YUB and the YEC/YECL Management Committee) to review how ratepayer monies are spent.

The management plan is organized and presented in the following sections:

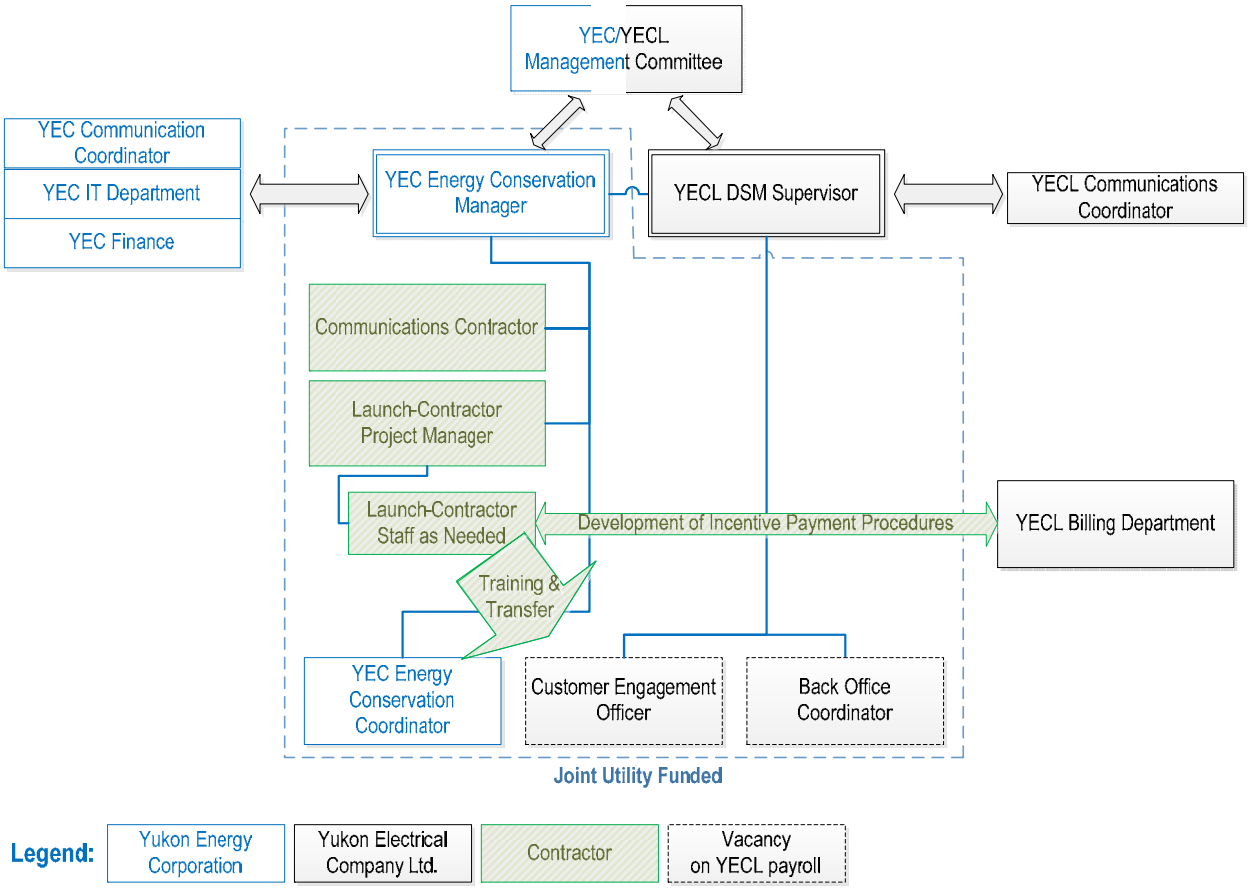
- Roles and responsibilities during program start up[4]
- Roles and responsibilities during full program operation
- Goals and performance tracking
- Operational reporting and planning
- Contingency plan
- Standards, policies and guidelines
- Information flow mapping

[4] Given the shift in roles and activities that occurs between program startup and full operation, this PIP presents the roles and responsibilities separately.

4.1 Roles and Responsibilities during Program Startup

Exhibit 6 presents the organization chart for Phases 1, 2 and 3 of the DSM portfolio delivery (mobilization of the team, preparation, launch, and transition to regular operation). The preliminary roles and responsibilities of each party are subject to change based on YEC or YECL internal organization, changing market conditions, and early program results. An explanatory note is presented in tabular format following the chart.

Exhibit 6: Organization Chart for the Launch of the DSM Portfolio



Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Coordinate with YECL DSM Supervisor to ensure business needs are met. • Procurement of the services of a Launch Contractor and Communications Contractor. • Coordination between the positions or resources shown in Exhibit 6. • Update/finalization of the detailed work plan, project activity monitoring, and then of the update of the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the contractors' deliverables. • Update/finalization of the communication plan.

Position	Payroll	Role/Responsibility during DSM Portfolio Launch
		• Control and approval of the engagement plan developed by the direct Customer Engagement Officer. • Jointly responsible for the public relations activities on behalf of inCharge with YECL DSM Supervisor. • Jointly responsible for development of communications content (examples: website content, print-media content and social media if any) with YECL DSM Supervisor and supported by the YEC and YECL communications coordinators.
Launch Contractor	Contractor for YEC	• Support YEC Energy Conservation Manager and YECL DSM Supervisor on project management. • Support YEC Energy Conservation Manager, YECL DSM Supervisor and communication contractors in laying out the program offerings, incentive levels and eligibility criteria to target markets in communication materials. • Finalize the prescriptive and custom incentive levels and eligibility criteria. • Update of the DSM cost-effectiveness modeling. • Finalize or develop the detailed blueprints and specs of the program element processes. • Development of materials that form the transactional and operational infrastructure. • Create the blueprint for the database and the blueprints of the procedures surrounding the use of the database. • Train core utility staff in DSM launch and planning though multiple means: lectures, webinars, readings, ride alongs, job aids, development of operation manuals, mentoring, learning-by-doing, delegation of tasks, and quality control. • Train core utility staff in application processing, and use of the tracking system. • Testing/Processing the first transactions. • Identification of the low-cost products that are to be promoted under the inCharge brand, and support to the YEC Energy Conservation Manager, YECL DSM Supervisor and communications coordinator in the creation of POP material (wrt: Residential Promotion of Low-Cost Energy-Efficient Products program element). • Advisory for the Customer Engagement Officer, the YEC Energy Conservation Manager and the YECL DSM Supervisor to find heating pilot-project sites, and recruit trusted HVAC contractors (wrt: residential innovative heating program element). • Advisory for the YEC Energy Conservation Manager to find a trusted high-efficiency refrigeration contractor and for the engagement officer to start engaging with the prospective High-Efficiency Refrigeration program participants (wrt the General Service HE Refrigeration program element). • Advise the YEC Energy Conservation Manager and YECL DSM Supervisor in the selection of an EM&V contractor.

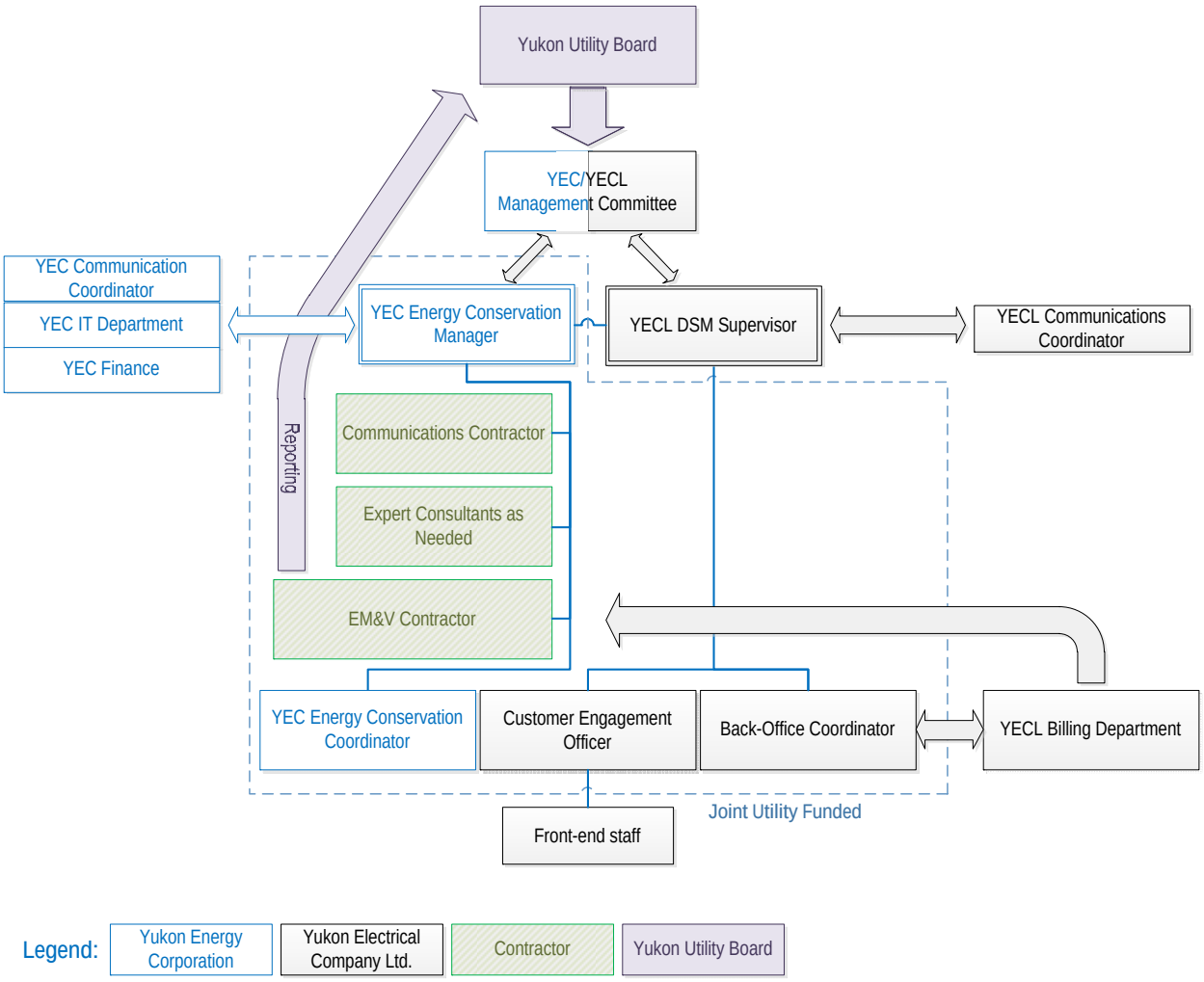
Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YEC Energy Conservation Coordinator	YEC	• Is integrated in the launch team and works on the tasks laid out by the Launch Contractor. • Work closely with the Launch Contractor to: o Develop the tracking system/program database. o Build the technical reference manuals (deemed savings and stipulated net-to-gross ratio) and connect it to the tracking system. o Finalize the KPIs and targets. o Prepare templates for the quarterly and yearly performance reports. o Draft the operations manual. • Support the YEC Energy Conservation Manager with the drafting of the first quarterly and yearly program reports.
YECL Billing Department	YECL	• Collaborates with the Launch Contractor to establish the YECL on-bill incentive payment procedures for when the recipient of the incentive is direct YECL customer.
YEC Finance	YEC	• Supports the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS). • Collaborates with the Launch Contractor to establish the YEC incentive payment procedures for when the participants are eligible direct YEC customers.
YEC Information Technology (IT) Department	YEC	• Support the YEC Energy Conservation Coordinator and the Launch Contractor during the development of the tracking system. • Collaborate with the Launch Contractor and YECL IT department to store the tracking database, share it, protect it, and manage levels of access. • Collaborate with the Communication Contractors and the Launch Contractors to develop the inCharge website, and determine where the inCharge website will be hosted (on YEC service, YECL server or a third-party server – to be determined).
Communications Contractor	Contractor for YEC	• Develop the inCharge website, managed by the YEC Energy Conservation Manager and with the support of YEC IT department as needed. • During the preparation and launch (phase 1 to 3): work on the branding, templates and graphic materials, and anything requiring significant graphic design. • Support YEC Energy Conservation Manager and YECL DSM Supervisor in the review and finalization the communication plan. • Design POP and other educational materials as part of the Residential Promotion of Low-Cost Energy-Efficient Products.
YEC Communications Coordinator	YEC	• Support development of communications material (examples: website content, print-media content and social media if any) with YEC Energy Conservation Manager.
YECL Corporate Communications & Customer Relations	YECL	• Support development of communications material (examples: website content, print-media content and social media if any) with YECL DSM Supervisor. • Recruit and hire a DSM supervisor sometime between Y1-Q1 and Y1-Q3.

Position	Payroll	Role/Responsibility during DSM Portfolio Launch
YECL DSM Supervisor (New hire)	YECL	• Jointly accountable with the YEC Energy Conservation Manager for deliverables (eg schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Jointly responsible for the public relations activities on behalf of inCharge with YEC Energy Conservation Manager. • Jointly responsible for development of communications content (examples: website content, print-media content and social media if any) with YEC Energy Conservation Manager and supported by the YEC and YECL communications coordinators. • Review and approve the final detailed work plan to be created by the Launch Team. • Review and approve the final communication plan. • Quality control/quality assurance of all of the communication materials being generated by the Launch Team and the Communications Contractor. • Recruit and hire a Customer Engagement Officer and a Back-Office Coordinator sometime between Y1-Q2 and Y2-Q1. • Work on the first direct engagement plan with the Customer Engagement Officer, develop direct-engagement key performance indicators (KPIs) and goals, and monitor KPIs.
Customer Engagement Officer (New hire)	YECL	• Work on the first direct engagement plan. • Test-drive the direct engagement communications resources (brochures, website content, etc.) with early actual customers, and provide feedback (quality, effectiveness, how easy to understand, etc.). • Gather data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS as presented in Section 2.2. • Collaborate with YECL billing department and the Launch Contractor to establish the YECL on-bill incentive payment procedures for when the recipient of the incentive is a direct YECL customer.
Back-Office Coordinator (New hire)	YECL	• Process the very first transactions, and work with the Energy Conservation Coordinator and Launch Contractor to resolve the issues that arise.

4.2 Roles and Responsibilities during Full Program Operation

Exhibit 7 outlines the anticipated organization of key roles once the program is fully launched and is in full operation. An explanatory note is presented in tabular format following the chart.

Exhibit 7: Organization Chart during Full Program Operation



Position	Payroll	Role/Responsibility during Full Operation
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Coordinate with YECL DSM Supervisor to ensure business needs are met. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Prepare reports and documents to be filed with the YUB under the supervision of YEC/YECL Management Committee (most likely made of extracts from the aforementioned reports,

Position	Payroll	Role/Responsibility during Full Operation
		budgets and plans). • Procurement of the services of the EM&V contractors, Communications Contractor, and expert consultants when needed. • Coordination between the positions or resources shown in Exhibit 7. • Update the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the contractors' deliverables. • Update the communication tactic calendar on a sliding quarterly basis. • Monitor the customer engagement KPIs. • Work jointly with the YECL DSM Supervisor to update and approve the engagement plan updates by the YECL Customer Engagement Officer. • Public relations activities on behalf of inCharge brand. • Continuous development of new communications content, or update of existing contents (as needed): website, print-media, social media if any, etc.
YEC/YECL Management Committee	YEC or YECL	• Review and comment on the reports, budgets and planning drafted by the YEC Energy Conservation Manager and the YECL DSM Supervisor. • Provide directions to the YEC Energy Conservation Manager and YECL DSM Supervisor on the reports and documents to be filed with the YUB, review and approve these documents and file them. • Work with the YEC Energy Conservation Manager and YECL DSM Supervisor to address comments from the YUB and interveners.
YEC Energy Conservation Coordinator	YEC	• Maintain the tracking system, control the quality of the data inputted into the system. • Extract reports from the accounting system and the tracking system for the YEC Energy Conservation Manager (KPIs, charts, etc.). • Supports the YEC Energy Conservation Manager with the development of quarterly or annual reports. • Coordinate with YEC Finance to pay incentive to YEC direct customers. • Support the YEC Energy Conservation Manager with EM&V, with selecting the EM&V contractor, and with the coordination with the EM&V contractor. • Support the YEC Energy Conservation Manager with selecting technical experts as needed, and with the coordination with these experts. • Provide technical assistance to all inCharge personnel as needed.
YEC Communications Coordinator		• Support public relations and communications needs of inCharge brand. • Support YEC DSM Supervisor as needed.
YECL Back-Office Coordinator	YECL	• Handles applications and completion forms. • Feeds the tracking system with transactional information as required in the operation manual. • Proceeds with in-situ verification of a few transactions (spot-check verifications that are going to be selected randomly). • Coordinate with YECL Billing department and provide support, as needed, for YECL on-bill incentive payments.

Position	Payroll	Role/Responsibility during Full Operation
YECL Billing Department	YECL	• Proceed with incentive payment (on-bill or otherwise) for when the recipient of the incentive is direct YECL customer based on procedures established during startup. • Send utility billing data to EM&V Contractor as needed and when needed, directly to the contractor, and under a confidentiality agreement with the contractor.
YEC Finance	YEC	• Support the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS). • Proceed with incentive payment (on-bill or otherwise) for when the recipient of the incentive is direct YEC customer based on procedures established during startup.
YEC Information Technology (IT) Department	YEC	• Support the Energy Conservation Coordinator with tracking system maintenance. • Collaborate with the Communication Contractor to maintain the inCharge website.
Communications Contractor	Contractor for YEC	• Support YEC Energy Conservation Coordinator in the update of the list of communication tactics and production schedule. • Design communications materials as required by the YEC Energy Conservation Coordinator – anything requiring substantial graphic design.
YECL DSM Supervisor	YECL	• Jointly accountable with the YEC Energy Conservation Manager for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Review and approve of the detailed work plan when updated by the YEC Energy Conservation Manager. • Work jointly with the YEC Energy Conservation Manager to update and approve the engagement plan updates by the YECL Customer Engagement Officer. • QC/QA of all of the communication materials being generated by the YEC Energy Conservation Manager and the Communications Contractor. • Supervise the update of the engagement plan with the Customer Engagement Officer, monitor key performance indicators (KPIs) and update the goals. • Support corporate social responsibilities and inCharge brand.
YECL Communications Coordinator	YECL	• Support public relations and communications needs of inCharge brand. • Support YECL DSM Supervisor as needed.

Position	Payroll	Role/Responsibility during Full Operation
Customer Engagement Officer	YECL	• Carry out direct customer engagement according to the plan. • Supports participants with their transaction face to face, on the phone or through emails. • Log the events or actions in order to compute the engagement KPIs. • Log program transactions (for example: program applications) that YECL channels to YECL Back-Office Coordinator with time stamps. • Track incentive reimbursements coming from YEC; and make sure there are no discrepancies between the tracking information of YECL and that of YEC. • Regarding the above, investigate any discrepancy as soon as possible. • Gathers data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS as presented in Section 2.2.
Yukon Utility Board (YUB)	YUB	• Look out for the interests of the rate payers and authorize the use of rate payers' monies on DSM. • As such, the YUB requires DSM to be implemented in a rigorous, cost-effective and optimal manner. All documents filed with them should demonstrate these attributes. • They achieve the above by asking questions and making comments on the reporting and planning documents filed with them.
Evaluation, Measurement and Verification (EM&V) Contractor	Contractor for YEC	• Finalize the evaluation, measurement and verification plan. • As part of the above, review the tracking system and procedures, and recommend changes to maximize the value of EM&V. • As part of the above, establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, and so on. • As part of the above, collect some additional market baseline information if and as needed. • Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6). • As part of the above, do some quality control/quality assurance of the program impacts as computed by the tracking system. • Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.
Expert Consultants	Contrac-tors for YEC	• Provide technical assistance to participants as part of the General Service HE Refrigeration program element. • Deliver training course to Yukon equipment or service providers (if any, when needed). • Hands-on training to Yukon equipment or service providers (if any, when needed). • Support inCharge staff as required, to update the prescriptive incentive lists (both the incentive level and the eligible products). • Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).

4.3 Goals and Performance Tracking

Program performance will be monitored by comparing key performance indicators (KPIs) with pre-established targets.

The program accounting system and tracking systems should report on the following KPIs for each program element:

1. Number of transactions and number of business days of average processing time
2. Incentive disbursement cost
3. Program cost and administration cost
4. kWh and kW savings (gross)[5]
5. Number of transactions being verified on site (to be determined with the YEC Energy Conservation Coordinator, triggered and coordinated with the YECL Back-Office Coordinator, and then validated by the EM&V Contractor)
6. Direct-engagement indicators (to be determined with the YECL engagement officer)
7. Indirect communications indicators (to be determined with YEC Energy Conservation Manager and the communications contractor)

The targets for KPIs (1) to (4) above were set out in the projection tables presented in the Program Design Document. KPIs (5) to (7) will be established during program set up in collaboration with the core program staff.

The utilities will aim at achieving a total net electricity savings that is equal to, or above, the totals presented in the DSM portfolio projections at a total cost that is equal to, or below, the totals presented in the DSM budget (See the Program Design document). However, the utilities will have the flexibility to move targets and budgets between the DSM program elements to adapt to changing market conditions and early program results. Quarterly budgets will also be flexible as long as annual budgets are complied with.

In addition to information for tracking the KPIs above, the team will designate a limited number of information items to be collected for administrative and technical verification, as well as planning and strategic decision purposes (e.g. participant information, house/building type, etc.).

All KPIs computed by the DSM accounting system and the tracking system(s) will be verified by a third-party evaluation, measurement and verification (EM&V) contractor. The EM&V contractor will also validate the approach to on-site verification, the information items being collected through the applications and forms for verification purposes, and the market indicators to be monitored.

In addition to the KPIs stated above, a few market indicators will be established and documented through EM&V to test the effectiveness of the delivery mechanisms and to seek evidence of market effects of the DSM portfolio.

The program activities will be tracked and performance will be reviewed according to the reporting and planning schedule presented in Section 4.4.

[5] The tracking system will report on net impact if a deemed net-to-gross ratio is used.

4.4 Operational Reporting and Planning

The DSM portfolio activities will be coordinated through an annual performance reporting and work planning process, supported by quarterly updates to the annual planning.

The YEC Energy Conservation Manager and YECL DSM Supervisor will draft the reports and plans, present them, discuss them and request approval by the YEC/YECL Management Committee. Together, the YEC Energy Conservation Manager, YECL DSM Supervisor and the YEC/YECL Management Committee will prepare summaries of the reports and plans to be filed with the YUB.

There are five components to the DSM operation management and accountability mechanisms:

- **Performance report(s) to the YEC/YECL Management Committee**: Lays out KPIs against targets, explanations and justification for these results, and other strategic information gathered.
- **Work plan(s) to the YEC/YECL Management Committee:** Presents the tasks that need to be accomplished in the next quarter and in the next year. Also, it will present an updated strategic orientation and the corrective actions that need to be taken in light of the performance of the DSM portfolio and its different program elements.
- **Budget(s) to the YEC/YECL Management Committee:** Presents the resources that are needed to accomplish the tasks stated in the work plans, highlights discrepancies from the initial budget, and provides a justification for the changes if any (including but not limited to DSM cost-effectiveness).
- **DSM summaries to the YUB:** Composed of relevant extracts from the aforementioned reports, plans and budgets.
- **Third-party EM&V reports to the YUB:** The three reports are the final EM&V plan (during Q1 of Y2), the process evaluation study (sometime between Q4 of Y2 and Q2 of Y4), and the impact evaluation study (Q4 of Y5). The EM&V reports will present a rigorous estimation of the impacts in terms of kWh and kW and constructive criticism of utility-based DSM operation in the Yukon.

Exhibit 8 summarizes the reports, plans and budgets, together with a preliminary schedule and preview of the content of each. EM&V reports have been included to show the differences in content between the internal performance reports and those developed by the third-party EM&V contractor.

Exhibit 8: Summary of Operational Reports, Plans, and Budgets

Document	Schedule	KPIs against targets, including tracked impact estimates	Update on detailed action plan, incoming communication tactics, & engagement plan	Qualitative on strategic DSM development (outside the KPIs)	Updated strategic orientations	Update of detailed program - element targets	Updated contingency plan	Financial report against budget (time, expenses, incentives)	Budget re-allocation between quarters and program elements	Next-year total DSM portfolio budget estimate	Next-year detailed budget for all of the program elements	Combined ex-post & ex-ante DSM cost-effectiveness modeling	KPIs and market indicators in full MBO framework	Forward-looking improvement recommendations	Verified program impact estimates
Internal Performance Reporting & Planning															
Annual Progress Report	January 31st for the next fiscal year	X		X				X				X			
Annual Work Plan	January 31st for the next fiscal year		X		X	X	X								
Preliminary Annual Budget	September									X					
Annual Detailed Budget	January 31st for the next fiscal year										X				
Quarterly Report	30 days following end of the quarter	X	X					X	X						
YUB Annual Summary	30 days following end of the quarter	X	X	X	X	X	X	X			X	X			
Third-Party Evaluation, Measurement and Verification															
Final EM&V Plan	Q1 of Y2												X		
Process Evaluation Rep.	Mid-course. Btw Y2-Q4 & Y4-Q2											X	X	X	
Impact Evaluation Rep.	Q4 of Y5											X	X	X	X

It is expected that the YUB Annual Summary will be a concise document made of extracts from the annual progress report, the annual work plan, and the annual detailed budget.

The Launch Contractor can support with reporting during the first year of operation in the following way: the Launch Contractor will draft and deliver their own quarterly and annual reports and plans to the YEC Energy Conservation Manager and YECL DSM Supervisor; who will then build on these drafts to generate the reports and plans for the YEC/YECL Management Committee.

The accounting system will be adapted and the tracking system will be built to generate tables and charts that will be integrated in the reports[6], plans and summaries in a seamless fashion. The accounting system and tracking system should make the reporting and planning less effort intensive. Besides, the quarterly report should be relatively lean and require a low level of effort.

The three last reports presented in Exhibit 8 are to be drafted by the EM&V Contractor, not the utilities, and will be filed directly with the YUB. However, the YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL Management Committee will be able to read early drafts of these reports, ask questions, highlight potential errors or omissions, and make comments on the reports before it is sent to the YUB.

All of the internal reports and plans (that is: the first four types of reports in Exhibit 8) should be made accessible to the EM&V Contractor under the confidentiality terms of the EM&V contract.

4.5 Contingency Plan

Exhibit 9 shows the project risks that have been identified by the team. These are the risks that will be monitored and reported on throughout the project in the contingency plan. Project risks are events that could affect the outcome of the DSM portfolio. These could include time, cost, quality, operational, cultural, communications, governance, stakeholders, resources, technology, etc. Severity and probability ratings will be reassessed by the team as necessary.

The risks were ranked from the most important to the least by using a ranking system that is presented in Exhibit 9.

Exhibit 9: Risk Analysis

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Communication	Wrong messages are sent to the market during program operation	M	H	6	Communication work will involve the YEC & YECL Communication Coordinators. Direct engagement will be done by the YECL Customer Engagement Officer under the supervision of YECL DSM Supervisor with support from YECL Corporate Communications.
Communication	Target audience not buying in to the key messages of the program	M	H	6	Early and extensive engagement with end-users, with market actors, and with stakeholders. We will listen, screen out outlying opinions, analyze and react. Sufficient program budget allocations to communications and engagement. Continuity of the communication activities ensured by cross-cutting communication coordinator.

[6] The combined ex-post & ex-ante DSM cost-effectiveness modeling can be done using the cost-effectiveness model used at the program design stage. It is not worth investing in building cost-effectiveness modeling capabilities inside the tracking system.
[7] High (H), Medium (M) and Low (L) are respectively worth 3, 2 and 1.
The Risk Rating is the result of: Severity x Probability

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Commu-nication	YEC Energy Conservation Manager stops actively managing external communications because his/her attention is focused on extinguishing fires (examples: fixing issues with the transactional materials, the tracking system, or dealing with specific large transactions)	M	H	6	Work closely with the YEC and YECL Communications Coordinators; if possible have the communications coordinators play a larger role. Delegate to the YEC or YECL Communications Coordinator his/her functions of surveillance and communication planning whenever he/she has to focus elsewhere. Rely on the YEC Energy Conservation Coordinator and core utility staff to fix issues with the transactional and operational infrastructure and tracking system, address issues with incentive payment and cash flow, and have the Back-Office Coordinator deal with the EM&V Contractor. Delegate as many reporting tasks as possible to the core utility staff.
Commu-nication	Company branded initiatives leverage inCharge branding and create customer confusion	L	M		Avoid similar or overlapping activities between companies and inCharge.
Technical	Residential innovative heating systems fail to perform in the Yukon and backfire	H	M	6	The implementation approach of the Residential Innovative Heating program element includes a 3-year pilot phase before we anticipate being able to turn it into a full-scale incentive program. It is a prudent implementation approach. We believe that inCharge can achieve and document a few successful installs, identify capable installers and, then build communication materials based on these.
Opera-tional	Delays happen with certain program elements during start up and hold back the entire program portfolio	M	H	6	In principle, the Utilities will be using a comprehensive implementation approach with all program elements being taken to market within the same 4-phase timetable. In reality, a few program elements will cause delays because the launch team will be confronted to unforeseeable issues. As long as these delays are only a few days, the program elements can remain in sync. However, if the delays start becoming problematic then the YEC Energy Conservation Manager will be allowed to let the schedule for some problematic program element slip compared to that of other program elements. The overall schedule might become out of synch but this could be preferable than delaying the launch of the entire DSM portfolio.
Opera-tional	Misunderstandings arise between YEC & YECL on role, responsibilities and/or on who is to blame for disappointing KPIs (this tends to happen when targets are not met)	H	M	6	Clear assignation of roles and responsibilities as per section 4.1 and 4.2 of the PIP. These sections should be revisited and refreshed on an annual basis as part of the annual performance reporting and planning cycle so they remain fresh in the mind of everyone in the core team. YECL Customer Engagement Officer is to produce an engagement plan, and agree on it with YEC.
Opera-tional	The resulting DSM program design fails to deliver expected results	M	M	4	The Utilities used evidence-based program design, and established realistic targets based on conservation potential review and a bottom up reality check. The Utilities claim the right to adjust program offerings mid-stream, after determining the root causes of low participation.

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Operational	Program participation uptake not picking up as planned	M	M	4	Sufficient budgets allocated to marketing and communications. Continuity of communication and marketing activities, and continuous tracking of uptake – See above how we will manage to ensure that communications is managed on a continuous basis. Flexibility to use other budgets and allocate them to marketing and communication in order to intensify the communication activities if and when needed.
Operational	Inaccuracy of the impact estimates (kWh and kW)	M	M	4	Support of the Launch Contractor's energy engineers to re-visit the deemed savings for the prescriptive conservation measures. Carefully plan, design and develop the tracking system and procedures; diligent and timely inputting of program data in the tracking system. Support from seasoned expert consultants to validate the engineering calculation of custom conservation measures and projects, and/or to carry out project-level measurement and verification. Third-party EM&V including validation of the deemed savings of the prescriptive measures early in the operation of the program (Y2-Q1) and final validation of the estimates generated by the tracking system during the impact evaluation study (Y5-Q3).
Planning	Approved plan, targets and schedule may not be achievable	M	M	4	Monitor milestones, monitor KPIs and execute project plan. Raise issues with the YEC/YECL management committee when presenting the quarterly or annual report. The reporting and planning procedures presented in Section 4.3 and 4.4 are flexible. Use this flexibility to change the strategy and change the approach to reach the total targets for the DSM portfolio.
Communication	Bad press	L	H	3	Communication work will jointly involve the YEC and YECL communication coordinators. Continuous monitoring of public relations activities handled by YEC Energy Conservation Manager, in coordination with YECL DSM Supervisor, YEC communication coordinator and YECL Corporate Communications & Customer Relations. Direct engagement of largest end-users by YECL DSM Customer Engagement Officer, direct engagement of key suppliers and retailers by YEC Energy Conservation Manager.
Operational	Understanding of needs/expectations of the Utilities by the Launch Contractor and/or the EM&V contractor	L	H	3	Carry out brief weekly or bi-weekly progress report (phone call or otherwise). Generate meeting minutes. The market characterization reports, the program design document, the PIP and the draft EM&V plan should be provided to the contractors. The KPIs and the market indicators are clearly laid out in the draft MBO framework presented in the draft EM&V plan. The MBO framework will be updated with the launch contractor, and then with the EM&V contractor.

Risk Area	Risk	Severity	Probability	Rating[7]	Contingency
Operational	Non-eligibility of participants	L	M	2	The Launch Team will create simple and clear eligibility criteria. The Launch Team will develop clear program internal procedures to validate eligibility. The core program team will lay out the eligibility criteria in an accessible fashion in the communications materials. The Customer Engagement Officer and/or the YECL front-end staff will be accessible to answer questions on the program. The YEC Energy Conservation Manager, YECL DSM Supervisor and engagement coordinator will provide clear information and training to YECL front-end staff so that they can provide the most up to date and accurate information to customers. This should be built in the communication plan and list of communication tactics and documented. The Customer Engagement Officer will be accessible for the prospective participants to ask questions.
Operational	Fraud from participants or lack of diligence from the program team to prevent fraud or errors	M	L	2	We seek to minimize fraud, not prevent it entirely. The mitigation measure must commensurate with the size of the rebate or incentive. We included site verification in some cases; on a spot-check basis and selected randomly. The Launch Team will lay out clear internal procedures to validate the information provided by the participants (when practical); the back office will have to comply with these and document his/her work. Compliance with the program internal validation procedures will be checked by the EM&V Contractor through the documentation left behind.
Operational	Operational areas outside of DSM (finance, IT, communications) may not have the resources to do their part	L	M	2	Ensure that the YEC/YECL Management Committee is involved to mediate issues and facilitate transition.
Planning	The appropriate resources won't be available to complete the project on time	L	L	1	Identify and secure appropriate resources with sufficient lead time. Update work plan at least quarterly (more often if possible) and validate availability of resources then raise resource constraint issues with the YEC/YECL Management Committee.

4.7 Information Flow Mapping

This section lays out three "maps" of the information flows between involved actors: YEC, YECL, the markets, the EM&V contractors, and the YUB. These three maps, without being completely exhaustive, should cover a large and representative portion of DSM portfolio activities, and include:

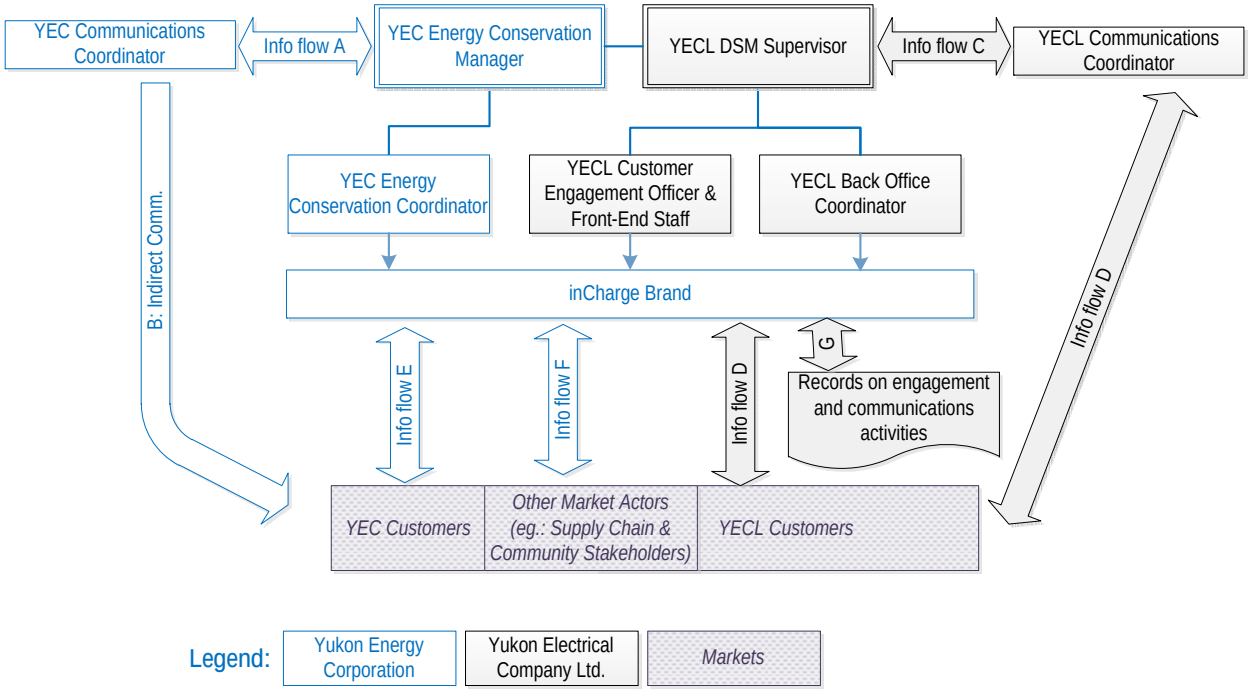
- Communications and direct engagement information-flow diagram
- Application processing and incentive payment information-flow diagram, and
- Performance reporting and EM&V information-flow diagram.

These three maps are provided below.

Communications and Direct Engagement Information Flow

The proposed information flow for communications and direct engagement activities is presented in Exhibit 10. An explanatory note is presented in tabular format following the chart.

Exhibit 10: Communications and Direct Engagement Information Flow Diagram



Explanation of the Information Flows – Communications and Direct Engagement

	Marketing and Communications
A	The marketing and communications plan, implementation of communications tactics, the inCharge website and print-media content will be developed jointly by YEC and YECL. The marketing and communications work will be carried out according to a number of communication KPIs; e.g. number of clicks on the inCharge website, number of participants at inCharge branded public events (public relations opportunities, etc.), number of brochures distributed, etc. Later, the YEC Energy Conservation Manager and the YEC Communication Coordinator will report on

Explanation of the Information Flows – Communications and Direct Engagement

	their performance based on the plan. The Manager will need to log some statistics and events to compute the KPIs throughout the year. It is more practical to keep this log separated from the main program tracking system. The communication KPIs will be determined by the YEC Energy Conservation Manager during the program setup.
B	YEC and YECL will jointly deliver messages to both YECL customers, YEC customers and other market actors indirectly through marketing and communication tactics. The YEC Energy Conservation Manager and the YEC Communication Coordinator will work with YECL to plan and develop bill inserts.

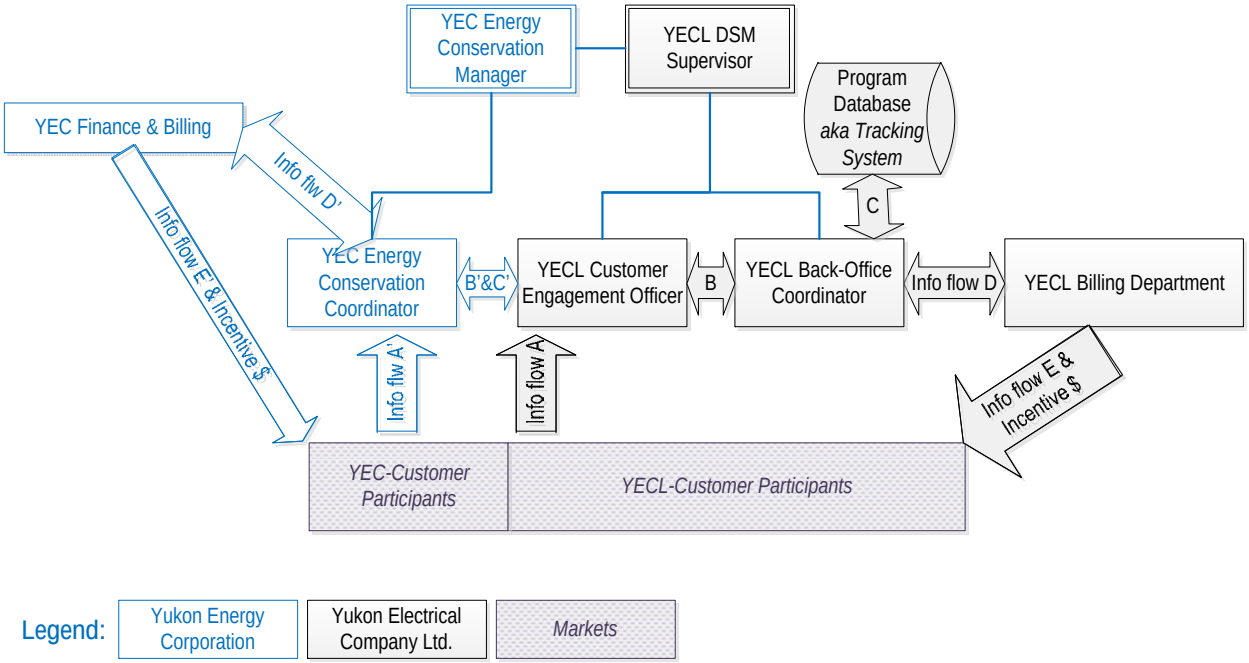
Direct Customer Engagement

C	The YECL DSM Supervisor, YECL Communications and the YECL Customer Engagement Officer will plan customer engagement events together with YEC Energy Conservation Manager.
D	The YECL Customer Engagement Officer will engage directly with YECL customers through the inCharge brand to educate them about electricity conservation, inform them about the DSM offerings and ease them into one or many of the program elements. YECL customers represent a large portion of the electricity end-user in the Yukon; hence YECL is responsible for most of the direct-engagement work. The YECL Communications Coordinator and YECL DSM Supervisor will support as needed. The YECL Customer Engagement Officer will create an Engagement Plan that – for the most part – will consist of direct engagement KPIs and targets. The YECL Customer Engagement Officer will share the engagement plan document and discuss it with the YECL DSM Supervisor to make sure that the level of activity matches expectations and will deliver sufficient uptake. The engagement plan will not include any confidential information on YECL customers. The YEC Energy Conservation Manager and YECL DSM Supervisor will jointly finalize the engagement plan The YECL Customer Engagement Officer will need to log some statistics and events to compute the KPIs thorough the year. It is more practical for YECL to keep this log separate from the main program tracking system.
E	The YEC Energy Conservation Coordinator and/or the YEC Energy Conservation Manager will engage directly with YEC customers through the inCharge brand to educate them about electricity conservation, to inform them about the DSM offerings and ease them into one or many of the program elements. It is assumed that very little engagement planning will be needed on the YEC side because much fewer electricity end-users are customers of YEC than of YECL.
F	The utilities will engage directly with other market actors through the inCharge brand to educate them on electricity conservation, to plan and execute indirect communication and education tactics, and to support them with the participation processes. It is expected that many market actors will be useful trade allies and will help promote the program.
G	There is a need for keeping records on engagement and communication activities in order to generate the KPIs that will be used to manage the program. Core utility staff will be asked to log most of engagement and communication activities, consistent with the planning and the KPIs that will be decided on.

Application Processing and Incentive Payment Information Flow

The proposed information flow for processing and incentive payment activities is presented in Exhibit 11. An explanatory note is presented in tabular format following the chart.

Exhibit 11: Application Processing and Incentive Payment Information-Flow Block Diagram



Explanation of the Information Flows – Application Processing and Incentive Payment

A	The YECL Customer Engagement Officer will engage directly with YECL customers, inform them about the offerings, ease them into one or many program elements, help them with the program applications, forms and documentation, and retrieve the paperwork from the participant. YECL customers will send in their DSM applications and forms either through YECL Customer Engagement Officer, the front-end staff or directly to the inCharge website.
B	The program applications will be passed on to the YECL Back-Office Coordinator who will process them. Processing involves[8]: checking completeness of the paperwork, checking participant and technical eligibility, checking that the forms contain the necessary signatures, in certain cases verifying the engineering calculations backing the energy savings claim, establishing the incentive amount, getting the authorization to proceed with the payment of the incentive, issuing notices to inform the participants about the status of their application, retrieving the information contained in the paperwork and input it into the tracking system, documenting the processing work into the tracking system.

[8] The process described above is scalable. For example, a small incentive application will be streamlined and involve far less steps.

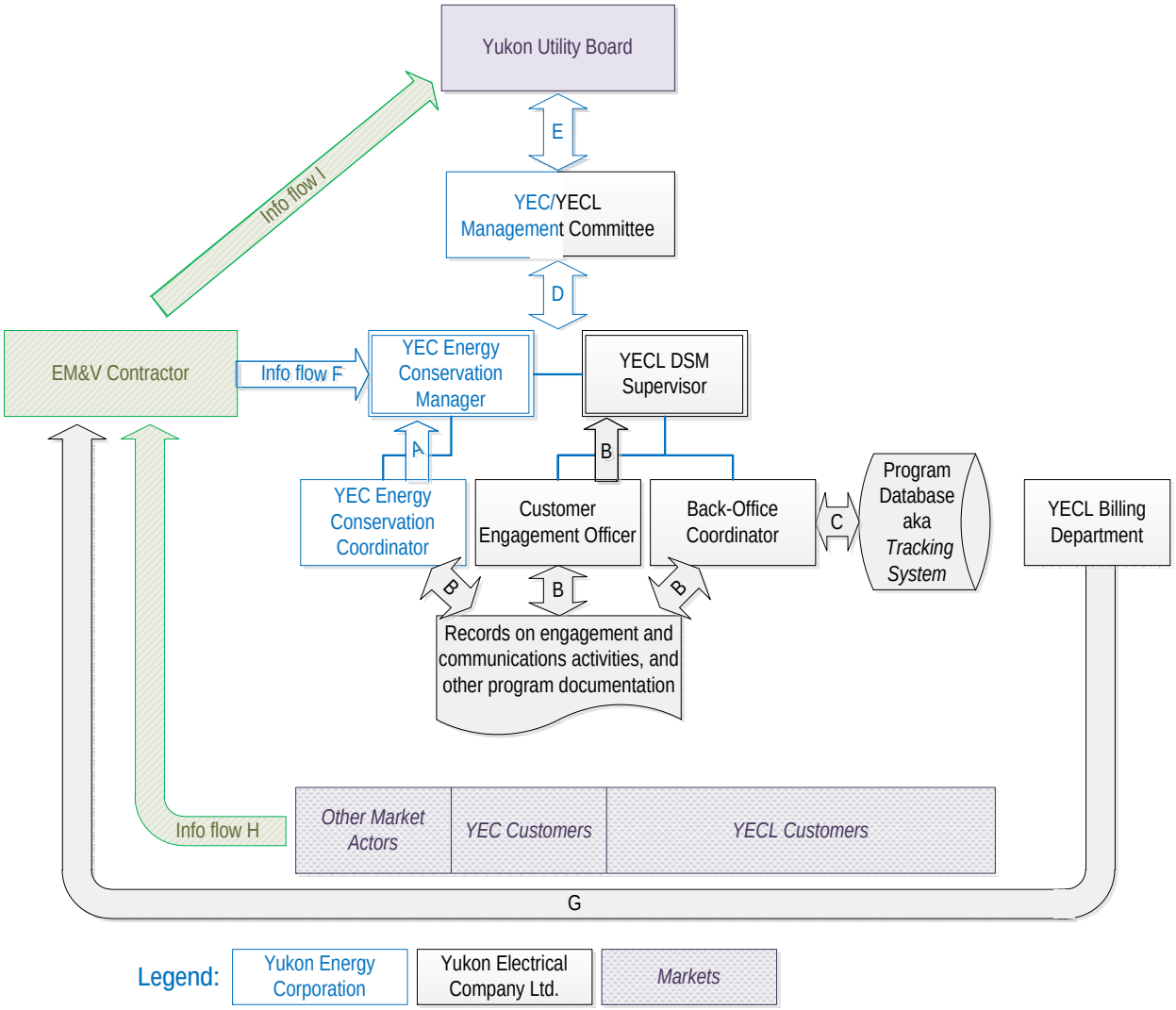
Explanation of the Information Flows – Application Processing and Incentive Payment

C	The tracking system/program database will be able to store the following data and generate reports based on it: time stamps for all transactions; participant information (names, contact information, etc.); type(s) and number of prescriptive conservation measures; description and claimed savings associated with custom conservation measures or projects; eligible savings as validated by the back-office coordinator; total measure or project cost; YECL/YEC account number and any other information used to verify participant eligibility; information used to verify technical eligibility of products or project; status of the application; claimed incentive amount; eligible incentive amount after validation; whether it is a YEC account or a YECL account; trade ally involved in the file; building or house type; how they learned about the program; and, whether the application came in directly or through YECL.
D	Whenever an incentive payment is authorized the YECL Back-Office coordinator will issue an internal form and send it to YECL Billing Department. The internal form will clearly lay out: the name of the recipient and electricity account information; the total amount of the incentive; any relevant explanatory notes – in particular if the incentive amount is not what the participant had originally claimed. The YECL Customer Engagement Officer will coordinate with the YECL Billing Department to make sure that the incentive gets paid to the recipient diligently.
E	The incentive payment can be credited on the participant energy bill or sent otherwise. It could be accompanied with an explanatory notes (mentioned in (D) if the incentive amount is not what the participant had expected. Once the payment is issued; the YECL Billing Department is expected to provide a form of feedback/confirmation to the YECL Customer Engagement Officer in order to update the database and generate the payment timestamps.
A'	The YEC Energy Conservation Coordinator will engage directly with YEC customers; ease them into one or many program elements; help them; and retrieve the paperwork from the participants. YEC customers will send in their DSM applications and forms either through YEC Energy Conservation Coordinator or directly to the inCharge website. YEC customers are much fewer than the YECL customers; therefore, it is expected that the volume of applications and the information flows described from A' to E' will be smaller.
B' & C'	The YEC Energy Conservation Coordinator will work with YECL Back-Office Coordinator to process the applications; and feed the tracking system.
D'	The YEC Energy Conservation Coordinator will work with YEC Finance to get the incentive payment made to the YEC eligible participants.
E'	YEC Finance will send incentive payments to YEC eligible participants by sending them a cheque. The YEC Energy Conservation Coordinator will work with the YECL Back-Office Coordinator to make sure that the payment status is properly inputted and time-stamped in the program database.

Performance Reporting and EM&V Information Flow

The proposed information flow for performance reporting and EM&V activities is presented in Exhibit 12. An explanatory note is presented in tabular format following the chart.

Exhibit 12: Performance Reporting and EM&V Information-Flow Block Diagram



Explanation of the Information Flows – Performance Reporting and EM&V

Performance Reporting, Planning and Budgeting

A	The YEC Energy Conservation Coordinator will extract relevant statistics, indicators, tables, and charts from the tracking system and send it to the YEC Energy Conservation Manager.
B	The YECL Customer Engagement Officer and YEC Energy Conservation Coordinator will compute the direct engagement KPIs for the quarter or year and send them to the YEC Energy Conservation Manager who will produce a combined report. All members of the inCharge team will log and keep records of communication, training and engagement activities in a format that is consistent with the KPIs that will be agreed on at the program set-up stage. Communication, training and engagement KPIs were suggested on a preliminary basis as part of the EM&V plan.

Explanation of the Information Flows – Performance Reporting and EM&V

C	The YECL Back-Office Coordinator will be responsible for inputting participation data into the tracking system with technical support from the YEC Energy Conservation Coordinator. As mentioned in (A), the YECL Back-Office Coordinator and YEC Energy Conservation Coordinator will work together to extract relevant reports from the tracking system as needed to support the management of the DSM portfolio.
D	The YEC Energy Conservation Manager will prepare a set of documents as described in Section 4.4 with the support of the YEC Energy Conservation Coordinator. They include: Annual Progress Report; Annual Work Plan; Annual Detailed Budget; and Quarterly Report. These documents are presented to the YEC/YECL Management Committee and will be reviewed, discussed and finalized.
E	The YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL Management Committee will develop an Annual Summary that will be filed with the YUB (See description in Section 4.4).

Third-Party Evaluation Measurement and Verification

F	The YEC Energy Conservation Manager will work with the YEC Energy Conservation Coordinator to make the following data and documentation available to the EM&V contractor under confidentiality terms and conditions: the program database (or extract of that database); the engagement, training and communication records and KPIs; the CPR reports; the focus paper; the market characterization reports; the program design final report; the PIP; the draft EM&V Plan; the progress reports; work plans and budgets; and all of the communication materials. The core program operation team must also be available for interviews with the EM&V contractor.
G	The YECL Billing Department will be solicited to provide billing information to the EM&V Contractor about participants and non-participant monthly electricity consumption and peak demand for 24 to 36 months before participation in the program and then 24 to 36 months after. The EM&V Contractor might have to sign a confidentiality agreement with YECL.
H	The EM&V Contractor will carry out surveys, site visits and other market research activities to gather the market intelligence needed to perform its process evaluation and impact evaluation.
I	The EM&V Contractor will file three reports with the YUB: the Final EM&V Plan; the Process Evaluation Report; and the Impact Evaluation Report. (See Section 4.4). The YEC Energy Conservation Manager, YECL DSM Supervisor and YEC/YECL management committee will be able to read early drafts of these reports, ask questions, highlight potential errors or omissions, and make comments on the reports before it is sent to the YUB.

5. Communication Plan

Section 5 provides a description of the target audiences, communication approach and goals, and key messages that will be used to strategically promote program understanding and uptake. This preliminary communication plan was designed to build on existing customer service functions and recognizes the importance of nurturing existing relationships between utilities and customers and supply-side market actors.

5.1 High-Level Communication Objectives

The high-level communication objectives are to:

1. Generate participation in the General Service and the Residential programs.
2. Raise awareness and educate Yukon residents and businesses on how adopting energy-efficient practices and equipment can save both power and money.
3. Increase YEC/YECL customer satisfaction.

To achieve the three objectives above the Utilities will seek to collaborate and develop formal or informal alliances with supply-side actors and other stakeholders to deliver information and energy efficient consumer products to the electricity end-users. The same groups may also partake in the implementation of energy efficiency projects.

5.2 Audiences

Major market actors that will need to be engaged to successfully operate the General Service and Residential programs in the Yukon include the following:

- Building owners/managers and institutional building facility managers
- Developers, architects and general contractors
- Residential customers
- Electrical distributors/independent lighting distributors
- Lighting designers
- Electrical contractors
- HVAC designers
- HVAC and control contractors
- Retailers
- External stakeholders[9]

[9] Examples: Yukon Housing Corporation, Yukon Conservation Society, the City of Whitehorse, Energy Solutions Centre, the Yukon Contractor Association, the Association of Professional Engineers of Yukon, Yukon College, and the Whitehorse Chamber of Commerce.

As shown in Exhibit 13, some of these groups will be engaged as supply-side market actors and others will be target participants for various program elements. All of these groups will be target audiences for education and engagement activities.

Exhibit 13: Audiences and Relevant Program Elements

Audience	Relevant Program Elements	Supply-Side	Participant
Building Owners/Managers and Institutional Building Facility Managers	GS Lighting Redesign and Equipment Incentive		✓
	GS High-Efficiency Refrigeration		✓
	GS Energy Star Computer Incentive		✓
Developers, Architects, Contractors	GS New Construction Incentive	✓	
	GS Lighting Redesign and Equipment Incentive		✓
	Res. LED Lighting & Automotive Heater Timer Rebates		✓
Residential Customers	Res. LED Lighting & Automotive Heater Timer Rebates		✓
	Res. Low-Cost Energy Efficient Products		✓
Electrical/lighting Distributors	GS Lighting Redesign and Equipment Incentive	✓	
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
	GS Energy Star Computer Incentive		✓
Lighting Designers	GS Lighting Redesign and Equipment Incentive	✓	
	GS Energy Star Computer Incentive		✓
Electrical Contractors	GS Lighting Redesign and Equipment Incentive	✓	
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
HVAC/Control Designers	GS New Construction Incentive	✓	
	GS Energy Star Computer Incentive		✓
HVAC/Control Contractors	GS New Construction Incentive	✓	
Retailers	GS Lighting Redesign and Equipment Incentive		✓
	GS High Efficiency Refrigeration	✓	✓
	GS Energy Star Computer Incentive	✓	✓
	Res. LED Lighting & Automotive Heater Timer Rebates	✓	
	Res. Low-Cost Energy Efficiency Products	✓	

Program communication considerations for these key players as well as internal and external stakeholders are discussed in Appendix B. Communication activities will be strongly influenced by the fact that Whitehorse is a small close-knit community where news about good or bad installations is disseminated quickly and is remembered for a long time. It is also recognized that, generally speaking, market actors prefer the direct engagement approach.

Please refer to the Market Characterization reports for more details about each of these groups.

5.3 Approach

This section presents the approach that will be employed to address the objectives of the program launch and delivery. Detailed engagement, training and communication strategies are provided in the Program Design document. Please refer to Section 3.3.6 for the General Services Program and Section 4.3.6 for the Residential Program.

Public Launch of the Program Offerings

Tactics supporting the public launch of the DSM portfolio should be integrated and planned with care. Some media tactics will be used to vehicle information on both programs, and others should be used for one or the other.

Prior to the launch the team will:

- Develop extensive web content to explain the benefits, modalities, eligibility criteria and participation process of each of the offerings.
- Prepare a detailed memo containing the same information as above for the YEC and YECL front-end staff on the new DSM portfolio. That memo should be accompanied by a formal presentation. YECL and YEC front-end staff needs to be ready to answer most questions that their customers will have after the launch.
- Design information pieces (specific type, i.e. brochures, information sheets, bill inserts, etc. to be determined once a detailed communication strategy is prepared) prior to the launch and will include similar content to that for the inCharge website.

The communications contractor will be involved in the tactics that require significant graphic design.

For the launch of the inCharge DSM portfolio (both program) the team will:

- Make a public announcement regarding the launch of inCharge. This could be done through a media release, media briefing, or other methods deemed appropriate.
- Leverage existing public relations opportunities around the expected date of launch where to go public and where to present the entire DSM portfolio.

To increase uptake of the General Service Program during the first two quarters of operation (or as required) the following tactics may be employed:

- YECL and YEC may consider sending program information to the General Service customers along with their utility bills.
- YECL Customer Engagement Officer will call upon YECL largest accounts (building owners) to offer a face to face presentation of the offerings. Similarly, YEC will arrange in-person meetings with their large customers.
- The program team will engage with General Service supply-chain actors and prospective trade allies directly to present them the program and seek to collaborate – as described below.
- The team will distribute the aforementioned information brochures to the General Service supply-chain actors for them to pass along to their customers and use them to boost their sales.
- The team will carry out joint events with interested applicable trade and commerce organization (See external stakeholders in Appendix B) – as described below.

The program team will carry out the above tactics to increase uptake of the Residential Program during the first two quarters of operation (or as required). However, the supply-chain actors and the community and non-profit organizations require additional consideration. In addition to the tactics above, the launch of the Residential Program will also include:

- The team will design and create point-of-purchase materials for the retailer to display. See details about the work to be done with retail store managers below.
- YECL Customer Engagement Officer will carry out extensive community outreach and develop an energy efficiency community network in their service areas. YEC may do the same in their service area – more about this tactic is presented below.

Once passed the first two quarters of operation, the level of intensity of the engagement, marketing and communication will decrease. However, a continuous stream of new tactics should be planned and carried out. The team may choose to re-use the tactics presented above, and also:

- General Service and Residential customers will be able to sign in the inCharge website to receive news, information and updates about the programs. With time, a database of contact information will be built and the team will be able to reach out to people who signed up through newsletter and email blasts.
- As the General Service Program unfolds, early success stories will be captured and shared (where approved by the participants) through project case studies disseminated through the website, public relation opportunities, YECL and YEC direct customer engagement, and trade/commerce events.
- Public information campaigns will be used periodically throughout the operation of the program to support continued awareness of the Residential Program offerings.

Direct Engagement with Supply-side Market Actors

During the program portfolio launch, the team will engage with the appropriate supply chain actors as listed above and described in Appendix B (Retailers are discussed in the following section). The following tactics are being envisioned:

- The program team will provide technical support on the use of the standardized incentive calculation tool and the program forms and procedures.
- Direct engagement will be used (including emails, phone calls and in-person meetings) and hard-to reach contractors will be engaged through health and safety training from the Utilities and through collaboration with distributors.
- Hands-on training will be offered on advanced electricity efficiency lighting design and on the business aspects of electricity efficiency.
- Upon request from the local supply-side market actors the Utilities will act as a broker to procure technical expertise from highly specialized lighting and HVAC experts recruited from throughout North America.
- The supply-side market actors will be able to consult with these experts to work on specific projects and improve their design skills and professional competencies.

Supply-side market actors are also encouraged to participate in program offerings where eligible. Improving the energy efficiency of supply-side market actors' homes and offices allows them to share valuable personal success stories.

Direct Engagement with Retailers

The program team will develop partnerships with retail store managers to work with them to:

- Add low-cost energy efficient items to their shelves if they haven't already.

- Identify certain models that yield higher customer satisfaction and thus provide an incentive to increase shelf space for these models.
- Install point-of-purchase materials (Education on Low-Cost EE Product).
- Share EE product sales data (in units, and on a confidential basis) to monitor the impact of the program.

Large retailers will also be engaged as key participants in the suite of General Service program offerings as retail stores are energy intensive. Installations at large retail facilities would provide high-profile examples of successful program participation.

Direct Engagement with Major Building Owners/Managers

The YECL Customer Engagement Officer will offer personalized support to building owners/managers perhaps with the support of the Back-Office Coordinator and/or Expert Consultants. YEC will offer similar support for its customers. The owners/managers are the prospective participants in all General Service program components; thus, engaging them is critical to the success of the program. The Utilities intend to use the following tactics to engage them:

- Customized support to plan investment in assets and to identify which buildings to develop projects in.
- Customized support to optimize decisions on implementation and procurement approaches.
- Support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).

Direct Engagement with Residential Customer and Creation of a Community Network

The YECL Customer Engagement Officer and YEC will engage individuals who are interested in energy conservation and are leaders among their peers to eventually join the community network.

At the start of the program operation the engagement officer will meet them at community events, at in-store events, workshops, and any opportunity for direct engagement. It is expected that distributing low-cost EE products free of charge will be a draw to initiate and build relationships with prospective EE ambassadors as well as an opportunity to demonstrate the products to their friends and relatives.

The Utilities will leverage the energy efficiency community to:

- Provide information to the communities on the low-cost EE products in a direct fashion.
- Disseminate educational and informational materials on low-cost EE products.
- Test certain low-cost products and gather customer satisfaction feedback.
- Extend the advertisement on the low-cost EE products through word-of-mouth marketing.

Training for Supply-Side Actors

The Utilities intend to provide technical support in the form of hands-on training where needed. The main training offerings that have been identified include:

- Program forms and procedures for Lighting Supply Channels.
- Program forms and procedures for HVAC and New-Construction Supply Channels.
- Electricity efficiency lighting design.
- Business aspect of electricity efficiency, including: energy audits; business cases; energy performance contracting; and energy efficiency financing.

It is expected that the knowledge provided to the supply-side actors will be passed on to many of their clients. Thus, the training should in turn educate Yukon residents and businesses on the benefits of energy efficiency and increase uptake in program offerings.

Events and Public Relations Opportunities

The Utilities propose to sponsor and attend trade shows and other events that gather local building owners/managers and/or supply-chain actors. Initially, the utilities will support existing trade events that have to do with lighting design or advanced HVAC design.

The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories and share their lessons learned. Practitioners should be able to network within the Yukon and also with manufacturer reps and agents from outside the Yukon. The Utilities will also use the trade events to advertise the DSM portfolio.

To support the events, the Utilities envision using one or several of the following tactics:

- Small grants to support the logistics of the events.
- Attendance and presentation of content at the events, such as case studies, information on program offerings, etc.
- Dissemination of information about the events through other media used by the Utilities (email blast, newsletter, website content, direct engagement, etc.).
- Support for well-known experts in the lighting or HVAC field to come to the Yukon (perhaps representatives from the IES or from ASHRAE) in the form of an allocation to pay for transportation and accommodations.
- Engagement with manufacturer reps or agents in Northern BC and Northern Alberta with the intention of convincing them to attend the events. (For example, the Utilities could invite reps from OSRAM/Sylvania, GE, Philips, Canlite, Lithonia, Cooper, Mitsubishi, Honeywell, Siemens, Johnson Controls, Lennox, etc.).

With time and if early initiatives are successful, the Utilities will explore the possibility of financing and organizing an annual stand-alone trade event in Whitehorse.

6. Financial Plan

Section 6 provides a summary of the operational budget, together with a concise description of the main cash flows between the utilities and the ratepayers as well as between utilities.

6.1 Budget

The budget shown in Exhibit 14 has been organized using the breakdown structure (BBS) that is identical to the WPS presented in Section 2.2. We recommend basing the DSM finance tracking on this BBS and assigning the program staff time and expenses (including delivery and EM&V contractors) to one of the cost categories shown previously in Exhibit 2.

Exhibit 14 Portfolio Budget Including Government Buildings

Budget Breakdown Structure	Year-1 Quarterly Budget ($1,000s)				5-Year Annual Budget Projections ($1,000s)					
	Y1-Q1	Y1-Q2	Y1-Q3	Y1-Q4	Year 1	Year 2	Year 3	Year 4	Year 5	TOTAL
GRAND TOTAL	$140	$258	$234	$193	$824	$1,240	$1,393	$1,266	$1,480	$6,203
WP1 General Service Program	$62	$129	$122	$82	$395	$628	$928	$765	$796	$3,512
WP1.1 Program Management	$15	$19	$26	$27	$88	$80	$79	$82	$84	$413
WP1.2 Engagement, Training and Communication	$12	$64	$58	$39	$174	$240	$229	$174	$179	$996
WP1.3 Lighting Redesign Study & Equipm't Incentive	$14	$18	$17	$4	$53	$150	$328	$367	$337	$1,235
WP1.3.1 Time & Materials	*$14*	*$18*	*$14*	*$1*	*$47*	*$15*	*$35*	*$40*	*$38*	*$174*
WP1.3.2 Incentive Disbursement	*$0*	*$0*	*$3*	*$3*	*$6*	*$135*	*$294*	*$327*	*$299*	*$1,062*
WP1.4 Energy Star Computer Incentive	$7	$9	$7	$12	$35	$76	$125	$0	$0	$236
WP1.4.1 Time & Materials	*$7*	*$9*	*$7*	*$6*	*$29*	*$40*	*$68*	*$0*	*$0*	*$137*
WP1.4.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$6*	*$6*	*$35*	*$57*	*$0*	*$0*	*$98*
WP1.5 High-Efficiency Refrigeration	$7	$9	$7	$0	$23	$77	$139	$74	$147	$460
WP1.5.1 Time & Materials	*$7*	*$9*	*$7*	*$0*	*$23*	*$77*	*$7*	*$74*	*$15*	*$197*
WP1.5.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$0*	*$0*	*$0*	*$132*	*$0*	*$132*	*$263*
WP1.6 New Construction Incentive	$7	$9	$7	$0	$23	$6	$27	$68	$49	$173
WP1.6.1 Time & Materials	*$7*	*$9*	*$7*	*$0*	*$23*	*$0*	*$2*	*$28*	*$4*	*$58*
WP1.6.2 Incentive Disbursement	*$0*	*$0*	*$0*	*$0*	*$0*	*$6*	*$25*	*$39*	*$45*	*$115*
WP2 Residential Program	$78	$129	$111	$111	$429	$468	$465	$501	$430	$2,294
WP2.1 Program Management	$32	$33	$18	$21	$104	$74	$66	$75	$77	$396
WP2.2 Engagement, Education and Communication	$23	$30	$30	$30	$113	$130	$134	$138	$142	$657
WP2.3 LED Lighting & Auto. Heater Timer Rebates	$17	$17	$7	$9	$51	$77	$79	$80	$81	$367
WP2.3.1 Time & Materials	*$17*	*$17*	*$2*	*$3*	*$39*	*$26*	*$27*	*$28*	*$29*	*$150*
WP2.3.2 Incentive Disbursement	*$0*	*$0*	*$5*	*$7*	*$12*	*$51*	*$52*	*$52*	*$52*	*$217*
WP2.4 Promotion of Low-Cost EE Products	$6	$49	$47	$46	$148	$157	$155	$152	$104	$715
WP2.4.1 Time & Materials	*$6*	*$44*	*$38*	*$26*	*$114*	*$109*	*$112*	*$115*	*$74*	*$523*
WP2.4.2 Incentive Disbursement	*$0*	*$5*	*$9*	*$20*	*$34*	*$48*	*$43*	*$36*	*$30*	*$192*
WP2.5 Innovative Heating Systems Initiative	$0	$0	$9	$4	$14	$31	$32	$56	$26	$159
WP2.5.1 Time & Materials	*$0*	*$0*	*$4*	*$4*	*$9*	*$22*	*$23*	*$33*	*$8*	*$94*
WP2.5.2 Incentive Disbursement	*$0*	*$0*	*$5*	*$0*	*$5*	*$9*	*$9*	*$24*	*$19*	*$65*
WP3 Evaluation, Measurement and Verification	$0	$0	$0	$0	$0	$144	$0	$0	$253	$397

6.2 Cash Flows and Payment Schemes

Four DSM cash flows are anticipated:

1. **The administration cost paid for by YEC –** Two FTEs that are members of the core staff; some direct expenses; and most of the contractor fees.
2. **The incentives paid by YEC to YEC customers –** This is expected to be a small fraction of the incentive disbursements.
3. **The administration cost paid for by YECL –** Two FTEs as members of the core staff; one corporate FTE and some direct costs.

4. **The incentives paid by YECL to YECL customers –** This is expected to be most of the incentive payment.

Incentives and costs will be reconciled between the two utilities on a quarterly basis

YEC DSM costs (administration and incentive) are going to be funded by the ratepayers because the cost will be presented to the YUB as part of the rate filing. This is going to be further defined by the outcome of the Joint Panel on DSM as part of the YECLs next general rate application.

YECL DSM costs (administration and incentive) are going to be funded by the ratepayers because the cost will be presented to the YUB as part of the rate filing. This will also be defined by the outcome of the Joint Panel on DSM as part of the YECLs next general rate application.

Appendices

Appendix A: Year-1 Detailed Action Plan

Please see attached – DSM Program Detailed Action Plan PDF

Appendix B: Audience Descriptions

Major market actors that will need to be engaged to successfully operate the General Service and Residential programs in the Yukon include the following:

- Building owners/managers and institutional building facility managers
- Developers, architects and general contractors
- Residential customers
- Electrical distributors/independent lighting distributors
- Lighting designers
- Electrical contractors
- HVAC designers
- HVAC and control contractors
- Retailers

Program communication considerations for these key players, as well as internal and external stakeholders, are discussed below.

Building Owners/Managers and Institutional Building Facility Managers

Commercial building owners/managers and institutional building managers will be targeted as major potential participants for the General Services program offerings. There are 8 large property managers/owners in the Yukon, located predominantly within Whitehorse. Building owners and managers, looking to better understand how to manage their energy bills, could find it fairly puzzling given that they work with various contractors that each has a vested interest. Owners/managers would have a higher level of trust in a third party such as the Utilities than in a supplier, so direct communication from the Utilities may be better received.

Commercial building owners/managers often have more freedom to make purchasing decisions than government building managers. Government facility managers must work within a budget decided by Council or the Territory and must follow the procurement policies. It is important to communicate the business case for program participation not only to facility managers but to City Council and other decision makers.

Building Developers, General Contractors and Architects

Developers and architects are already working in a market interested in buying environmentally-friendly homes. Words such as SuperGreen, electricity efficiency, energy conservation and ENERGY STAR are commonly used in sales pitches and collateral materials.

There are roughly 5-10 housing developers in the Yukon and developers, general contractors and architects are extremely busy. Direct and efficient communication is important with this group.

Residential Customers

Eligible participants for the Residential program include: owners of detached houses; town/row houses; condominium units; and mobiles homes located in the Yukon who shop in Yukon retail stores. The program also includes online shoppers, landlords and renters. This is a group of approximately 20,000 shoppers. The primary source of information used to make purchase decisions is the store where the purchase is made. In-store marketing material should be clear and prominent. Other key sources of information for shoppers are friends and relatives as well as websites displaying user-generated content.

The relationship between landlords and tenants was discussed in Section 4.1.4 of the Program Design report. Given the significant split-incentive barrier between landlords and tenants this segment will not be main focus for engagement.

Some individuals are particularly passionate about or interested in improving the energy efficiency of their home. These individuals will likely be interested in developing a collaborative relationship with the Utilities.

Electrical Distributors

There are only two electrical distributors in the Yukon: EECOL and Guillevin, as well as a few independent lighting distributors selling to the Yukon residential and building sectors. These distributors are key market actors. Electrical distributors often maintain relationships with a variety of market actors situated both upstream and downstream in the supply chain including: lighting designers; building owners; electrical contractors and manufacturer agents and representatives. Electrical distributors are keen to participate in programs and are easier to engage than electrical contractors because new incremental projects mean increased sales.

Lighting Designers

Only two firms offer lighting design services by professional electrical engineers. These will be very important partners for the Lighting Redesign Incentive program offerings. These designers prefer direct engagement through email, phone calls, and in-person meetings.

Electrical Contractors

Electrical contractors active in the territory are smaller regional firms with a handful of employees. There are approximately 26 electrical contractors in the Yukon and they are a hard-to-reach group of people as they are very busy and are on the road much of the time.

Depending on the type of project, electrical contractors may have a contractual relationship with a general contractor or directly with the building owner. Unless their clients are very specific about the fixtures and lamps that they want, contractors have a great deal of influence on design choices. Electrical contractors make quick and conservative design decisions based on equipment they are accustomed to. There is an opportunity to make energy efficiency design decisions easier for them by providing simple and concise educational material with a suggested prescriptive approach; and/or to provide compensation if they need to spend more time making better design decisions.

HVAC and Control Designers

There are two firms offering HVAC/control design services in the Yukon, with design teams lead by senior mechanical engineers. Designers are facing a high demand for their services. Designers are the market actors most likely to be in a position to educate the end users about the lifecycle cost benefits of energy efficient designs. However, with very little competition and a large amount of new construction projects there is little incentive for them to proactively offer innovative and efficient designs. HVAC and Control designers prefer direct engagement and would be interested in trade shows or events if they saw value in terms of learning and networking opportunities.

HVAC and Control Contractors

For the most part control systems and HVAC equipment are sold locally by contractors. There are roughly 16 HVAC/control contractors serving the Yukon. Control contractors in the Yukon are smaller local firms with a handful of employees. The two control contractors in the Yukon consist of a Honeywell dealer and a Siemens dealer. Controls contractors have long-term

maintenance contracts therefore they have significant direct interactions with owners. This provides an opportunity to educate the energy end-users.

Retailers

Retail store managers are both target program participants for the General Services program and target supply-side market actors for the Residential program (and in some cases the General Services program). Most retail stores are concentrated in Whitehorse and consist of large "big-box" retail stores as well as smaller independent stores. Store managers are more knowledgeable about DSM programs in other jurisdictions than other actors because they often have branches in other parts of Canada and the United States. They are keen to participate in joint initiatives with the utilities but are dealing with a human resource shortage.

Internal Stakeholders

All YEC/YECL staff will need to be aware of the DSM portfolio to support program communication.

External Stakeholders

External stakeholders are other organizations and individuals in the Territory that may play a role (intentionally or unintentionally) in promoting or injuring the DSM program portfolio. The key stakeholders include: the Yukon Housing Corporation; the City of Whitehorse; Energy Solutions Centre; the Yukon Contractor Association; the Association of Professional Engineers of Yukon; Yukon College; and the Whitehorse Chamber of Commerce.

The City of Whitehorse is a very sustainability and conservation minded organization (including energy) and has been involved in CPR workshops and YEC's energy planning charrettes. The General Services and Residential programs would benefit from ongoing engagement with the City on a number of fronts including: as a program participant and advocate; and as an informant of any building Bylaw changes that would affect commercial developments.

The Energy Solutions Centre (ESC) is a branch of the Yukon Government's Department of Energy, Mines and Resources. ESC participates in the design of energy policies and delivers energy programs and projects for Yukon citizens, other government departments, First Nations, municipalities and businesses. The YEC/YECL DSM portfolio has been designed to minimize duplication and potential customer confusion. This will remain an ongoing consideration.

Among other programs and services, Yukon Housing is the delivery agent for the EcoEnergy Program through the federal Office of Energy Efficiency. They also manage the Green and SuperGreen endorsement label for new residential construction energy performance. Yukon Housing also delivers a variety of training courses for residential developers and construction contractors. As for the ESC, the YEC/YECL DSM portfolio was designed to avoid duplication but it will remain an ongoing consideration.

The Yukon Contractor Association's primary objective is the overall improvement of the industry and the provision of services to their members. The Association is credible among contractors and provides several communication channels with members (who are generally difficult to reach).

The Association of Professional Engineers of Yukon (APEY) is a non-profit trade association representing professional engineers. APEY has very limited resources and did not show a high degree of interest in being an active stakeholder in YEC/YECL DSM portfolio. It may be valuable to keep the APEY aware of program activities as growth in Yukon Engineers' knowledge of energy efficiency is beneficial to the program.

Yukon College is the only post-secondary provider in the Yukon. Although the College has limited resources, it may be valuable to engage the College in the training aspect of the General Services and Residential program offerings and as a program participant.

The Whitehorse Chamber of Commerce is a local organization of businesses whose goal is to further the interests of businesses. The Chamber organizes many events, which could be used to advertise the General Services program offerings to their members and provide a forum for energy efficiency education and discussion.

CW-YECL-28

Reference: Capital Expenditures, YECL Application, Schedule 9.1

In Schedule 9.1, YECL provides forecast capital expenditures for generation. Historic actuals range from a low of $779,000 in 2009 to a high of $3,115,000 in 2012. The forecasts for 2013, 2014, and 2015 are $6,696,000, $7,759,000, and $5,900,000 respectively. The City requires an understanding of the ability of YECL to complete this aggressive schedule of construction.

Request:

(a) For each generation project forecast for 2013, please provide an update of the status of spending as of June 30. Also, please indicate if YECL has updated any of its forecasts of 2013 spending.

(b) For each year, please indicate which generation projects YECL would defer if there is a constraint on resources, and YECL cannot complete all generation projects.

Response:

(a) Yukon Electrical's Application is based on the best information available at the time of the filing, which did not include partial year actuals for 2013. Partial year results are not reflective of full year performance.

Yukon Electrical is on track to complete its forecasted 2013 generation capital.

(b) Yukon Electrical is not forecasting a constraint on resources and fully expects to complete all of the proposed generation projects in the test period.

CW-YECL-29

Reference: Capital Expenditures – Business Cases, YECL Application, Business Cases

YECL has proposed the replacement of a number of diesel generators.

Request:

(a) Please provide an inventory of diesel generators, with the age of each, the year each was installed, and the year forecast to be replaced in the test period.

Response:

(a) Please refer to the table below for the age, year of installation and year forecast to be replaced for Yukon Electrical's inventory of diesel generators:

CUL #	Location	Unit #	Engine Date of Manufacture	Year Installed	Expected Retirement Date
303	Beaver Creek	1	1988	1988	2014
378	Beaver Creek	2	1993	1993	2013
354	Beaver Creek	3	1991	1991	>10 Years
467	Destruction Bay	1	1997	1997	>10 Years
372	Destruction Bay	2	1992	1992	2015
230	Destruction Bay	3	1993	1993	2014
414	Old Crow	1	1998	1998	>10 Years
355	Old Crow	2	1991	1991	2016
384	Old Crow	3	1992	1992	2015
422	Watson Lake	1	1998	1998	2022
257	Watson Lake	2	1985	1985	2015
352	Watson Lake	3	1991	1991	2021
258	Watson Lake	4	1985	1985	2013
466	Watson Lake	5	1993	1993	>10 Years
423	Watson Lake	6	1998	1998	2019
460	Swift River	1	2010	2010	2020
413	Swift River	2	2003	2003	2013
375	Pelly Crossing	1	1992	1992	>10 Years
470	Pelly Crossing	2	1995	2011	>10 Years
405	Pelly Crossing	3	1999	1999	>10 Years
310	Carmacks	1	1991	1991	>10 Years
265	Ross River	1	1985	1989	>10 Years
416	Haines Junction	1	1992	1997	>10 Years
376	Teslin	1	1989	1993	>10 Years
186	Stewart Crossing	3	1974	1974	>10 Years

CW-YECL-30

Reference: Depreciation, YECL Application, page 7-1

On lines 15-17, YECL indicates that it has requested reinstatement of a provision for future removal and site restoration in depreciation rates. The City requires information to understand the impact of the change.

Request:

(a) Please provide Schedules 7.1 through 7.5 with the impact of the reinstatement of future removal and site restoration in depreciation rates removed.

(b) Please confirm that there are no adjustments to reserve differences to catch up on uncollected provisions for future removal and site restoration. If not confirmed, please provide an analysis summarizing the impact of changes to reserve differences for 2013-2015.

Response:

(a) Please refer to CW-YECL-30(a) Attachment 1.

(b) Not confirmed. Schedule 2B of the Gannett Fleming report provides a calculation of the true-up of accumulated depreciation variances between the Calculated Accumulated Depreciation and the Booked Accumulated Depreciation related to net salvage as of December 31, 2011. It is noted that the Accumulated Depreciation variance as determined in this depreciation study has grown substantially since the time when a similar calculation was made in the 2008 depreciation study. Gannett Fleming notes that this growth in variance is in large part caused by the suspension of collection of net salvage over the period since 2008. Given that no provision for salvage has been collected since 2008, the amount of the true-up request as indicated in Schedule 2B is the result of a number of factors including (in large part) the suspension of the collection of net salvage since 2008.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.1 - Depreciation Expense Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1	General Provision	S. 7.2, 7.3,7.4 L.51	3,585	3,892	4,108	4,559	4,641	5,081	5,901	6,743	3,760	4,067
2	Amortization of Differences	S.7.5 L. 51	(382)	(382)	(382)	(382)	(382)	(402)	(402)	(402)	(382)	(382)
3	Vehicle Depreciation Capitalized	S.8.6 L. 21	(22)	(64)	(43)	(48)	(67)	(75)	(82)	(87)	(24)	(24)
4	Total Depreciation Expense	S.1.1 L.12	3,181	3,446	3,683	4,129	4,192	4,604	5,417	6,254	3,354	3,661

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.2 - 2013 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2013 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2013 Total Depreciation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		263	2.18%	6	180	2	8
4	423 00	Hydro Resv, Dams & Waterways		2,375	2.18%	52	1,627	18	70
5	425 00	Hydro Generators		2,676	2.44%	65	1,833	22	87
6	426 00	Hydro Accessory Electrical Equip		158	2.34%	4	108	1	5
7	427 00	Hydro Misc Equip		69	3.70%	3	47	1	4
8		Total Production - Hydro		5,539		130	3,794	44	174
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,238	2.79%	63	491	7	70
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	3.08%	97	688	11	108
13	445 00	Generating Equipment & Prime Mover - Other		7,270	3.86%	280	1,594	31	311
14	446 00	Accessory Electric Equipment - Other		2,077	3.32%	69	455	8	77
15	447 00	Misc. Power Plant Equipment - Other		794	2.92%	23	174	3	26
16		Total Production - Diesel		15,517		532	3,402	60	592
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.05%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,331	1.51%	20	102	1	21
24	473 00	Poles, Towers & Fixtures		34,533	2.40%	830	2,559	31	861
25	474 00	Overhead Conductor		22,282	2.31%	515	1,703	20	535
26	474 10	Services - Overhead		2,979	2.34%	70	228	3	73
27	475 00	Underground Conductor		22,880	2.41%	550	1,732	21	571
28	475 10	Services - Underground		3,097	2.61%	81	237	3	84
29	476 10	Meters		1,984	7.65%	152	542	-	152
30	476 30	AMR - Meters		68	7.31%	5	-	-	5
31	477 10	Substation Equipment		3,131	2.50%	78	239	3	81
32	478 10	Street Lighting		9,600	3.43%	329	396	7	336
33	478 20	Sentinel Lights		285	2.99%	9	-	-	9
34	479 10	Line Transformers		28,058	2.42%	678	2,032	25	703
35		Total Distribution Plant		130,227		3,317	9,770	114	3,431
36									
37		General Plant							
38	482 00	Structures & Improvements		3,634	2.63%	96	1,124	15	111
39	483 00	Office Furniture & Equipment		194	5.70%	11	11	-	11
40	483 20	Computer Equipment		47	18.73%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		2,954	8.59%	254	432	19	273
42	485 00	Tool & Work Equipment		843	6.33%	53	86	3	56
43	486 00	Communication Structures & Equipment		938	5.50%	52	65	2	54
44	488 20	Company Housing		475	2.66%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,251	4.00%	-	650	26	26
47	493 00	Demand Side Management		-	10.00%	-	481	48	48
48	496 00	Software		2,204	10.00%	220	705	35	255
49		Total General Plant		12,541		708	3,555	148	856
50									
51		Plant Studied		165,208		4,715	20,522	366	5,081
52		Plant Not Studied - Land		380					
53		Total Plant	S.8.6 L.10	165,588					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.3 - 2014 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2014 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2014 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		442	2.53%	11	157	2	13
4	423 00	Hydro Resv, Dams & Waterways		4,001	2.36%	95	1,421	17	112
5	425 00	Hydro Generators		4,508	2.52%	114	1,601	20	134
6	426 00	Hydro Accessory Electrical Equip		266	2.60%	7	94	1	8
7	427 00	Hydro Misc Equip		116	4.06%	5	41	1	6
8		Total Production - Hydro		9,334		232	3,315	41	273
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,729	2.84%	78	649	9	87
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,826	3.17%	121	910	14	135
13	445 00	Generating Equipment & Prime Mover - Other		8,865	3.94%	349	2,109	42	391
14	446 00	Accessory Electric Equipment - Other		2,532	3.52%	89	602	11	100
15	447 00	Misc. Power Plant Equipment - Other		968	2.96%	29	230	3	32
16		Total Production - Diesel		18,919		666	4,501	79	745
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.04%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,432	1.50%	21	113	1	22
24	473 00	Poles, Towers & Fixtures		37,092	2.40%	890	2,844	34	924
25	474 00	Overhead Conductor		23,985	2.31%	554	1,887	22	576
26	474 10	Services - Overhead		3,206	2.34%	75	252	3	78
27	475 00	Underground Conductor		24,612	2.40%	592	1,921	23	615
28	475 10	Services - Underground		3,334	2.60%	87	262	3	90
29	476 10	Meters		2,525	8.09%	204	(377)	-	204
30	476 30	AMR - Meters		68	7.13%	5	1,580	56	61
31	477 10	Substation Equipment		3,370	2.50%	84	265	3	87
32	478 10	Street Lighting		9,996	3.41%	341	945	16	357
33	478 20	Sentinel Lights		285	2.93%	8	-	-	8
34	479 10	Line Transformers		30,090	2.41%	726	2,364	29	755
35		Total Distribution Plant		139,997		3,587	12,057	190	3,777
36									
37		General Plant							
38	482 00	Structures & Improvements		4,758	2.67%	127	315	4	131
39	483 00	Office Furniture & Equipment		205	6.67%	14	9	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		3,386	8.79%	298	868	38	336
42	485 00	Tool & Work Equipment		930	6.67%	62	137	5	67
43	486 00	Communication Structures & Equipment		1,003	6.67%	67	11	-	67
44	488 20	Company Housing		475	2.65%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		481	10.00%	48	522	26	74
48	496 00	Software		2,909	10.00%	291	7	-	291
49		Total General Plant		16,096		1,005	1,869	73	1,078
50									
51		Plant Studied		185,730		5,518	21,742	383	5,901
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	186,110					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.4 - 2015 Depreciation Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	2015 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2015 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		600	2.64%	16	-	-	16
4	423 00	Hydro Resv, Dams & Waterways		5,422	2.44%	132	-	-	132
5	425 00	Hydro Generators		6,110	2.56%	156	-	-	156
6	426 00	Hydro Accessory Electrical Equip		360	2.70%	10	-	-	10
7	427 00	Hydro Misc Equip		157	4.10%	6	-	-	6
8		Total Production - Hydro		12,649		320	-	-	320
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		3,378	2.97%	100	798	12	112
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		4,736	3.28%	155	1,118	18	173
13	445 00	Generating Equipment & Prime Mover - Other		10,973	4.26%	467	2,592	55	522
14	446 00	Accessory Electric Equipment - Other		3,134	3.86%	121	740	14	135
15	447 00	Misc. Power Plant Equipment - Other		1,198	3.06%	37	283	4	41
16		Total Production - Diesel		23,420		880	5,531	103	983
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.04%	28	-	-	28
20		Total Transmission		1,384		28	-	-	28
21									
22		Distribution Plant							
23	471 00	Land Rights		1,545	1.50%	23	109	1	24
24	473 00	Poles, Towers & Fixtures		39,937	2.40%	958	2,736	33	991
25	474 00	Overhead Conductor		25,872	2.31%	598	1,825	21	619
26	474 10	Services - Overhead		3,459	2.34%	81	244	3	84
27	475 00	Underground Conductor		26,534	2.40%	638	1,855	22	660
28	475 10	Services - Underground		3,596	2.60%	94	254	3	97
29	476 10	Meters		2,148	7.40%	159	(377)	-	159
30	476 30	AMR - Meters		1,648	8.08%	133	2,283	92	225
31	477 10	Substation Equipment		3,636	2.50%	91	256	3	94
32	478 10	Street Lighting		10,941	3.42%	374	813	14	388
33	478 20	Sentinel Lights		285	2.87%	8	-	-	8
34	479 10	Line Transformers		32,454	2.41%	782	2,277	27	809
35		Total Distribution Plant		152,054		3,939	12,274	219	4,158
36									
37		General Plant							
38	482 00	Structures & Improvements		5,073	2.66%	135	305	4	139
39	483 00	Office Furniture & Equipment		214	6.67%	14	2	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		4,254	9.31%	396	730	34	430
42	485 00	Tool & Work Equipment		1,066	6.67%	71	84	3	74
43	486 00	Communication Structures & Equipment		1,014	6.67%	68	12	-	68
44	488 20	Company Housing		475	2.63%	12	-	-	12
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		1,003	10.00%	100	730	37	137
48	496 00	Software		2,916	10.00%	292	57	3	295
49		Total General Plant		17,965		1,173	1,920	81	1,254
50									
51		Plant Studied		207,472		6,340	19,725	403	6,743
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	207,852					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.5 - Amortization of Differences Using 2013/2015 Proposed Depreciation Parameters
Remove Impact of Reinstatement of Future Removal and Site Restoration

Line No.	Acct.	Description	Cross Ref.	YFR/ Curve	Life	Net Salvage	Depn. Rates	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1		Production - Hydro												
2														
3	422 00	Hydro Structures		R2	72	-10%	3.36%	(14)	(14)	(2)	(2)	(2)	(14)	(14)
4	423 00	Hydro Resv, Dams & Waterways		R3	103	-10%	3.36%	-	-	(9)	(9)	(9)	-	-
5	425 00	Hydro Generators		R3	85	-10%	3.36%	-	-	(4)	(4)	(4)	-	-
6	426 00	Hydro Accessory Electrical Equip		R3	45	-10%	3.36%	-	-	(2)	(2)	(2)	-	-
7	427 00	Hydro Misc Equip		R2	30	-10%	3.36%	-	-	(1)	(1)	(1)	-	-
8		Total Production - Hydro						(14)	(14)	(17)	(17)	(17)	(14)	(14)
9														
10		Production - Diesel												
11	442 00	Structures and Improvements - Other		R2.5	40	-10%	2.74%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		R4	35	-20%	3.00%	(8)	(8)	(9)	(9)	(9)	(8)	(8)
13	445 00	Generating Equipment & Prime Mover - Other		R2.5	26	-10%	3.69%	(40)	(40)	18	18	18	(40)	(40)
14	446 00	Accessory Electric Equipment - Other		R3	35	0%	3.00%	(15)	(15)	(10)	(10)	(10)	(15)	(15)
15	447 00	Misc. Power Plant Equipment - Other		R3	40	0%	3.15%	(2)	(2)	(3)	(3)	(3)	(2)	(2)
16		Total Production - Diesel						(71)	(71)	(10)	(10)	(10)	(71)	(71)
17														
18		Transmission												
19	457 00	Substation Equipment		R4	50	-10%	2.55%	(3)	(3)	(7)	(7)	(7)	(3)	(3)
20		Total Transmission						(3)	(3)	(7)	(7)	(7)	(3)	(3)
21														
22		Distribution Plant												
23	471 00	Land Rights		R3	75	0%	1.52%	-	-	-	-	-	-	-
24	473 00	Poles, Towers & Fixtures		R3	45	-75%	2.67%	(75)	(75)	(75)	(75)	(75)	(75)	(75)
25	474 00	Overhead Conductor		R4	45	-80%	2.69%	(24)	(24)	(37)	(37)	(37)	(24)	(24)
26	474 10	Services - Overhead		R3	45	-10%	2.62%	(7)	(7)	(7)	(7)	(7)	(7)	(7)
27	475 00	Underground Conductor		R3	45	-50%	2.11%	(5)	(5)	14	14	14	(5)	(5)
28	475 10	Services - Underground		R4	40	-10%	2.63%	(6)	(6)	(4)	(4)	(4)	(6)	(6)
29	476 10	Meters		L0	15	0%	4.06%	-	-	60	60	60	-	-
30	476 30	AMR - Meters		R2.5	15	0%	4.54%			1	1	1		
31	477 10	Substation Equipment		R4	40	-10%	2.92%	(6)	(6)	(16)	(16)	(16)	(6)	(6)
32	478 10	Street Lighting		R3	30	-10%	4.13%	(61)	(61)	(64)	(64)	(64)	(61)	(61)
33	478 20	Sentinel Lights		R2	23	0%	3.37%	-	-	(18)	(18)	(18)	-	-
34	479 10	Line Transformers		R3	45	-10%	3.04%	(69)	(69)	(84)	(84)	(84)	(69)	(69)
35		Total Distribution Plant						(253)	(253)	(231)	(231)	(231)	(253)	(253)
36														
37		General Plant												
38	482 00	Structures & Improvements		L3	40	0%	3.19%	-	-	(15)	(15)	(15)	-	-
39	483 00	Office Furniture & Equipment		SQ	15	0%	4.49%	2	2	8	8	8	2	2
40	483.20	Computer Hardware/Software		SQ	5	0%	20.00%	-	-	6	6	6	-	-
41	484 00	Transportation & Mobile Equipment		L0	12	25%	10.82%	(51)	(51)	(73)	(73)	(73)	(51)	(51)
42	485 00	Tool & Work Equipment		SQ	15	0%	6.54%	(3)	(3)	4	4	4	(3)	(3)
43	486 00	Communication Structures & Equipment		SQ	15	0%	5.79%	11	11	4	4	4	11	11
44	488 20	Company Housing		R3	40	10%	2.47%			(72)	(72)	(72)		
45	491 00	Franchise & Consent					0.00%	-	-	-	-	-	-	-
46	492 00	Licence - Fish Lake					10.00%							
47	493 00	Demand Side Management												
48	496 00	Software		S3	10	0%	10.00%	-	-	-	-	-	-	-
49		Total General Plant						(41)	(41)	(138)	(138)	(138)	(41)	(41)
50														
51		Total Amortization of Differences	S. 7.1 L. 2					(382)	(382)	(402)	(402)	(402)	(382)	(382)

CW-YECL-31

Reference: Depreciation, YECL Application, page 7-2

Starting on line 4, YECL discusses its proposal for deferral treatment of depreciation parameters. The City requires information to understand the proposal.

Request:

(a) On line 8 of page 7-2, YECL asserts that IFRS requires it to review depreciation parameters annually. Please provide the complete pronouncement of IFRS that YECL asserts require it to review depreciation parameter annually, indicating the portions that support the YECL position.

(b) Please confirm that none of the YECL affiliates, including Northland Utilities (Yellowknife), Northland Utilities (NWT), ATCO Electric, ATCO Gas, or ATCO Pipelines, have a deferral account for depreciation parameters. If not confirmed, please fully explain.

Response:

(a) Please refer to CW-YECL-31(a) Attachment 1 for a copy of International Accounting Standard (IAS) 16 Property Plant and Equipment.

IAS16.61, which states the following, requires Yukon Electrical to review its depreciation parameters annually:

> The depreciation method applied to an asset shall be reviewed at least at each financial year-end and, if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method shall be changed to reflect the changed pattern. Such a change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

(b) Confirmed.

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INTERNATIONAL ACCOUNTING STANDARD 16 property, plant and equipment

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Objective

1 The objective of this Standard is to prescribe the accounting treatment for property, plant and equipment so that users of the financial statements can discern information about an entity's investment in its property, plant and equipment and the changes in such investment. The principal issues in accounting for property, plant and equipment are the recognition of the assets, the determination of their carrying amounts and the

depreciation charges and impairment losses to be recognised in relation to them.

Scope

2 This Standard shall be applied in accounting for property, plant and equipment except when another Standard requires or permits a different accounting treatment.

3 This Standard does not apply to:

(a) property, plant and equipment classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*;

(b) biological assets related to agricultural activity (see IAS 41 *Agriculture*);

(c) the recognition and measurement of exploration and evaluation assets (see IFRS 6 *Exploration for and Evaluation of Mineral Resources*); or

(d) mineral rights and mineral reserves such as oil, natural gas and similar non-regenerative resources.

However, this Standard applies to property, plant and equipment used to develop or maintain the assets described in (b)–(d).

4 Other Standards may require recognition of an item of property, plant and equipment based on an approach different from that in this Standard. For example, IAS 17 *Leases* requires an entity to evaluate its recognition of an item of leased property, plant and equipment on the basis of the transfer of risks and rewards. However, in such cases other aspects of the accounting treatment for these assets, including depreciation, are prescribed by this Standard.

5 An entity using the cost model for investment property in accordance with IAS 40 *Investment Property* shall use the cost model in this Standard.

Definitions

6 The following terms are used in this Standard with the meanings specified:

***Carrying amount* is the amount at which an asset is recognised after deducting any accumulated depreciation and accumulated impairment losses.**

***Cost* is the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognised in accordance with the specific requirements of other IFRSs, eg IFRS 2 *Share-based Payment*.**

***Depreciable amount* is the cost of an asset, or other amount substituted for cost, less its residual value.**

***Depreciation* is the systematic allocation of the depreciable amount of an asset over its useful life.**

***Entity-specific value* is the present value of the cash flows an entity expects to arise from the continuing use of an asset and from its disposal at the end of its useful life or expects to incur when settling a liability.**

***Fair value* is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (See IFRS 13 *Fair Value Measurement*.)**

An *impairment loss* is the amount by which the carrying amount of an asset exceeds its recoverable amount.

***Property, plant and equipment* are tangible items that:**

(a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

(b) are expected to be used during more than one period.

***Recoverable amount* is the higher of an asset's fair value less costs to sell and its value in use.**

The *residual value* of an asset is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs

of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.

***Useful life* is:**

(a) the period over which an asset is expected to be available for use by an entity; or

(b) the number of production or similar units expected to be obtained from the asset by an entity.

Recognition

7 The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if:

(a) it is probable that future economic benefits associated with the item will flow to the entity; and

(b) the cost of the item can be measured reliably.

8 Items such as spare parts, stand-by equipment and servicing equipment are recognised in accordance with this IFRS when they meet the definition of property, plant and equipment. Otherwise, such items are classified as inventory.

9 This Standard does not prescribe the unit of measure for recognition, ie what constitutes an item of property, plant and equipment. Thus, judgement is required in applying the recognition criteria to an entity's specific circumstances. It may be appropriate to aggregate individually insignificant items, such as moulds, tools and dies, and to apply the criteria to the aggregate value.

10 An entity evaluates under this recognition principle all its property, plant and equipment costs at the time they are incurred. These costs include costs incurred initially to acquire or construct an item of property, plant and equipment and costs incurred subsequently to add to, replace part of, or service it.

Initial costs

11 Items of property, plant and equipment may be acquired for safety or environmental reasons. The acquisition of such property, plant and equipment, although not directly increasing the future economic benefits of any particular existing item of property, plant and equipment, may be necessary for an entity to obtain the future economic benefits from its other assets. Such items of property, plant and equipment qualify for recognition as assets because they enable an entity to derive future economic benefits from related assets in excess of what could be derived had those items not been acquired. For example, a chemical manufacturer may install new chemical handling processes to comply with environmental requirements for the production and storage of dangerous chemicals; related plant enhancements are recognised as an asset because without them the entity is unable to manufacture and sell chemicals. However, the resulting carrying amount of such an asset and related assets is reviewed for impairment in accordance with IAS 36 *Impairment of Assets*.

Subsequent costs

12 Under the recognition principle in paragraph 7, an entity does not recognise in the carrying amount of an item of property, plant and equipment the costs of the day-to-day servicing of the item. Rather, these costs are recognised in profit or loss as incurred. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. The purpose of these expenditures is often described as for the 'repairs and maintenance' of the item of property, plant and equipment.

13 Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, a furnace may require relining after a specified number of hours of use, or aircraft interiors such as seats and galleys may require replacement several times during the life of the airframe. Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a nonrecurring replacement. Under the recognition principle in paragraph 7, an entity recognises in the carrying amount of

an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met. The carrying amount of those parts that are replaced is derecognised in accordance with the derecognition provisions of this Standard (see paragraphs 67–72).

14 A condition of continuing to operate an item of property, plant and equipment (for example, an aircraft) may be performing regular major inspections for faults regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised. This occurs regardless of whether the cost of the previous inspection was identified in the transaction in which the item was acquired or constructed. If necessary, the estimated cost of a future similar inspection may be used as an indication of what the cost of the existing inspection component was when the item was acquired or constructed.

Measurement at recognition

15 An item of property, plant and equipment that qualifies for recognition as an asset shall be measured at its cost.

Elements of cost

16 The cost of an item of property, plant and equipment comprises:

(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.

(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

17 Examples of directly attributable costs are:

(a) costs of employee benefits (as defined in IAS 19 *Employee Benefits*) arising directly from the construction or acquisition of the item of property, plant and equipment;

(b) costs of site preparation;

(c) initial delivery and handling costs;

(d) installation and assembly costs;

(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

(f) professional fees.

18 An entity applies IAS 2 *Inventories* to the costs of obligations for dismantling, removing and restoring the site on which an item is located that are incurred during a particular period as a consequence of having used the item to produce inventories during that period. The obligations for costs accounted for in accordance with IAS 2 or IAS 16 are recognised and measured in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*.

19 Examples of costs that are not costs of an item of property, plant and equipment are:

(a) costs of opening a new facility;

(b) costs of introducing a new product or service (including costs of advertising and promotional activities);

(c) costs of conducting business in a new location or with a new class of customer

(including costs of staff training); and

(d) administration and other general overhead costs.

20 Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item are not included in the carrying amount of that item. For example, the following costs are not included in the carrying amount of an item of property, plant and equipment:

(a) costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;

(b) initial operating losses, such as those incurred while demand for the item's output builds up; and

(c) costs of relocating or reorganising part or all of an entity's operations.

21 Some operations occur in connection with the construction or development of an item of property, plant and equipment, but are not necessary to bring the item to the location and condition necessary for it to be capable of operating in the manner intended by management. These incidental operations may occur before or during the construction or development activities. For example, income may be earned through using a building site as a car park until construction starts. Because incidental operations are not necessary to bring an item to the location and condition necessary for it to be capable of operating in the manner intended by management, the income and related expenses of incidental operations are recognised in profit or loss and included in their respective classifications of income and expense.

22 The cost of a self-constructed asset is determined using the same principles as for an acquired asset. If an entity makes similar assets for sale in the normal course of business, the cost of the asset is usually the same as the cost of constructing an asset for sale (see IAS 2). Therefore, any internal profits are eliminated in arriving at such costs. Similarly, the cost of abnormal amounts of wasted material, labour, or other resources incurred in self-constructing an asset is not included in the cost of the asset. IAS 23 *Borrowing Costs* establishes criteria for the recognition of interest as a component of the carrying amount of a self-constructed item of property, plant and equipment.

Measurement of cost

23 The cost of an item of property, plant and equipment is the cash price equivalent at the recognition date. If payment is deferred beyond normal credit terms, the difference between the cash price equivalent and the total payment is recognised as interest over the period of credit unless such interest is capitalised in accordance with IAS 23.

24 One or more items of property, plant and equipment may be acquired in exchange for a non-monetary asset or assets, or a combination of monetary and non-monetary assets. The following discussion refers simply to an exchange of one non-monetary asset for another, but it also applies to all exchanges described in the preceding sentence. The cost of such an item of property, plant and equipment is measured at fair value unless (a) the exchange transaction lacks commercial substance or (b) the fair value of neither the asset received nor the asset given up is reliably measurable. The acquired item is measured in this way even if an entity cannot immediately derecognise the asset given up. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up.

25 An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. An exchange transaction has commercial substance if:

(a) the configuration (risk, timing and amount) of the cash flows of the asset received differs from the configuration of the cash flows of the asset transferred; or

(b) the entity-specific value of the portion of the entity's operations affected by the

transaction changes as a result of the exchange; and

(c) the difference in (a) or (b) is significant relative to the fair value of the assets exchanged.

For the purpose of determining whether an exchange transaction has commercial substance, the entity-specific value of the portion of the entity's operations affected by the transaction shall reflect post-tax cash flows. The result of these analyses may be clear without an entity having to perform detailed calculations.

26 The fair value of an asset is reliably measurable if (a) the variability in the range of reasonable fair value measurements is not significant for that asset or (b) the probabilities of the various estimates within the range can be reasonably assessed and used when measuring fair value. If an entity is able to measure reliably the fair value of either the asset received or the asset given up, then the fair value of the asset given up is used to measure the cost of the asset received unless the fair value of the asset received is more clearly evident.

27 The cost of an item of property, plant and equipment held by a lessee under a finance lease is determined in accordance with IAS 17.

28 The carrying amount of an item of property, plant and equipment may be reduced by government grants in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*.

Measurement after recognition

29 An entity shall choose either the cost model in paragraph 30 or the revaluation model in paragraph 31 as its accounting policy and shall apply that policy to an entire class of property, plant and equipment.

Cost model

30 After recognition as an asset, an item of property, plant and equipment shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation model

31 After recognition as an asset, an item of property, plant and equipment whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. Revaluations shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period.

32–33 [Deleted]

34 The frequency of revaluations depends upon the changes in fair values of the items of property, plant and equipment being revalued. When the fair value of a revalued asset differs materially from its carrying amount, a further revaluation is required. Some items of property, plant and equipment experience significant and volatile changes in fair value, thus necessitating annual revaluation. Such frequent revaluations are unnecessary for items of property, plant and equipment with only insignificant changes in fair value. Instead, it may be necessary to revalue the item only every three or five years.

35 When an item of property, plant and equipment is revalued, any accumulated depreciation at the date of the revaluation is treated in one of the following ways:

(a) restated proportionately with the change in the gross carrying amount of the asset so that the carrying amount of the asset after revaluation equals its revalued amount. This method is often used when an asset is revalued by means of applying an index to determine its replacement cost (see IFRS 13).

(b) eliminated against the gross carrying amount of the asset and the net amount restated to the revalued amount of the asset. This method is often used for buildings.

The amount of the adjustment arising on the restatement or elimination of accumulated

depreciation forms part of the increase or decrease in carrying amount that is accounted for in accordance with paragraphs 39 and 40.

36 If an item of property, plant and equipment is revalued, the entire class of property, plant and equipment to which that asset belongs shall be revalued.

37 A class of property, plant and equipment is a grouping of assets of a similar nature and use in an entity's operations. The following are examples of separate classes:

(a) land;
(b) land and buildings;
(c) machinery;
(d) ships;
(e) aircraft;
(f) motor vehicles;
(g) furniture and fixtures; and
(h) office equipment.

38 The items within a class of property, plant and equipment are revalued simultaneously to avoid selective revaluation of assets and the reporting of amounts in the financial statements that are a mixture of costs and values as at different dates. However, a class of assets may be revalued on a rolling basis provided revaluation of the class of assets is completed within a short period and provided the revaluations are kept up to date.

39 If an asset's carrying amount is increased as a result of a revaluation, the increase shall be recognised in other comprehensive income and accumulated in equity under the heading of revaluation surplus. However, the increase shall be recognised in profit or loss to the extent that it reverses a revaluation decrease of the same asset previously recognised in profit or loss.

40 If an asset's carrying amount is decreased as a result of a revaluation, the decrease shall be recognised in profit or loss. However, the decrease shall be recognised in other comprehensive income to the extent of any credit balance existing in the revaluation surplus in respect of that asset. The decrease recognised in other comprehensive income reduces the amount accumulated in equity under the heading of revaluation surplus.

41 The revaluation surplus included in equity in respect of an item of property, plant and equipment may be transferred directly to retained earnings when the asset is derecognised. This may involve transferring the whole of the surplus when the asset is retired or disposed of. However, some of the surplus may be transferred as the asset is used by an entity. In such a case, the amount of the surplus transferred would be the difference between depreciation based on the revalued carrying amount of the asset and depreciation based on the asset's original cost. Transfers from revaluation surplus to retained earnings are not made through profit or loss.

42 The effects of taxes on income, if any, resulting from the revaluation of property, plant and equipment are recognised and disclosed in accordance with IAS 12 *Income Taxes*.

Depreciation

43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

44 An entity allocates the amount initially recognised in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part. For example, it may be appropriate to depreciate separately the airframe and engines of an aircraft, whether owned or subject to a finance lease. Similarly, if an entity acquires property, plant and equipment subject to an operating lease in which it is the lessor, it may be appropriate to depreciate separately amounts reflected in the cost of that item that are attributable to favourable or unfavourable lease terms relative to market terms.

45 A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

46 To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item. The remainder consists of the parts of the item that are individually not significant. If an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life of its parts.

47 An entity may choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item.

48 The depreciation charge for each period shall be recognised in profit or loss unless it is included in the carrying amount of another asset.

49 The depreciation charge for a period is usually recognised in profit or loss. However, sometimes, the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the depreciation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, the depreciation of manufacturing plant and equipment is included in the costs of conversion of inventories (see IAS 2). Similarly, depreciation of property, plant and equipment used for development activities may be included in the cost of an intangible asset recognised in accordance with IAS 38 *Intangible Assets*.

Depreciable amount and depreciation period

50 The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.

51 The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*.

52 Depreciation is recognised even if the fair value of the asset exceeds its carrying amount, as long as the asset's residual value does not exceed its carrying amount. Repair and maintenance of an asset do not negate the need to depreciate it.

53 The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

54 The residual value of an asset may increase to an amount equal to or greater than the asset's carrying amount. If it does, the asset's depreciation charge is zero unless and until its residual value subsequently decreases to an amount below the asset's carrying amount.

55 Depreciation of an asset begins when it is available for use, ie when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5 and the date that the asset is derecognised. Therefore, depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated. However, under usage methods of depreciation the depreciation charge can be zero while there is no production.

56 The future economic benefits embodied in an asset are consumed by an entity principally through its use. However, other factors, such as technical or commercial obsolescence and wear and tear while an asset remains idle, often result in the diminution of the economic benefits that might have been obtained from the asset. Consequently, all the following factors are considered in determining the useful life of an asset:

(a) expected usage of the asset. Usage is assessed by reference to the asset's

expected capacity or physical output.

(b) expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance programme, and the care and maintenance of the asset while idle.

(c) technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.

(d) legal or similar limits on the use of the asset, such as the expiry dates of related leases.

57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.

58 Land and buildings are separable assets and are accounted for separately, even when they are acquired together. With some exceptions, such as quarries and sites used for landfill, land has an unlimited useful life and therefore is not depreciated. Buildings have a limited useful life and therefore are depreciable assets. An increase in the value of the land on which a building stands does not affect the determination of the depreciable amount of the building.

59 If the cost of land includes the costs of site dismantlement, removal and restoration, that portion of the land asset is depreciated over the period of benefits obtained by incurring those costs. In some cases, the land itself may have a limited useful life, in which case it is depreciated in a manner that reflects the benefits to be derived from it.

Depreciation method

60 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.

61 The depreciation method applied to an asset shall be reviewed at least at each financial year-end and, if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method shall be changed to reflect the changed pattern. Such a change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

62 A variety of depreciation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the units of production method. Straight-line depreciation results in a constant charge over the useful life if the asset's residual value does not change. The diminishing balance method results in a decreasing charge over the useful life. The units of production method results in a charge based on the expected use or output. The entity selects the method that most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. That method is applied consistently from period to period unless there is a change in the expected pattern of consumption of those future economic benefits.

Impairment

63 To determine whether an item of property, plant and equipment is impaired, an entity applies IAS 36 *Impairment of Assets*. That Standard explains how an entity reviews the carrying amount of its assets, how it determines the recoverable amount of an asset, and when it recognises, or reverses the recognition of, an impairment loss.

64 [Deleted]

Compensation for impairment

65 Compensation from third parties for items of property, plant and equipment that were impaired, lost or given up shall be included in profit or loss when the compensation becomes receivable.

66 Impairments or losses of items of property, plant and equipment, related claims for or payments of compensation from third parties and any subsequent purchase or construction of replacement assets are separate economic events and are accounted for separately as follows:

(a) impairments of items of property, plant and equipment are recognised in accordance with IAS 36;

(b) derecognition of items of property, plant and equipment retired or disposed of is determined in accordance with this Standard;

(c) compensation from third parties for items of property, plant and equipment that were impaired, lost or given up is included in determining profit or loss when it becomes receivable; and

(d) the cost of items of property, plant and equipment restored, purchased or constructed as replacements is determined in accordance with this Standard.

Derecognition

67 The carrying amount of an item of property, plant and equipment shall be derecognised:

(a) on disposal; or

(b) when no future economic benefits are expected from its use or disposal.

68 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognised (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.

68A However, an entity that, in the course of its ordinary activities, routinely sells items of property, plant and equipment that it has held for rental to others shall transfer such assets to inventories at their carrying amount when they cease to be rented and become held for sale. The proceeds from the sale of such assets shall be recognised as revenue in accordance with IAS 18 *Revenue*. IFRS 5 does not apply when assets that are held for sale in the ordinary course of business are transferred to inventories.

69 The disposal of an item of property, plant and equipment may occur in a variety of ways (eg by sale, by entering into a finance lease or by donation). In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognising revenue from the sale of goods. IAS 17 applies to disposal by a sale and leaseback.

70 If, under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of a replacement for part of the item, then it derecognises the carrying amount of the replaced part regardless of whether the replaced part had been depreciated separately. If it is not practicable for an entity to determine the carrying amount of the replaced part, it may use the cost of the replacement as an indication of what the cost of the replaced part was at the time it was acquired or constructed.

71 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

72 The consideration receivable on disposal of an item of property, plant and equipment is recognised initially at its fair value. If payment for the item is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue in accordance with IAS 18 reflecting the effective yield on the receivable.

Disclosure

73 The financial statements shall disclose, for each class of property, plant and equipment:

(a) the measurement bases used for determining the gross carrying amount;

(b) the depreciation methods used;

(c) the useful lives or the depreciation rates used;

(d) the gross carrying amount and the accumulated depreciation (aggregated with accumulated impairment losses) at the beginning and end of the period; and

(e) a reconciliation of the carrying amount at the beginning and end of the period showing:

(i) additions;

(ii) assets classified as held for sale or included in a disposal group classified as held for sale in accordance with IFRS 5 and other disposals;

(iii) acquisitions through business combinations;

(iv) increases or decreases resulting from revaluations under paragraphs 31, 39 and 40 and from impairment losses recognised or reversed in other comprehensive income in accordance with IAS 36;

(v) impairment losses recognised in profit or loss in accordance with IAS 36;

(vi) impairment losses reversed in profit or loss in accordance with IAS 36;

(vii) depreciation;

(viii) the net exchange differences arising on the translation of the financial statements from the functional currency into a different presentation currency, including the translation of a foreign operation into the presentation currency of the reporting entity; and

(ix) other changes.

74 The financial statements shall also disclose:

(a) the existence and amounts of restrictions on title, and property, plant and equipment pledged as security for liabilities;

(b) the amount of expenditures recognised in the carrying amount of an item of property, plant and equipment in the course of its construction;

(c) the amount of contractual commitments for the acquisition of property, plant and equipment; and

(d) if it is not disclosed separately in the statement of comprehensive income, the amount of compensation from third parties for items of property, plant and equipment that were impaired, lost or given up that is included in profit or loss.

75 Selection of the depreciation method and estimation of the useful life of assets are matters of judgement. Therefore, disclosure of the methods adopted and the estimated useful lives or depreciation rates provides users of financial statements with information that allows them to review the policies selected by management and enables comparisons to be made with other entities. For similar reasons, it is necessary to disclose:

(a) depreciation, whether recognised in profit or loss or as a part of the cost of other assets, during a period; and

(b) accumulated depreciation at the end of the period.

76 In accordance with IAS 8 an entity discloses the nature and effect of a change in an accounting estimate that has an effect in the current period or is expected to have an effect in subsequent periods. For property, plant and equipment, such disclosure may arise from changes in estimates with respect to:

(a) residual values;

(b) the estimated costs of dismantling, removing or restoring items of property, plant and equipment;

(c) useful lives; and

(d) depreciation methods.

77 If items of property, plant and equipment are stated at revalued amounts, the following shall be disclosed in addition to the disclosures required by IFRS 13:

(a) the effective date of the revaluation;

(b) whether an independent valuer was involved;

(c) [deleted]

(d) [deleted]

(e) for each revalued class of property, plant and equipment, the carrying amount that would have been recognised had the assets been carried under the cost model; and

(f) the revaluation surplus, indicating the change for the period and any restrictions on the distribution of the balance to shareholders.

78 In accordance with IAS 36 an entity discloses information on impaired property, plant and equipment in addition to the information required by paragraph 73(e)(iv)–(vi).

79 Users of financial statements may also find the following information relevant to their needs:

(a) the carrying amount of temporarily idle property, plant and equipment;

(b) the gross carrying amount of any fully depreciated property, plant and equipment that is still in use;

(c) the carrying amount of property, plant and equipment retired from active use and not classified as held for sale in accordance with IFRS 5; and

(d) when the cost model is used, the fair value of property, plant and equipment when this is materially different from the carrying amount.

Therefore, entities are encouraged to disclose these amounts.

Transitional provisions

80 The requirements of paragraphs 24–26 regarding the initial measurement of an item of property, plant and equipment acquired in an exchange of assets transaction shall be applied prospectively only to future transactions.

Effective date

81 An entity shall apply this Standard for annual periods beginning on or after 1 January 2005. Earlier application is encouraged. If an entity applies this Standard for a period beginning before 1 January 2005, it shall disclose that fact.

81A An entity shall apply the amendments in paragraph 3 for annual periods beginning on or after 1 January 2006. If an entity applies IFRS 6 for an earlier period, those amendments shall be applied for that earlier period.

81B IAS 1 *Presentation of Financial Statements* (as revised in 2007) amended the terminology used throughout IFRSs. In addition it amended paragraphs 39, 40 and 73 (e)(iv). An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. If an entity applies IAS 1 (revised 2007) for an earlier period, the amendments shall be applied for that earlier period.

81C IFRS 3 *Business Combinations* (as revised in 2008) amended paragraph 44. An entity shall apply that amendment for annual periods beginning on or after 1 July 2009. If an entity applies IFRS 3 (revised 2008) for an earlier period, the amendment shall also be applied for that earlier period.

81D Paragraphs 6 and 69 were amended and paragraph 68A was added by *Improvements to IFRSs* issued in May 2008. An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. Earlier application is permitted. If an entity applies the amendments for an earlier period it shall disclose that fact and at the same time apply the related amendments to IAS 7 *Statement of Cash Flows*.

81E Paragraph 5 was amended by *Improvements to IFRSs* issued in May 2008. An entity shall apply that amendment prospectively for annual periods beginning on or after 1 January 2009. Earlier application is permitted if an entity also applies the amendments to paragraphs 8, 9, 22, 48, 53, 53A, 53B, 54, 57 and 85B of IAS 40 at the same time. If

an entity applies the amendment for an earlier period it shall disclose that fact.

81F IFRS 13, issued in May 2011, amended the definition of fair value in paragraph 6, amended paragraphs 26, 35 and 77 and deleted paragraphs 32 and 33. An entity shall apply those amendments when it applies IFRS 13.

81G *Annual Improvements 2009–2011 Cycle*, issued in May 2012, amended paragraph 8. An entity shall apply that amendment retrospectively in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* for annual periods beginning on or after 1 January 2013. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Withdrawal of other pronouncements

82 This Standard supersedes IAS 16 *Property, Plant and Equipment* (revised in 1998).

83 This Standard supersedes the following Interpretations:

(a) SIC-6 *Costs of Modifying Existing Software*;

(b) SIC-14 *Property, Plant and Equipment — Compensation for the Impairment or Loss of Items*; and

(c) SIC-23 *Property, Plant and Equipment — Major Inspection or Overhaul Costs*.

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CW-YECL-32

Reference: Depreciation, YECL Application, Attachment 1, page II-23.

Under Account 473.00 – Distribution Poles, Towers and Fixtures, Mr. Kennedy indicates that Distribution Poles, Towers, and Fixtures are analysed together as one group.

Request:

(a) Please fully describe the assets included as fixtures.

(b) Please confirm that, under IFRS, assets are to be grouped or componentized into groups that have similar lives. If not confirmed, please fully explain.

(c) Please provide all analysis conducted that demonstrates that each of Distribution Poles, Towers, and Fixtures have similar lives.

(d) Please provide the original cost of each of Distribution Poles, Towers, and Fixtures forecast for 2013, 2014, and 2015.

Response:

(a) Fixtures included in Account 47300 include the following:

- Anchors, head arm and other guys, including any guard, guy clamps, strain insulators, pole plates, etc.;
- Brackets;
- Crossarms and braces;
- Extension arms;
- Foundations;
- Ground Rods and Clamps;
- Guards;
- Insulator pins and suspension bolts;
- Poles steps;
- Racks complete with insulators;
- Reinforcing and stubbing;

- Settings;
- Shaving;
- Paint;
- Roofing;
- Stenciling;
- Tagging;
- Transformer racks and platforms;
- Other fixtures.

(b) Confirmed.

(c) It was determined during early discussions that the operational practices of Yukon Electrical would result in the life estimation to be very similar for Distribution Poles, Towers and Fixtures. Historically, the Poles, Towers and Fixtures account has contained the investment related to a fully dressed pole and the cost and effort associated with sub-componentizing the investment into poles and fixtures would be extensive and the cost would not warrant the reasonably expected small change in life estimates. It was noted that in most circumstances the retirement of poles also include the retirement of all fixtures attached to the poles, and furthermore, most fixtures are not retired until the pole is removed from service.

Gannett Fleming also notes that most regulated electric distribution utilities across Canada do not componentize the fixtures on a pole separately from the investment in the pole.

Yukon Electrical does not have any steel towers within its system, and only a limited number of wood towers. The expectation is that the limited number of wood towers would have a similar life characteristic as wood poles. Therefore the componentization of the limited investment in wood towers into a separate account is not warranted.

(d) As shown in Section 7, Schedules 7.2-7.4, the investment in Account 47300 is $34,533,000, $37,092,000, and $39,937,000 for 2013, 2014 and 2015 respectively. Yukon Electrical does not maintain Account 47300 to the level requested.

CW-YECL-33

Reference: Depreciation, YECL Application, page 7-1

On line 10-14, YECL states:

10 .....For this
11 depreciation study, Yukon Electrical has incorporated the usage of a life span analysis
12 (similar to hydro generation) for each of its diesel generation locations. This will allow
13 for more accurate depreciation rates for diesel generation facilities. The depreciation
14 methods and results are presented in the study.

The City requires information to understand the impact of the change.

Request:

(a) Please provide a full and complete explanation of the difference between the life span analysis and the previous depreciation method for diesel assets.

(b) Please fully explain how the life span analysis produces more accurate depreciation rates.

(c) Please provide an analysis that clearly quantifies the impact of the change on depreciation rates and expense.

Response:

(a) Please refer to the response to information request YUB-YECL-81(b).

(b) Please refer to the response to information request YUB-YECL-81(b).

(c) Please refer to CW-YECL-33 Attachments 1 and 2, being schedules of depreciation rates calculated in the same manner as Schedules 1A and 2A of the Gannett Fleming report, but with the Life Span Impacts removed. In total, the inclusion of the Life Span approach has a less than $50,000[1] impact on the depreciation expense applied to the recovery of original cost.

[1] Difference between the filed Schedules 1A and 2A (Section 7, Attachment 1, pages 53 and 56, Annual Provision for True-Ups) and Schedules 1A and 2A referenced in this information response.

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
GENERATION							
HYDRO GENERATION (LIFE SPAN OF 2052)							
422.00	HYDRO STRUCTURES	72- R2	(10)	215,286	55,887	4,066	1.89
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	(10)	1,875,073	217,466	22,936	1.22
425.00	HYDRO GENERATORS	85- R3	(10)	1,458,435	114,857	21,767	1.49
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	(10)	105,192	53,085	2,665	2.53
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	(10)	68,657	21,393	2,897	4.22
TOTAL HYDRO PLANT				**3,722,643**	**462,688**	**54,331**	
DIESEL GENERATION							
BEAVER CREEK (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,488	24,449	987	2.63
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	92,859	48,830	3,263	3.51
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	535,779	404,185	21,611	4.03
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	173,365	57,856	5,293	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	48,603	8,070	1,358	2.79
TOTAL BEAVER CREEK				**888,094**	**543,390**	**32,512**	
CARMACKS (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	167,739	48,069	5,160	3.08
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	40,394	30,085	1,395	3.45
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	419,543	340,161	16,443	3.92
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	101,158	34,682	3,102	3.07
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	7,366	526	212	2.88
TOTAL CARMACKS				**736,201**	**453,523**	**26,312**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DESTRUCTION BAY (LIFE SPAN OF 2023)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	42,282	31,410	1,054	2.49
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	105,478	48,762	3,761	3.57
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	488,076	137,467	21,760	4.46
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	284,627	110,212	8,557	3.01
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	28,048	9,297	750	2.67
TOTAL DESTRUCTION BAY				**948,512**	**337,148**	**35,882**	
HAINES JUNCTION (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	608,472	124,969	19,354	3.18
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	619,132	298,626	22,049	3.56
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	60,097	41,010	2,538	4.22
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	94,952	47,492	2,677	2.82
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	2,454	1,480	58	2.36
TOTAL HAINES JUNCTION				**1,385,107**	**513,577**	**46,676**	
OLD CROW (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	187,900	112,056	5,101	2.71
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	215,087	99,570	7,563	3.52
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	1,223,713	582,440	54,655	4.47
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	119,365	68,323	3,379	2.83
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	171,496	66,372	4,541	2.65
TOTAL OLD CROW				**1,917,561**	**928,761**	**75,239**	
PELLY CROSSING (LIFE SPAN OF 2033)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	48,892	36,350	1,234	2.52
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	129,302	109,763	3,923	3.03
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	474,056	329,947	19,657	4.15
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	431,735	151,302	13,158	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	61,485	17,984	1,668	2.71
TOTAL PELLY CROSSING				**1,145,469**	**645,346**	**39,640**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
ROSS RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	171,221	62,610	5,094	2.98
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	85,126	39,551	3,056	3.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	189,753	161,805	7,158	3.77
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	124,872	48,576	3,768	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	9,639	1,747	267	2.77
TOTAL ROSS RIVER				**580,611**	**314,289**	**19,343**	
STEWART CROSSING (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	247,966	69,787	7,636	3.08
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	65,107	17,905	2,331	3.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	45,677	27,331	1,842	4.03
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	70,425	26,610	2,126	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	84,682	6,880	2,439	2.88
TOTAL STEWART CROSSING				**513,857**	**148,513**	**16,374**	
SWIFT RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	22,503	10,866	638	2.84
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	63,430	45,174	2,194	3.46
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	241,047	108,696	10,643	4.42
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	93,560	31,048	2,877	3.08
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	11,924	3,171	326	2.73
TOTAL SWIFT RIVER				**432,465**	**198,955**	**16,678**	
TESLIN (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,986	11,428	1,205	3.17
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	99,863	27,143	3,619	3.62
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	762,034	576,875	31,182	4.09
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	54,417	25,006	1,611	2.96
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	69,778	9,088	1,966	2.82
TOTAL TESLIN				**1,024,077**	**649,540**	**39,583**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
WATSON LAKE (LIFE SPAN OF 2113)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	359,393	224,332	9,727	2.71
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	747,818	129,740	27,011	3.61
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	2,169,195	1,450,577	87,925	4.05
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	578,189	305,256	16,449	2.84
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	258,430	61,919	7,095	2.75
TOTAL WATSON LAKE				**4,113,025**	**2,171,824**	**148,207**	
TOTAL DIESEL PLANT				**13,684,978**	**6,904,866**	**496,446**	
MOBILE							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	10,662	9,690	239	2.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	25,562	20,399	868	3.40
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	568,500	333,611	23,635	4.16
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	87,652	40,799	2,555	2.91
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	92,170	12,008	2,603	2.82
TOTAL MOBILE				**784,546**	**416,507**	**29,900**	
TOTAL GENERATION				**18,192,167**	**7,784,061**	**580,677**	
SUBSTATION PLANT							
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	(10)	1,384,421	689,303	31,326	2.26
TOTAL SUBSTATION PLANT				**1,384,421**	**689,303**	**31,326**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	75- R3	0	1,267,608	151,638	19,155	1.51
473.00	POLES, TOWERS AND FIXTURES	45- R3	(75)	30,231,546	15,702,296	1,271,960	4.21
474.00	OVERHEAD CONDUCTOR	45- R4	(80)	20,514,612	10,498,681	855,625	4.17
474.10	OVERHEAD SERVICES	45- R3	(10)	2,849,453	1,125,671	73,754	2.59
475.00	UNDERGROUND CONDUIT	45- R3	(50)	20,982,589	9,111,686	759,512	3.62
475.10	UNDERGROUND SERVICES	40- R4	(10)	2,953,077	1,016,443	84,924	2.88
476.10	METERS	15- L0	0	1,683,985	682,328	134,650	8.00
476.30	AMR - METERS	15- R2.5	0	67,646	14,259	5,175	7.65
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	(10)	3,131,073	1,765,608	86,967	2.78
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	(10)	9,147,522	4,196,129	347,924	3.80
478.20	SENTINEL LIGHTS	23- R2	0	284,738	246,947	8,784	3.08
479.10	LINE TRANSFORMERS	45- R3	(10)	24,427,769	7,365,548	649,018	2.66
TOTAL DISTRIBUTION PLANT				**117,541,619**	**51,877,234**	**4,297,448**	
GENERAL PLANT							
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	0	3,459,315	1,660,879	91,701	2.65
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	0	172,793	62,511	10,448	6.05
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	0	47,367	10,448	8,929	18.85
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	25	2,561,147	964,510	157,467	6.15
485.00	TOOLS AND INSTRUMENTS	15- SQ	0	719,184	273,558	46,712	6.50
486.00	COMMUNICATION EQUIPMENT	15- SQ	0	872,842	422,551	49,726	5.70
488.20	HOUSES	40- R3	(10)	473,256	167,636	13,991	2.96
TOTAL GENERAL PLANT				**8,305,904**	**3,562,093**	**378,974**	
TOTAL UTILITY PLANT IN SERVICE				**145,424,111**	**63,912,691**	**5,288,425**	
(*) Interim Survivor Curve					47,322,767	3,941,917	
					16,589,924	1,346,508	
					63,912,691	5,288,425	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
GENERATION						
HYDRO GENERATION (LIFE SPAN REMOVED)						
422.00	HYDRO STRUCTURES	72- R2	215,286	50,806	3,696	1.72
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	1,875,073	197,696	20,851	1.11
425.00	HYDRO GENERATORS	85- R3	1,458,435	104,415	19,788	1.36
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	105,192	48,259	2,423	2.30
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	68,657	19,448	2,634	3.84
TOTAL HYDRO PLANT			**3,722,643**	**420,625**	**49,392**	
DIESEL GENERATION						
BEAVER CREEK (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	37,488	22,226	897	2.39
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	92,859	40,692	2,719	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	535,779	367,441	19,646	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	173,365	57,856	5,293	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	48,603	8,070	1,358	2.79
TOTAL BEAVER CREEK			**888,094**	**496,285**	**29,914**	
CARMACKS (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	167,739	43,699	4,691	2.80
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	40,394	25,071	1,163	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	419,543	309,237	14,948	3.56
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	101,158	34,682	3,102	3.07
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	7,366	526	212	2.88
TOTAL CARMACKS			**736,201**	**413,215**	**24,116**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
DESTRUCTION BAY (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	42,282	28,555	958	2.27
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	105,478	40,635	3,134	2.97
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	488,076	124,970	19,782	4.05
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	284,627	110,212	8,557	3.01
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	28,048	9,297	750	2.67
TOTAL DESTRUCTION BAY			**948,512**	**313,669**	**33,181**	
HAINES JUNCTION (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	608,472	113,608	17,595	2.89
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	619,132	248,855	18,374	2.97
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	60,097	37,282	2,307	3.84
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	94,952	47,492	2,677	2.82
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	2,454	1,480	58	2.36
TOTAL HAINES JUNCTION			**1,385,107**	**448,717**	**41,011**	
OLD CROW (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	187,900	101,869	4,637	2.47
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	215,087	82,975	6,303	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	1,223,713	529,491	49,686	4.06
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	119,365	68,323	3,379	2.83
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	171,496	66,372	4,541	2.65
TOTAL OLD CROW			**1,917,561**	**849,030**	**68,546**	
PELLY CROSSING (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	48,892	33,045	1,122	2.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	129,302	91,469	3,269	2.53
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	474,056	299,952	17,870	3.77
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	431,735	151,302	13,158	3.05
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	61,485	17,984	1,668	2.71
TOTAL PELLY CROSSING			**1,145,469**	**593,752**	**37,087**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
ROSS RIVER (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	171,221	56,918	4,631	2.70
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	85,126	32,959	2,547	2.99
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	189,753	147,095	6,507	3.43
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	124,872	48,576	3,768	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	9,639	1,747	267	2.77
TOTAL ROSS RIVER			**580,611**	**287,296**	**17,720**	
STEWART CROSSING (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	247,966	63,443	6,942	2.80
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	65,107	14,921	1,943	2.98
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	45,677	24,846	1,675	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	70,425	26,610	2,126	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	84,682	6,880	2,439	2.88
TOTAL STEWART CROSSING			**513,857**	**136,700**	**15,124**	
SWIFT RIVER (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	22,503	9,878	580	2.58
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	63,430	37,645	1,828	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	241,047	98,815	9,675	4.01
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	93,560	31,048	2,877	3.08
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	11,924	3,171	326	2.73
TOTAL SWIFT RIVER			**432,465**	**180,557**	**15,287**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
TESLIN (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	37,986	10,389	1,095	2.88
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	99,863	22,619	3,016	3.02
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	762,034	524,432	28,347	3.72
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	54,417	25,006	1,611	2.96
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	69,778	9,088	1,966	2.82
TOTAL TESLIN			**1,024,077**	**591,534**	**36,036**	
WATSON LAKE (LIFE SPAN REMOVED)						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	359,393	203,938	8,843	2.46
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	747,818	108,117	22,509	3.01
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	2,169,195	1,318,706	79,932	3.68
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	578,189	305,256	16,449	2.84
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	258,430	61,919	7,095	2.75
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**134,828**	
TOTAL DIESEL PLANT			**13,684,978**	**6,308,691**	**452,848**	
MOBILE						
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	10,662	8,809	217	2.04
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	25,562	16,999	723	2.83
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	568,500	303,283	21,486	3.78
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	87,652	40,799	2,555	2.91
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	92,170	12,008	2,603	2.82
TOTAL MOBILE			**784,546**	**381,898**	**27,585**	
TOTAL GENERATION			**18,192,167**	**7,111,214**	**529,825**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST OF INVESTMENT
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
SUBSTATION PLANT						
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	1,384,421	626,639	28,478	2.06
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**28,478**	
DISTRIBUTION PLANT						
471.00	LAND RIGHTS	75- R3	1,267,608	151,638	19,155	1.51
473.00	POLES, TOWERS AND FIXTURES	45- R3	30,231,546	8,972,741	726,834	2.40
474.00	OVERHEAD CONDUCTOR	45- R4	20,514,612	5,832,601	475,347	2.32
474.10	OVERHEAD SERVICES	45- R3	2,849,453	1,023,337	67,049	2.35
475.00	UNDERGROUND CONDUIT	45- R3	20,982,589	6,074,457	506,341	2.41
475.10	UNDERGROUND SERVICES	40- R4	2,953,077	924,039	77,204	2.61
476.10	METERS	15- L0	1,683,985	682,328	134,650	8.00
476.30	AMR - METERS	15- R2.5	67,646	14,259	5,175	7.65
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	3,131,073	1,605,098	79,061	2.53
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	9,147,522	3,814,663	316,295	3.46
478.20	SENTINEL LIGHTS	23- R2	284,738	246,947	8,784	3.08
479.10	LINE TRANSFORMERS	45- R3	24,427,769	6,695,953	590,016	2.42
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**3,005,911**	
GENERAL PLANT						
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	3,459,315	1,660,879	91,701	2.65
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	172,793	62,511	10,448	6.05
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	47,367	10,448	8,929	18.85
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	2,561,147	964,510	157,467	6.15
485.00	TOOLS AND INSTRUMENTS	15- SQ	719,184	273,558	46,712	6.50
486.00	COMMUNICATION EQUIPMENT	15- SQ	872,842	422,551	49,726	5.70
488.20	HOUSES	40- R3	473,256	152,396	12,719	2.69
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**377,702**	
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,322,767**	**3,941,917**	

(*) Interim Survivor Curve

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
GENERATION							
HYDRO PLANT (LIFE SPAN REMOVED)							
422.00	HYDRO STRUCTURES	72- R2	(10)	215,286	5,081	370	0.17
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103- R3	(10)	1,875,073	19,770	2,085	0.11
425.00	HYDRO GENERATORS	85- R3	(10)	1,458,435	10,442	1,979	0.14
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45- R3	(10)	105,192	4,826	242	0.23
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30- R2	(10)	68,657	1,945	263	0.38
TOTAL HYDRO PLANT				**3,722,643**	**42,063**	**4,939**	
PRODUCTION DIESEL PLANT							
BEAVER CREEK (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,488	2,223	90	0.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	92,859	8,138	544	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	535,779	36,744	1,965	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	173,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	48,603	-	-	-
TOTAL BEAVER CREEK				**888,094**	**47,105**	**2,598**	
CARMACKS (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	167,739	4,370	469	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	40,394	5,014	233	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	419,543	30,924	1,495	0.36
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	101,158	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	7,366	-	-	-
TOTAL CARMACKS				**736,201**	**40,308**	**2,196**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DESTRUCTION BAY (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	42,282	2,855	96	0.23
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	105,478	8,127	627	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	488,076	12,497	1,978	0.41
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	284,627	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	28,048	-	-	-
TOTAL DESTRUCTION BAY				**948,512**	**23,479**	**2,701**	
HAINES JUNCTION (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	608,472	11,361	1,759	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	619,132	49,771	3,675	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	60,097	3,728	231	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	94,952	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	2,454	-	-	-
TOTAL HAINES JUNCTION				**1,385,107**	**64,860**	**5,665**	
OLD CROW (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	187,900	10,187	464	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	215,087	16,595	1,261	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	1,223,713	52,949	4,969	0.41
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	119,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	171,496	-	-	-
TOTAL OLD CROW				**1,917,561**	**79,731**	**6,693**	
PELLY CROSSING (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	48,892	3,305	112	0.23
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	129,302	18,294	654	0.51
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	474,056	29,995	1,787	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	431,735	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	61,485	-	-	-
TOTAL PELLY CROSSING				**1,145,469**	**51,594**	**2,553**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
ROSS RIVER (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	171,221	5,692	463	0.27
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	85,126	6,592	509	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	189,753	14,710	651	0.34
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	124,872	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	9,639	-	-	-
TOTAL ROSS RIVER				**580,611**	**26,993**	**1,623**	
STEWART CROSSING (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	247,966	6,344	694	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	65,107	2,984	389	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	45,677	2,485	167	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	70,425	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	84,682	-	-	-
TOTAL STEWART CROSSING				**513,857**	**11,813**	**1,250**	
SWIFT RIVER (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	22,503	988	58	0.26
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	63,430	7,529	366	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	241,047	9,881	968	0.40
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	93,560	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	11,924	-	-	-
TOTAL SWIFT RIVER				**432,465**	**18,398**	**1,391**	
TESLIN(LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	37,986	1,039	110	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	99,863	4,524	603	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	762,034	52,443	2,835	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	54,417	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	69,778	-	-	-
TOTAL TESLIN				**1,024,077**	**58,006**	**3,547**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
WATSON LAKE (LIFE SPAN REMOVED)							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	359,393	20,394	884	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	747,818	21,623	4,502	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	2,169,195	131,871	7,993	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	578,189	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	258,430	-	-	-
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**13,379**	
TOTAL DIESEL PLANT				**13,684,978**	**596,175**	**43,598**	
MOBILE							
442.00	STRUCTURES AND IMPROVEMENTS	40- R2.5	(10)	10,662	881	22	0.20
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35- R4	(20)	25,562	3,400	145	0.57
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26- S2.5	(10)	568,500	30,328	2,149	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35- R3	0	87,652	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40- R3	0	92,170	-	-	-
TOTAL MOBILE				**784,546**	**34,609**	**2,315**	
TOTAL GENERATION				**18,192,167**	**672,847**	**50,852**	
SUBSTATION PLANT							
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50- R4	(10)	1,384,421	62,664	2,848	0.21
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**2,848**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	75- R3	0	1,267,608	-	-	-
473.00	POLES, TOWERS AND FIXTURES	45- R3	(75)	30,231,546	6,729,555	545,126	1.80
474.00	OVERHEAD CONDUCTOR	45- R4	(80)	20,514,612	4,666,080	380,278	1.85
474.10	OVERHEAD SERVICES	45- R3	(10)	2,849,453	102,334	6,705	0.24
475.00	UNDERGROUND CONDUIT	45- R3	(50)	20,982,589	3,037,229	253,171	1.21
475.10	UNDERGROUND SERVICES	40- R4	(10)	2,953,077	92,404	7,720	0.26
476.10	METERS	15- L0	0	1,683,985	-	-	-
476.30	AMR - METERS	15- R2.5	0	67,646	-	-	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40- R4	(10)	3,131,073	160,510	7,906	0.25
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30- R3	(10)	9,147,522	381,466	31,629	0.35
478.20	SENTINEL LIGHTS	23- R2	0	284,738	-	-	-
479.10	LINE TRANSFORMERS	45- R3	(10)	24,427,769	669,595	59,002	0.24
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**1,291,536**	
GENERAL PLANT							
482.00	STRUCTURES AND IMPROVEMENTS	40- L3	0	3,459,315	-	-	-
483.00	OFFICE FURNITURE AND EQUIPMENT	15- SQ	0	172,793	-	-	-
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5- SQ	0	47,367	-	-	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12- L0	25	2,561,147	-	-	-
485.00	TOOLS AND INSTRUMENTS	15- SQ	0	719,184	-	-	-
486.00	COMMUNICATION EQUIPMENT	15- SQ	0	872,842	-	-	-
488.20	HOUSES	40- R3	(10)	473,256	15,240	1,272	0.27
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**1,272**	
TOTAL UTILITY PLANT IN SERVICE				**145,424,111**	**16,589,924**	**1,346,508**	

(*) Interim Survivor Curve

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION									
HYDRO PLANT (LIFE SPAN REMOVED)									
422.00	HYDRO STRUCTURES	0-ND	(10)	215,286	55,887	124,005	(68,118)	64.1	(1,063)
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	(10)	1,875,073	217,466	666,411	(448,945)	97.7	(4,595)
425.00	HYDRO GENERATORS	103-R3	(10)	1,458,435	114,857	317,214	(202,357)	81.9	(2,471)
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	(10)	105,192	53,085	100,267	(47,182)	34.3	(1,376)
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	(10)	68,657	21,393	40,256	(18,863)	27.7	(681)
TOTAL HYDRO PLANT				**3,722,643**	**462,688**	**1,248,153**	**(785,465)**		**(10,185)**
PRODUCTION DIESEL PLANT									
BEAVER CREEK(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,488	24,449	23,208	1,241	19.2	65
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	92,859	48,830	51,507	(2,677)	22.0	(122)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	535,779	404,185	370,768	33,417	9.6	3,481
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	173,365	57,856	71,106	(13,250)	26.1	(508)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	48,603	8,070	11,347	(3,277)	34.9	(94)
TOTAL BEAVER CREEK				**888,094**	**543,390**	**527,936**	**15,454**		**2,822**
CARMACKS (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	167,739	48,069	46,129	1,940	31.7	61
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	40,394	30,085	31,735	(1,650)	14.4	(115)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	419,543	340,161	312,037	28,124	8.3	3,388
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	101,158	34,682	42,594	(7,912)	24.7	(320)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	7,366	526	741	(215)	39.0	(6)
TOTAL CARMACKS				**736,201**	**453,523**	**433,236**	**20,287**		**3,009**
DESTRUCTION BAY(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	42,282	31,410	32,563	(1,153)	17.2	(67)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	105,478	48,762	69,050	(20,288)	23.3	(871)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	488,076	137,467	141,304	(3,837)	21.1	(182)
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	284,627	110,212	174,968	(64,756)	27.7	(2,338)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	28,048	9,297	18,250	(8,953)	34.7	(258)
TOTAL DESTRUCTION BAY				**948,512**	**337,148**	**436,135**	**(98,987)**		**(3,715)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	608,472	124,969	120,535	4,434	34.8	127
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	619,132	298,626	315,076	(16,450)	21.9	(751)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	60,097	41,010	37,619	3,391	11.2	303
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	94,952	47,492	58,328	(10,836)	25.4	(427)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	2,454	1,480	2,053	(573)	36.5	(16)
TOTAL HAINES JUNCTION				**1,385,107**	**513,577**	**533,611**	**(20,034)**		**(763)**
OLD CROW (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	187,900	112,056	106,381	5,675	21.2	268
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	215,087	99,570	105,029	(5,459)	24.1	(227)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	1,223,713	582,440	535,342	47,098	15.7	3,000
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	119,365	68,323	83,910	(15,587)	18.9	(825)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	171,496	66,372	92,168	(25,796)	27.3	(945)
TOTAL OLD CROW				**1,917,561**	**928,761**	**922,830**	**5,931**		**1,271**
PELLY CROSSING (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	48,892	36,350	35,274	1,076	15.9	68
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	129,302	109,763	117,576	(7,813)	27.4	(285)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	474,056	329,947	302,837	27,110	10.9	2,487
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	431,735	151,302	201,570	(50,268)	25.3	(1,987)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	61,485	17,984	27,874	(9,890)	33.4	(296)
TOTAL PELLY CROSSING				**1,145,469**	**645,346**	**685,131**	**(39,785)**		**(13)**
ROSS RIVER (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	171,221	62,610	59,849	2,761	29.4	94
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	85,126	39,551	41,720	(2,169)	22.2	(98)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	189,753	161,805	148,427	13,378	7.3	1,833
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	124,872	48,576	59,658	(11,082)	23.5	(472)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	9,639	1,747	2,459	(712)	35.5	(20)
TOTAL ROSS RIVER				**580,611**	**314,289**	**312,113**	**2,176**		**1,337**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	247,966	69,787	67,028	2,759	32.0	86
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	65,107	17,905	18,651	(746)	28.6	(26)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	45,677	27,331	22,882	4,449	10.9	408
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	70,425	26,610	32,681	(6,071)	24.9	(244)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	84,682	6,880	9,677	(2,797)	38.1	(73)
TOTAL STEWART CROSSING				**513,857**	**148,513**	**150,919**	**(2,406)**		**151**
SWIFT RIVER (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	22,503	10,866	10,333	533	25.6	21
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	63,430	45,174	47,651	(2,477)	15.7	(158)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	241,047	108,696	100,060	8,636	16.3	530
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	93,560	31,048	38,140	(7,092)	25.1	(283)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	11,924	3,171	4,419	(1,248)	31.3	(40)
TOTAL SWIFT RIVER				**432,465**	**198,955**	**200,603**	**(1,648)**		**70**
TESLIN (LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,986	11,428	10,886	542	31.2	17
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	99,863	27,143	28,631	(1,488)	27.5	(54)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	762,034	576,875	529,180	47,695	9.6	4,968
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	54,417	25,006	30,711	(5,705)	21.5	(265)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	69,778	9,088	12,886	(3,798)	35.6	(107)
TOTAL TESLIN				**1,024,077**	**649,540**	**612,294**	**37,246**		**4,559**
WATSON LAKE(LIFE SPAN REMOVED)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	359,393	224,332	212,703	11,629	20.1	579
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	747,818	129,740	136,854	(7,114)	30.6	(232)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	2,169,195	1,450,577	1,329,304	121,273	11.3	10,732
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	578,189	305,256	374,897	(69,641)	22.3	(3,123)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	258,430	61,919	85,778	(23,859)	33.8	(706)
TOTAL WATSON LAKE				**4,113,025**	**2,171,824**	**2,139,535**	**32,289**		**7,249**
TOTAL PRODUCTION DIESEL PLANT				**13,684,978**	**6,904,866**	**6,954,344**	**(49,478)**	**-**	**15,979**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2.0: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

COMBINED ANALYSIS

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	10,662	9,690	9,187	503	9.3	54
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	25,562	20,399	21,517	(1,118)	12.8	(87)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	568,500	333,611	304,470	29,141	13.1	2,225
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	87,652	40,799	50,120	(9,321)	23.1	(404)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	92,170	12,008	16,636	(4,628)	35.5	(130)
TOTAL MOBILE				**784,546**	**416,507**	**401,930**	**14,577**		**1,657**
TOTAL GENERATION				**18,192,167**	**7,784,061**	**8,604,427**	**(820,366)**		**7,451**
SUBSTATION PLANT									
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	(10)	1,384,421	689,303	851,143	(161,840)	31.0	(5,221)
TOTAL SUBSTATION PLANT				1,384,421	689,303	851,143	(161,840)		(5,221)
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	0	0	1,267,608	151,638	151,342	296	67.3	4
473.00	POLES, TOWERS AND FIXTURES	75-R3	(75)	30,231,546	15,702,296	15,172,666	529,630	33.4	15,857
474.00	OVERHEAD CONDUCTOR	45-R3	(80)	20,514,612	10,498,681	9,327,713	1,170,968	32.3	36,253
474.10	OVERHEAD SERVICES	45-R4	(10)	2,849,453	1,125,671	1,340,123	(214,452)	33.4	(6,421)
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	9,111,686	5,533,568	3,578,118	32.6	109,758
475.10	UNDERGROUND SERVICES	45-R3	(10)	2,953,077	1,016,443	1,052,955	(36,512)	28.5	(1,281)
476.10	METERS	40-R4	0	1,683,985	682,328	68,871	613,457	10.6	57,873
476.30	AMR - METERS	15-L0	0	67,646	14,259	-	14,259	12.3	1,159
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	(10)	3,131,073	1,765,608	1,821,709	(56,101)	21.5	(2,609)
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	(10)	9,147,522	4,196,129	4,907,554	(711,425)	21.1	(33,717)
478.20	SENTINEL LIGHTS	30-R3	0	284,738	246,947	213,445	33,502	4.0	8,376
479.10	LINE TRANSFORMERS	23-R2	(10)	24,427,769	7,365,548	10,107,860	(2,742,312)	37.0	(74,117)
TOTAL DISTRIBUTION PLANT				117,541,619	51,877,234	49,697,805	2,179,429		111,136
GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	0	0	3,459,315	1,660,879	1,891,893	(231,014)	23.9	(9,666)
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	0	172,793	62,511	13,162	49,349	5.5	8,973
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	0	47,367	10,448	(11,313)	21,761	3.4	6,400
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	25	2,561,147	964,510	1,284,514	(320,004)	10.0	(32,000)
485.00	TOOLS AND INSTRUMENTS	12-L0	0	719,184	273,558	239,209	34,349	8.7	3,948
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	422,551	385,392	37,159	7.8	4,764
488.20	HOUSES	15-SQ	(10)	473,256	167,636	639,815	(472,179)	21.8	(21,660)
TOTAL GENERAL PLANT				8,305,904	3,562,093	4,442,674	(880,581)		(39,241)
TOTAL UTILITY PLANT IN SERVICE				145,424,111	63,912,691	63,596,048	316,643		74,125
					47,322,767	59,200,897	-11,878,130		-395,883
					16,589,924	4,395,151	12,194,773		470,009
					63,912,691	63,596,048	316,643		74,125

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION								
HYDRO PLANT (LIFE SPAN REMOVED)								
422.00	HYDRO STRUCTURES	0-ND	215,286	50,806	123,192	(72,386)	64.1	(1,129)
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	1,875,073	197,696	662,044	(464,347)	97.7	(4,753)
425.00	HYDRO GENERATORS	103-R3	1,458,435	104,415	315,135	(210,720)	81.9	(2,573)
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	105,192	48,259	99,610	(51,351)	34.3	(1,497)
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	68,657	19,448	39,992	(20,544)	27.7	(742)
TOTAL HYDRO PLANT			**3,722,643**	**420,625**	**1,239,974**	**(819,348)**		**(10,694)**
PRODUCTION DIESEL PLANT								
BEAVER CREEK (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	37,488	22,226	26,440	(4,213)	19.2	(219)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	92,859	40,692	50,013	(9,322)	22.0	(424)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	535,779	367,441	350,423	17,018	9.6	1,773
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	173,365	57,856	68,793	(10,937)	26.1	(419)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	48,603	8,070	10,719	(2,649)	34.9	(76)
TOTAL BEAVER CREEK			**888,094**	**496,285**	**506,387**	**(10,102)**		**635**
CARMACKS (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	167,739	43,699	52,552	(8,853)	31.7	(279)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	40,394	25,071	30,815	(5,744)	14.4	(399)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	419,543	309,237	294,915	14,323	8.3	1,726
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	101,158	34,682	40,647	(5,965)	24.7	(242)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	7,366	526	212	314	39.0	8
TOTAL CARMACKS			**736,201**	**413,215**	**419,141**	**(5,926)**		**814**
DESTRUCTION BAY (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	42,282	28,555	37,097	(8,543)	17.2	(497)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	105,478	40,635	67,047	(26,412)	23.3	(1,134)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	488,076	124,970	133,550	(8,580)	21.1	(407)
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	284,627	110,212	174,086	(63,874)	27.7	(2,306)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	28,048	9,297	18,011	(8,714)	34.7	(251)
TOTAL DESTRUCTION BAY			**948,512**	**313,669**	**429,792**	**(116,123)**		**(4,594)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION(LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	608,472	113,608	137,319	(23,711)	34.8	(681)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	619,132	248,855	305,938	(57,083)	21.9	(2,607)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	60,097	37,282	35,555	1,727	11.2	154
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	94,952	47,492	58,093	(10,601)	25.4	(417)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	2,454	1,480	1,989	(509)	36.5	(14)
TOTAL HAINES JUNCTION			**1,385,107**	**448,717**	**538,894**	**(90,177)**		**(3,565)**
OLD CROW (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	187,900	101,869	121,194	(19,324)	21.2	(912)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	215,087	82,975	101,983	(19,008)	24.1	(789)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	1,223,713	529,491	505,966	23,525	15.7	1,498
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	119,365	68,323	80,570	(12,247)	18.9	(648)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	171,496	66,372	91,261	(24,889)	27.3	(912)
TOTAL OLD CROW			**1,917,561**	**849,030**	**900,974**	**(51,944)**		**(1,762)**
PELLY CROSSING (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	48,892	33,045	40,186	(7,140)	15.9	(449)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	129,302	91,469	114,166	(22,697)	27.4	(828)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	474,056	299,952	286,219	13,732	10.9	1,260
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	431,735	151,302	199,681	(48,379)	25.3	(1,912)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	61,485	17,984	27,361	(9,377)	33.4	(281)
TOTAL PELLY CROSSING			**1,145,469**	**593,752**	**667,613**	**(73,860)**		**(2,211)**
ROSS RIVER (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	171,221	56,918	68,182	(11,264)	29.4	(383)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	85,126	32,959	40,510	(7,551)	22.2	(340)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	189,753	147,095	140,282	6,813	7.3	933
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	124,872	48,576	58,732	(10,156)	23.5	(432)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	9,639	1,747	2,208	(461)	35.5	(13)
TOTAL ROSS RIVER			**580,611**	**287,296**	**309,914**	**(22,619)**		**(235)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	247,966	63,443	76,361	(12,918)	32.0	(404)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	65,107	14,921	18,103	(3,182)	28.6	(111)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	45,677	24,846	21,626	3,220	10.9	295
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	70,425	26,610	32,538	(5,928)	24.9	(238)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	84,682	6,880	9,638	(2,758)	38.1	(72)
TOTAL STEWART CROSSING			**513,857**	**136,700**	**158,267**	**(21,567)**		**(530)**
SWIFT RIVER (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	22,503	9,878	11,772	(1,894)	25.6	(74)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	63,430	37,645	46,269	(8,624)	15.7	(549)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	241,047	98,815	94,569	4,245	16.3	260
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	93,560	31,048	37,516	(6,468)	25.1	(258)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	11,924	3,171	4,249	(1,078)	31.3	(34)
TOTAL SWIFT RIVER			**432,465**	**180,557**	**194,375**	**(13,819)**		**(655)**
TESLIN (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	37,986	10,389	12,402	(2,013)	31.2	(65)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	99,863	22,619	27,801	(5,181)	27.5	(188)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	762,034	524,432	500,142	24,290	9.6	2,530
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	54,417	25,006	27,410	(2,404)	21.5	(112)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	69,778	9,088	11,989	(2,901)	35.6	(82)
TOTAL TESLIN			**1,024,077**	**591,534**	**579,744**	**11,790**		**2,084**
WATSON LAKE (LIFE SPAN REMOVED)								
442.00	STRUCTURES AND IMPROVEMENTS	0	359,393	203,938	242,320	(38,382)	20.1	(1,910)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	747,818	108,117	132,885	(24,768)	30.6	(809)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	2,169,195	1,318,706	1,256,361	62,346	11.3	5,517
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	578,189	305,256	366,604	(61,348)	22.3	(2,751)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	258,430	61,919	83,525	(21,606)	33.8	(639)
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**2,081,695**	**(83,759)**		**(592)**
TOTAL PRODUCTION DIESEL PLANT			**13,684,978**	**6,308,691**	**6,786,796**	**(478,105)**	**-**	**(10,610)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2A: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011
DEPRECIATION RATES HAVE NOT INCLUDED THE USE OF A LIFE SPAN ANALYSIS
RELATED TO THE RECOVERY OF THE ORIGINAL COST OF INVESTMENT

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE								
442.00	STRUCTURES AND IMPROVEMENTS	0	10,662	8,809	10,466	(1,657)	9.3	(178)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	25,562	16,999	20,893	(3,894)	12.8	(304)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	568,500	303,283	287,763	15,520	13.1	1,185
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	87,652	40,799	48,221	(7,422)	23.1	(321)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	92,170	12,008	16,120	(4,112)	35.5	(116)
TOTAL MOBILE			**784,546**	**381,898**	**383,463**	**(1,565)**		**265**
TOTAL GENERATION			**18,192,167**	**7,111,214**	**8,410,233**	**(1,299,018)**		**(21,039)**
SUBSTATION PLANT								
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	1,384,421	626,639	829,972	(203,333)	31.0	(6,559)
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**829,972**	**(203,333)**		**(6,559)**
DISTRIBUTION PLANT								
471.00	LAND RIGHTS	0	1,267,608	151,638	151,507	131	67.3	2
473.00	POLES, TOWERS AND FIXTURES	75-R3	30,231,546	8,972,741	11,487,576	(2,514,836)	33.4	(75,294)
474.00	OVERHEAD CONDUCTOR	45-R3	20,514,612	5,832,601	7,036,909	(1,204,309)	32.3	(37,285)
474.10	OVERHEAD SERVICES	45-R4	2,849,453	1,023,337	1,271,831	(248,494)	33.4	(7,440)
475.00	UNDERGROUND CONDUIT	45-R3	20,982,589	6,074,457	5,608,170	466,287	32.6	14,303
475.10	UNDERGROUND SERVICES	45-R3	2,953,077	924,039	1,049,337	(125,298)	28.5	(4,396)
476.10	METERS	40-R4	1,683,985	682,328	41,448	640,880	10.6	60,460
476.30	AMR - METERS	15-L0	67,646	14,259	-	14,259	12.3	1,159
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	3,131,073	1,605,098	1,950,231	(345,133)	21.5	(16,053)
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	9,147,522	3,814,663	5,173,329	(1,358,667)	21.1	(64,392)
478.20	SENTINEL LIGHTS	30-R3	284,738	246,947	319,069	(72,122)	4.0	(18,030)
479.10	LINE TRANSFORMERS	23-R2	24,427,769	6,695,953	9,796,355	(3,100,402)	37.0	(83,795)
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**43,885,763**	**(7,847,703)**		**(230,761)**
GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	0	3,459,315	1,660,879	2,027,012	(366,133)	23.9	(15,319)
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	172,793	62,511	17,775	44,736	5.5	8,134
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	47,367	10,448	(11,313)	21,761	3.4	6,400
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	2,561,147	964,510	1,693,246	(728,736)	10.0	(72,874)
485.00	TOOLS AND INSTRUMENTS	12-L0	719,184	273,558	239,068	34,490	8.7	3,964
486.00	COMMUNICATION EQUIPMENT	15-SQ	872,842	422,551	391,629	30,922	7.8	3,964
488.20	HOUSES	15-SQ	473,256	152,396	1,717,512	(1,565,115)	21.8	(71,794)
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**6,074,929**	**(2,528,076)**		**(137,525)**
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,322,767**	**59,200,897**	**(11,878,130)**		**(395,883)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION									
HYDRO PLANT (LIFE SPAN OF 2052)									
422.00	HYDRO STRUCTURES	0-ND	(10)	215,286	5,081	813	4,268	64.1	67
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	(10)	1,875,073	19,770	4,367	15,402	97.7	158
425.00	HYDRO GENERATORS	103-R3	(10)	1,458,435	10,442	2,079	8,363	81.9	102
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	(10)	105,192	4,826	657	4,169	34.3	122
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	(10)	68,657	1,945	264	1,681	27.7	61
TOTAL HYDRO PLANT				**3,722,643**	**42,063**	**8,180**	**33,883**		**509**
PRODUCTION DIESEL PLANT									
BEAVER CREEK (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,488	2,223	(3,232)	5,454	19.2	284
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	92,859	8,138	1,494	6,645	22.0	302
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	535,779	36,744	20,345	16,399	9.6	1,708
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	173,365	-	2,313	(2,313)	26.1	(89)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	48,603	-	628	(628)	34.9	(18)
TOTAL BEAVER CREEK				**888,094**	**47,105**	**21,549**	**25,556**		**2,188**
CARMACKS (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	167,739	4,370	(6,423)	10,793	31.7	340
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	40,394	5,014	920	4,094	14.4	284
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	419,543	30,924	17,122	13,801	8.3	1,663
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	101,158	-	1,947	(1,947)	24.7	(79)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	7,366	-	529	(529)	39.0	(14)
TOTAL CARMACKS				**736,201**	**40,308**	**14,095**	**26,213**		**2,195**
DESTRUCTION BAY (LIFE SPAN OF 2023)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	42,282	2,855	(4,534)	7,390	17.2	430
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	105,478	8,127	2,003	6,124	23.3	263
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	488,076	12,497	7,754	4,743	21.1	225
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	284,627	-	882	(882)	27.7	(32)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	28,048	-	239	(239)	34.7	(7)
TOTAL DESTRUCTION BAY				**948,512**	**23,479**	**6,343**	**17,136**		**879**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
HAINES JUNCTION (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	608,472	11,361	(16,783)	28,144	34.8	809
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	619,132	49,771	9,138	40,633	21.9	1,855
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	60,097	3,728	2,064	1,664	11.2	149
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	94,952	-	235	(235)	25.4	(9)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	2,454	-	64	(64)	36.5	(2)
TOTAL HAINES JUNCTION				**1,385,107**	**64,860**	**(5,283)**	**70,143**		**2,802**
OLD CROW (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	187,900	10,187	(14,813)	24,999	21.2	1,179
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	215,087	16,595	3,046	13,549	24.1	562
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	1,223,713	52,949	29,376	23,573	15.7	1,501
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	119,365	-	3,340	(3,340)	18.9	(177)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	171,496	-	907	(907)	27.3	(33)
TOTAL OLD CROW				**1,917,561**	**79,731**	**21,856**	**57,875**		**3,033**
PELLY CROSSING (LIFE SPAN OF 2033)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	48,892	3,305	(4,912)	8,216	15.9	517
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	129,302	18,294	3,410	14,884	27.4	543
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	474,056	29,995	16,618	13,378	10.9	1,227
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	431,735	-	1,889	(1,889)	25.3	(75)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	61,485	-	513	(513)	33.4	(15)
TOTAL PELLY CROSSING				**1,145,469**	**51,594**	**17,518**	**34,075**		**2,197**
ROSS RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	171,221	5,692	(8,333)	14,025	29.4	477
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	85,126	6,592	1,210	5,382	22.2	242
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	189,753	14,710	8,145	6,565	7.3	899
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	124,872	-	926	(926)	23.5	(39)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	9,639	-	251	(251)	35.5	(7)
TOTAL ROSS RIVER				**580,611**	**26,993**	**2,199**	**24,795**		**1,572**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
STEWART CROSSING (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	247,966	6,344	(9,333)	15,677	32.0	490
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	65,107	2,984	548	2,436	28.6	85
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	45,677	2,485	1,256	1,229	10.9	113
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	70,425	-	143	(143)	24.9	(6)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	84,682	-	39	(39)	38.1	(1)
TOTAL STEWART CROSSING				**513,857**	**11,813**	**(7,348)**	**19,161**		**681**
SWIFT RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	22,503	988	(1,439)	2,427	25.6	95
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	63,430	7,529	1,382	6,147	15.7	392
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	241,047	9,881	5,491	4,391	16.3	269
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	93,560	-	624	(624)	25.1	(25)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	11,924	-	170	(170)	31.3	(5)
TOTAL SWIFT RIVER				**432,465**	**18,398**	**6,228**	**12,171**		**725**
TESLIN (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	37,986	1,039	(1,516)	2,555	31.2	82
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	99,863	4,524	830	3,693	27.5	134
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	762,034	52,443	29,038	23,405	9.6	2,438
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	54,417	-	3,301	(3,301)	21.5	(154)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	69,778	-	897	(897)	35.6	(25)
TOTAL TESLIN				**1,024,077**	**58,006**	**32,550**	**25,456**		**2,476**
WATSON LAKE (LIFE SPAN OF 2113)									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	359,393	20,394	(29,617)	50,011	20.1	2,488
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	747,818	21,623	3,969	17,654	30.6	577
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	2,169,195	131,871	72,943	58,928	11.3	5,215
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	578,189	-	8,293	(8,293)	22.3	(372)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	258,430	-	2,252	(2,252)	33.8	(67)
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**57,840**	**116,048**		**7,841**
TOTAL PRODUCTION DIESEL PLANT				**13,684,978**	**596,175**	**167,547**	**428,628**	**-**	**26,589**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE (*)	ESTIMATED NET SALVAGE	SURVIVING ORIGINAL COST AT 12/31/2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE									
442.00	STRUCTURES AND IMPROVEMENTS	0	(10)	10,662	881	(1,279)	2,160	9.3	232
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	40-R2.5	(20)	25,562	3,400	624	2,776	12.8	217
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	35-R4	(10)	568,500	30,328	16,707	13,621	13.1	1,040
446.00	ACCESSORY ELECTRIC EQUIPMENT	26-S2.5	0	87,652	-	1,899	(1,899)	23.1	(82)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	35-R3	0	92,170	-	516	(516)	35.5	(15)
TOTAL MOBILE				**784,546**	**34,609**	**18,467**	**16,142**		**1,392**
TOTAL GENERATION				**18,192,167**	**672,847**	**194,194**	**478,653**		**28,490**
SUBSTATION PLANT									
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	(10)	1,384,421	62,664	21,171	41,493	31.0	1,338
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**21,171**	**41,493**		**1,338**
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	0	0	1,267,608	-	(166)	166	67.3	2
473.00	POLES, TOWERS AND FIXTURES	75-R3	(75)	30,231,546	6,729,555	3,685,089	3,044,466	33.4	91,152
474.00	OVERHEAD CONDUCTOR	45-R3	(80)	20,514,612	4,666,080	2,290,803	2,375,277	32.3	73,538
474.10	OVERHEAD SERVICES	45-R4	(10)	2,849,453	102,334	68,292	34,041	33.4	1,019
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	3,037,229	(74,602)	3,111,831	32.6	95,455
475.10	UNDERGROUND SERVICES	45-R3	(10)	2,953,077	92,404	3,618	88,786	28.5	3,115
476.10	METERS	40-R4	0	1,683,985	-	27,423	(27,423)	10.6	(2,587)
476.30	AMR - METERS	15-L0	0	67,646	-	-	-	12.3	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	15-R2.5	(10)	3,131,073	160,510	(128,522)	289,032	21.5	13,443
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	40-R4	(10)	9,147,522	381,466	(265,776)	647,242	21.1	30,675
478.20	SENTINEL LIGHTS	30-R3	0	284,738	-	(105,624)	105,624	4.0	26,406
479.10	LINE TRANSFORMERS	23-R2	(10)	24,427,769	669,595	311,505	358,090	37.0	9,678
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**5,812,042**	**10,027,132**		**341,897**
GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	0	0	3,459,315	-	(135,119)	135,119	23.9	5,654
483.00	OFFICE FURNITURE AND EQUIPMENT	40-L3	0	172,793	-	(4,613)	4,613	5.5	839
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	15-SQ	0	47,367	-	-	-	3.4	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	5-SQ	25	2,561,147	-	(408,732)	408,732	10.0	40,873
485.00	TOOLS AND INSTRUMENTS	12-L0	0	719,184	-	141	(141)	8.7	(16)
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	-	(6,237)	6,237	7.8	800
488.20	HOUSES	15-SQ	(10)	473,256	15,240	(1,077,696)	1,092,936	21.8	50,135
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**(1,632,256)**	**1,647,495**		**98,283**
TOTAL UTILITY PLANT IN SERVICE			**-**	**145,424,111**	**16,589,924**	**4,395,151**	**12,194,773**	**-**	**470,009**

CW-YECL-34

Reference: Depreciation, Application, Section 7–Depreciation

In order to better understand the historical relationships reflected in net salvage and life analyses, it is necessary to have a better understanding of the type of investment currently in place, the type of investment recently retired, and various accounting practices.

Request:

(a) A detailed categorization of the investment in each account, along with the corresponding dollars of investment as of the end of the depreciation study period and any incremental periods available through the forecasted 2015 test year. The information should be provided on electronic medium in Excel readable format.

(b) The detailed categorization of investment by account retired, by year, for the past 10 years, along with the corresponding dollar value for such retirements. The information should be provided on electronic medium in Excel readable format.

(c) A detailed narrative identifying each separate major voltage upgrade program, along with the dollar level of retirement activity, by account, by year, associated with each such voltage upgrade program. The information should be provided on electronic medium in Excel readable format.

(d) A detailed narrative, corresponding support, and justification, including documentation, associated with the allocation of costs between cost of replacement activity and cost of removal in instances where replacement activity transpires. Further, indicate the timeframe when such policies went into effect and, if implemented within the last 10 years, identify the prior policy and explain the impact of each modification.

(e) Identify YECL's policy of applying group depreciation rates developed on a group basis to individual assets within the group. The response must state whether YECL ceases the booking of depreciation expense for any given asset within a group once that asset becomes, in YECL's opinion, fully accrued or whether YECL continues to apply the group-developed depreciation rate to all assets within the group as long as each item within the group is still plant in service.

Further, provide all support, justification, and documentation associated with the response.

(f) Whether YECL practices cradle to grave accounting or location accounting and if location accounting, which accounts have experienced such transactions, clearly identifying the actual accounting treatment as well as the dollar level of retirements, gross salvage, and cost of removal by year, by account, for the past 10 years.

(g) The annual level of retirements by account by year and the corresponding vintage year of addition due to the major capital expansion program being undertaken. The information should be provided on electronic medium in Excel readable format.

(h) A detailed narrative identifying the specific factors considered by account and the weighting of such factors in the determination of each specific average service life and corresponding dispersion pattern proposed. Further, provide all supporting and underlying documents associated with each weighting.

(i) A detailed narrative identifying the specific factors considered by account and the weighing of such factors in the determination of each specific net salvage value proposed. Further, provide all supporting and underlying documents associated with each weighting.

(j) All interview notes.

(k) All correspondence, memos, emails, etc. between YECL and Gannett Fleming.

(l) All site visit notes.

(m) All industry comparative data identifying life and/or salvage values, by account or subaccount, maintained by Gannett Fleming (not limited to Canada), identifying the specific utility, jurisdiction, and date corresponding to the establishment of the depreciation parameters.

(n) The fully loaded labor rate, by year, for the past five years, for an entry level laborer, machine operator, and a construction crew supervisor (i.e. the same particular type of construction crew member with the same level of experience in

each year such that the assumed laborer in all five years has the minimal years of experience), along with all supporting documentation.

(o) The basis, including all documentation, in support of assumed future labor escalation factors and how such factors were specifically incorporated into the depreciation analyses by account.

(p) A detailed description of YECL's current pole maintenance program and when such program was first implemented.

(q) A detailed description of YECL's current tower maintenance program and when such program was first implemented.

(r) The values of additions, retirements, gross salvage, cost of removal, etc., by account that were modified from YECL's continuing property records for inclusion and presentation in its depreciation study. Each adjustment should be categorized by year, account, and dollar amount. Further, provide the detailed reason for each modification.

(s) Each separate life table developed from each separate life analysis performed by account on electronic medium in Excel readable format. Further, provide the full basis why each resulting life-curve selection was rejected.

(t) The detailed analysis performed to allocate the accumulated provision for depreciation from the functional level to the current account level and to life and salvage components.

(u) A detailed narrative identifying and explaining the specific role that judgment and experience played in development of life and net salvage parameters for each account. The information should be provided in sufficient detail so as to clearly identify the role played by judgment and experience in establishment of the final value for each account. Further, provide all underlying documentation and support that verifies the reasonableness of the claimed role of judgment and experience as it influenced the final selection of life and net salvage parameters for each account.

(v) A copy of all work orders reflecting the retirement of a mile or more of transmission lines during the past 5 years.

(w) A detailed cause of retirement study by account.

(x) Whether the net salvage data is time synchronized with retirements, and if not, the maximum amount of time the data is not synchronized, by account.

(y) A copy of each depreciation-related schedule on electronic medium in Excel readable format.

Response:

(a) Please refer to the Application at Section 7, Schedules 7.2 to 7.4 for the investment in each account. Please refer to CW-YECL-34(a) Attachment 1 for a copy of the above information on electronic medium in Excel readable format.

(b) Please refer to Application at Section 7, Attachment 1, Part V. Net Salvage Statistics, pages 109-153. As stated in CW-YECL-34(y), the Gannett Fleming software outputs all reports in an MSWord format. As such an Excel version, of a number of the schedules is not available.

(c) Please refer to CW-YECL-34(c) Attachment 1 for retirement activity recorded for major voltage change projects.

(d) Since 2003-2004 (when the Oracle system was implemented), the process for the allocation of costs between replacement costs and costs of removal has generally been to use an estimated value derived by the engineering group based on their experience and professional judgment. This is the process used for straightforward projects such as replacing distribution facilities and other projects where it is administratively efficient and feasible to estimate accurately based on experience and professional judgment. For projects of a more complex nature for which estimates are not feasible (i.e. a-typical project with large direct costs of removal), removal costs would be directly charged using actual timesheets and invoices for removal costs. Replacement costs would be charged separately in this instance.

(e) Yukon Electrical does not depreciate any of its assets on an individual unit basis.

(f) Yukon Electrical practices cradle to grave accounting for all of its assets. Please refer to the Application at Section 7, Attachment 1, Part V, pages 109-153, for the retirements, gross salvage, and cost of removal by year, by account, for the past 10 years.

(g) Please refer to CW-YECL-34(g) Attachment 1.

(h) Please refer to YUB-YECL-84(b) Attachment 1.

(i) Please refer to CW-YECL-34(i) Attachment 1.

(j) Please refer to CW-YECL-34(j) Attachment 1.

(k) The complete basis for Yukon Electrical's position on appropriate Depreciation rates is the Depreciation Study itself, which has been filed and provides a full and comprehensive treatment of the issue. Yukon Electrical is not relying on any further documents or discussions in support of its position other than those provided in various parts of this response.

(l) The complete basis for Yukon Electrical's position on appropriate Depreciation rates is the Depreciation Study itself, which has been filed and provides a full and comprehensive treatment of the issue. Yukon Electrical is not relying on any further documents or discussions in support of its position other than those provided in various parts of this response.

(m) Please refer to CW-YECL-34(m) Attachments 1 and 2. Attachment 1 is a summary of average service life parameters for U.S.-based electric utilities where depreciation studies were conducted by Gannett Fleming. Attachment 2 provides a summary of average service life parameters by account structure for Canadian-based electric utilities. In providing these attachments, Gannett Fleming is identifying the companies for which the average service life parameters were developed. However, as not all of the studies are in the public domain, Gannett Fleming cannot identify the specific companies for which the specific statistics apply. As such, the companies for which the studies have been performed are listed separately from the actual identification of service life estimates. Other than for the utilities as listed in response to information requests YUB-YECL-87(a) and (c), Mr. Kennedy did not have any additional information regarding the utilities at the time the Yukon Electrical study was completed. Furthermore, Mr. Kennedy does not have any additional information regarding the utilities listed in CW-YECL-34(m) Attachment 1. The depreciation studies completed on behalf of the U.S.-based utilities were completed in the firm's three American-based offices by other Gannett Fleming analysts.

(n) Please refer to CW-YECL-34(n) Attachment 1. The salary rates are obtained from the Collective Agreements in place (Please refer to

CW-YECL-34(n) Attachment 2). The loading factors are system percentages that are applied to the salary base rates.

(o) Mr. Kennedy did not make any assumptions regarding future labour escalation factors. However, it should be noted that the Traditional method of net salvage analysis as presented in the Gannett Fleming study (which is the mostly widely accepted method of net salvage analysis throughout North America) does assume that the historic rate of inflation will be indicative of future rates of inflation. Gannett Fleming notes that, in large part, this assumption within the traditional method of net salvage analysis is the predominant reason that Regulatory Commissions throughout North America have historically preferred the traditional method of net salvage analysis as compared to methods such as the Constant Dollar Net Salvage method.

(p) Yukon Electrical's pole maintenance program has been in place for many years. Please refer to CW-YECL-34(p) Attachment 1 for a copy of ATCO Electric's Distribution Wood Pole Asset Management Guidelines. Yukon Electrical follows this guideline in completing pole maintenance. Yukon Electrical has utilized a qualified contractor for a formal test and treat program since 2008.

(q) Yukon Electrical has no towers in its system.

(r) Please refer to CW-YECL-34(r) Attachment 1. All adjustments and modifications are noted in the columns titled "Adjusted TY" and "Comments".

(s) Given the limited amount of retirement transactions, Mr. Kennedy did not view that any other combination of experience and placement bands would provide meaningful analysis. Therefore, no additional retirement rate analysis was prepared other than the retirement rate analysis as presented in the Gannett Fleming report. The Gannett Fleming software does not produce an observed life table in any other format than as presented in the "pdf format" in the Gannett Fleming report. As such, it is not possible to present the analysis in EXCEL format as requested in this information request.

(t) Yukon Electrical maintains its accumulated depreciation at an account level on a life and net salvage basis, not at a function level. As a result, Yukon Electrical is not required to allocate from the functional level to the account level.

(u) Please refer to the Gannett Fleming report, pages II-23 through II-29 for a detailed discussion of the factors considered in the average service life and net

salvage estimation. Please also refer to the attachments provided in response to information requests YUB-YECL-84(b) and YUB-YECL-87(c) for a description of the weighting applied by account by Gannett Fleming in the average service life and net salvage analysis.

(v) Yukon Electrical does not own or operate transmission lines. However, a copy of the work orders reflecting the retirement of a mile or more of distribution lines during the past 5 years are included as follows:

- CW-YECL-34(v) Attachment 1 – (2008) 9L – Km 129 to Km 132 South Klondike Highway – Distribution Line Rebuild (Project Y10637)
- CW-YECL-34(v) Attachment 2 – (2010) Lower Post Health Centre 3 Phase Line (Project Y11637)
- CW-YECL-34(v) Attachment 3 – (2011) Hotsprings Road Upgrade (Project Y11969)
- CW-YECL-34(v) Attachment 4 – (2012) 5L628 Crestview to Mayo Road Corner Double Circuit (Project Y12409)

(w) The complete basis for Yukon Electrical's position on appropriate Depreciation rates is the Depreciation Study itself, which has been filed and provides a full and comprehensive treatment of the issue. Yukon Electrical is not relying on any further documents or discussions in support of its position.

(x) Consistent with the use of the Traditional method of net salvage analysis, the net salvage data is not time synchronized. Please refer to the Gannett Fleming depreciation study, pages II-27 though II-29 for a discussion of the traditional method of net salvage analysis.

(y) Please refer to the following:

CW-YECL-34(y) Attachment 1 for Schedule 1A and 1B;

CW-YECL-34(y) Attachment 2 for Schedule 2A and 2B;

CW-YECL-34(y) Attachment 3 for Service Life Statistics;

CW-YECL-34(y) Attachment 4 for Net Salvage Statistics; and

CW-YECL-34(y) Attachment 5 for Detailed Depreciation Calculations.

The Gannett Fleming software outputs all reports in an MSWord format. As such an Excel version of a number of the schedules is not available. However, in order to be responsive to this information request, the MSWord version has been attached.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Calculation of Depreciation Expense 2013
($000s)

Line No.	Acct.	Description	Cross Ref.	2013 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2013 Total Depreciation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		263	2.40%	6	180	2	8
4	423 00	Hydro Resv, Dams & Waterways		2,375	2.40%	57	1,627	20	77
5	425 00	Hydro Generators		2,676	2.68%	72	1,833	25	97
6	426 00	Hydro Accessory Electrical Equip		158	2.58%	4	108	1	5
7	427 00	Hydro Misc Equip		69	4.07%	3	47	1	4
8		Total Production - Hydro		5,539		142	3,794	49	191
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,238	3.07%	69	491	8	77
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	3.69%	116	688	13	129
13	445 00	Generating Equipment & Prime Mover - Other		7,270	4.24%	308	1,594	34	342
14	446 00	Accessory Electric Equipment - Other		2,077	3.32%	69	455	8	77
15	447 00	Misc. Power Plant Equipment - Other		794	2.92%	23	174	3	26
16		Total Production - Diesel		15,517		585	3,402	66	651
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.25%	31	-	-	31
20		Total Transmission		1,384		31	-	-	31
21									
22		Distribution Plant							
23	471 00	Land Rights		1,331	1.51%	20	102	1	21
24	473 00	Poles, Towers & Fixtures		34,533	4.20%	1,450	2,559	54	1,504
25	474 00	Overhead Conductor		22,282	4.16%	927	1,703	35	962
26	474 10	Services - Overhead		2,979	2.57%	77	228	3	80
27	475 00	Underground Conductor		22,880	3.61%	826	1,732	31	857
28	475 10	Services - Underground		3,097	2.87%	89	237	3	92
29	476 10	Meters		1,984	7.65%	152	542	-	152
30	476 30	AMR - Meters		68	7.31%	5	-	-	5
31	477 10	Substation Equipment		3,131	2.75%	86	239	3	89
32	478 10	Street Lighting		9,600	3.77%	362	396	7	369
33	478 20	Sentinel Lights		285	2.99%	9	-	-	9
34	479 10	Line Transformers		28,058	2.66%	746	2,032	27	773
35		Total Distribution Plant		130,227		4,749	9,770	164	4,913
36									
37		General Plant							
38	482 00	Structures & Improvements		3,634	2.63%	96	1,124	15	111
39	483 00	Office Furniture & Equipment		194	5.70%	11	11	-	11
40	483 20	Computer Equipment		47	18.73%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		2,954	6.44%	190	432	14	204
42	485 00	Tool & Work Equipment		843	6.33%	53	86	3	56
43	486 00	Communication Structures & Equipment		938	5.50%	52	65	2	54
44	488 20	Company Housing		475	2.93%	14	-	-	14
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,251	4.00%	-	650	26	26
47	493 00	Demand Side Management		-	10.00%	-	481	48	48
48	496 00	Software		2,204	10.00%	220	705	35	255
49		Total General Plant		12,541		645	3,555	143	788
50									
51		Plant Studied		165,208		6,152	20,522	422	6,574
52		Plant Not Studied - Land		380					
53		Total Plant	S.8.6 L.10	165,588					

Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Calculation of Depreciation Expense 2014
($000s)

Line No.	Acct.	Description	Cross Ref.	2014 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2014 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		442	2.79%	12	157	2	14
4	423 00	Hydro Resv, Dams & Waterways		4,001	2.60%	104	1,421	18	122
5	425 00	Hydro Generators		4,508	2.77%	125	1,601	22	147
6	426 00	Hydro Accessory Electrical Equip		266	2.87%	8	94	1	9
7	427 00	Hydro Misc Equip		116	4.46%	5	41	1	6
8		Total Production - Hydro		9,334		254	3,315	44	298
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,729	3.13%	85	649	10	95
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,826	3.80%	145	910	17	162
13	445 00	Generating Equipment & Prime Mover - Other		8,865	4.34%	384	2,109	46	430
14	446 00	Accessory Electric Equipment - Other		2,532	3.52%	89	602	11	100
15	447 00	Misc. Power Plant Equipment - Other		968	2.96%	29	230	3	32
16		Total Production - Diesel		18,919		732	4,501	87	819
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.25%	31	-	-	31
20		Total Transmission		1,384		31	-	-	31
21									
22		Distribution Plant							
23	471 00	Land Rights		1,432	1.50%	21	113	1	22
24	473 00	Poles, Towers & Fixtures		37,092	4.20%	1,558	2,844	60	1,618
25	474 00	Overhead Conductor		23,985	4.16%	998	1,887	39	1,037
26	474 10	Services - Overhead		3,206	2.58%	83	252	3	86
27	475 00	Underground Conductor		24,612	3.61%	889	1,921	35	924
28	475 10	Services - Underground		3,334	2.86%	95	262	4	99
29	476 10	Meters		2,525	8.09%	204	(377)	-	204
30	476 30	AMR - Meters		68	7.13%	5	1,580	56	61
31	477 10	Substation Equipment		3,370	2.75%	93	265	4	97
32	478 10	Street Lighting		9,996	3.75%	375	945	18	393
33	478 20	Sentinel Lights		285	2.93%	8	-	-	8
34	479 10	Line Transformers		30,090	2.65%	797	2,364	31	828
35		Total Distribution Plant		139,997		5,126	12,057	251	5,377
36									
37		General Plant							
38	482 00	Structures & Improvements		4,758	2.67%	127	315	4	131
39	483 00	Office Furniture & Equipment		205	6.67%	14	9	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		3,386	6.59%	223	868	29	252
42	485 00	Tool & Work Equipment		930	6.67%	62	137	5	67
43	486 00	Communication Structures & Equipment		1,003	6.67%	67	11	-	67
44	488 20	Company Housing		475	2.91%	14	-	-	14
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		481	10.00%	48	522	26	74
48	496 00	Software		2,909	10.00%	291	7	-	291
49		Total General Plant		16,096		931	1,869	64	995
50									
51		Plant Studied		185,730		7,074	21,742	446	7,520
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	186,110					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Calculation of Depreciation Expense 2015
($000s)

Line No.	Acct.	Description	Cross Ref.	2015 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2015 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		600	2.91%	17	-	-	17
4	423 00	Hydro Resv, Dams & Waterways		5,422	2.68%	145	-	-	145
5	425 00	Hydro Generators		6,110	2.82%	172	-	-	172
6	426 00	Hydro Accessory Electrical Equip		360	2.97%	11	-	-	11
7	427 00	Hydro Misc Equip		157	4.51%	7	-	-	7
8		Total Production - Hydro		12,649		352	-	-	352
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		3,378	3.57%	120	798	14	134
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		4,736	4.59%	217	1,118	26	243
13	445 00	Generating Equipment & Prime Mover - Other		10,973	5.11%	561	2,592	66	627
14	446 00	Accessory Electric Equipment - Other		3,134	3.86%	121	740	14	135
15	447 00	Misc. Power Plant Equipment - Other		1,198	3.06%	37	283	4	41
16		Total Production - Diesel		23,420		1,056	5,531	124	1,180
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.24%	31	-	-	31
20		Total Transmission		1,384		31	-	-	31
21									
22		Distribution Plant							
23	471 00	Land Rights		1,545	1.50%	23	109	1	24
24	473 00	Poles, Towers & Fixtures		39,937	4.20%	1,677	2,736	57	1,734
25	474 00	Overhead Conductor		25,872	4.16%	1,076	1,825	38	1,114
26	474 10	Services - Overhead		3,459	2.58%	89	244	3	92
27	475 00	Underground Conductor		26,534	3.61%	958	1,855	33	991
28	475 10	Services - Underground		3,596	2.86%	103	254	4	107
29	476 10	Meters		2,148	7.40%	159	(377)	-	159
30	476 30	AMR - Meters		1,648	8.08%	133	2,283	92	225
31	477 10	Substation Equipment		3,636	2.75%	100	256	4	104
32	478 10	Street Lighting		10,941	3.76%	411	813	15	426
33	478 20	Sentinel Lights		285	2.87%	8	-	-	8
34	479 10	Line Transformers		32,454	2.65%	860	2,277	30	890
35		Total Distribution Plant		152,054		5,597	12,274	277	5,874
36									
37		General Plant							
38	482 00	Structures & Improvements		5,073	2.66%	135	305	4	139
39	483 00	Office Furniture & Equipment		214	6.67%	14	2	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		4,254	6.98%	297	730	25	322
42	485 00	Tool & Work Equipment		1,066	6.67%	71	84	3	74
43	486 00	Communication Structures & Equipment		1,014	6.67%	68	12	-	68
44	488 20	Company Housing		475	2.89%	14	-	-	14
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		1,003	10.00%	100	730	37	137
48	496 00	Software		2,916	10.00%	292	57	3	295
49		Total General Plant		17,965		1,076	1,920	72	1,148
50									
51		Plant Studied		207,472		8,112	19,725	473	8,585
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	207,852					

The Yukon Electrical Company Limited
Retirements Associated With Major Voltage Change Projects

Year	Project	Description	Account	Retirements	Vintage of Assets Retired	Note
2008-2012	Hillcrest Conversion	12.5kV to 25kV	Poles, Towers & Fixtures	778	1948,1975	1
			Overhead Conductors	100	1948	1
			Line Transformers	56	1975	1
2010	Takhini North	2400V system to 25kV system	Poles, Towers & Fixtures	4,181	1955,1970	2
			Overhead Conductors	620	1955,1970	2
			Line Transformers	2,510	1955,1970	2
2011	Lower Post Health Centre	1 Phase to 3 Phase Line	Poles, Towers & Fixtures	27,958	1985	3
			Overhead Conductors	886	1985	3
			Line Transformers	122	1985	3
			Street Lighting	185	1985	3
2011	Hotsprings Road	1 Phase to 3 Phase Line	Poles, Towers & Fixtures	3,110	1969,1973,2009	4
			Line Transformers	596	1969, 1973	4
2011	System Upgrade, Extension of 5L628 to Grizzly Valley	1 Phase to 3 Phase Line	N/A	-	N/A	5

Note 1 - The Hillcrest Conversion project is expected to include all retirements upon completion of the project in 2013.

Note 2 - This project had a limited number of retirements because the original poles and wiring were reused as much as possible.

Note 3 - There were a number of retirements in this project as some of the older line was not reuasble.

Note 4 - This project had a limited number of retirements because the majority of the work performed was for the additional two lines to the single phase line.

Note 5 - This project had no retirements because the existing single phase line was maintained and the two additional lines were added on.

The Yukon Electrical Company Limited
Additions and Retirements by Year 2013-2015

Line No.	Acct.	Description	Cross Ref.	2013 Opening	2013 Adds	2013 Retirements	2014 Opening	2014 Adds	2014 Retirements	2015 Opening	2015 Adds	2015 Retirements
1		Production - Hydro										
2												
3	422 00	Hydro Structures		263	180	-	442	167	(9)	600	-	-
4	423 00	Hydro Resv, Dams & Waterways		2,375	1,627	-	4,001	1,507	(86)	5,422	-	-
5	425 00	Hydro Generators		2,676	1,833	-	4,508	1,698	(97)	6,110	-	-
6	426 00	Hydro Accessory Electrical Equip		158	108	-	266	100	(6)	360	-	-
7	427 00	Hydro Misc Equip		69	47	-	116	44	(2)	157	-	-
8		Total Production - Hydro		5,539	3,794	-	9,334	3,515	(200)	12,649	-	-
9												
10		Production - Diesel										
11	442 00	Structures and improvement - Other		2,238	632	(141)	2,729	699	(49)	3,378	851	(53)
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	886	(198)	3,826	979	(69)	4,736	1,193	(75)
13	445 00	Generating Equipment & Prime Mover - Other		7,270	2,052	(458)	8,865	2,269	(161)	10,973	2,765	(173)
14	446 00	Accessory Electric Equipment - Other		2,077	586	(131)	2,532	648	(46)	3,134	790	(49)
15	447 00	Misc. Power Plant Equipment - Other		794	224	(50)	968	248	(18)	1,198	302	(19)
16		Total Production - Diesel		15,517	4,379	(977)	18,919	4,844	(343)	23,420	5,900	(369)
17				-								
18		Transmission		-								
19	457 00	Substation Equipment		1,384	-		1,384	-		1,384	-	
20		Total Transmission		1,384	-		1,384	-		1,384	-	
21												
22		Distribution Plant										
23	471 00	Land Rights		1,331	102		1,432	113		1,545	109	
24	473 00	Poles, Towers & Fixtures		34,533	2,639	(80)	37,092	2,925	(80)	39,937	2,817	(80)
25	474 00	Overhead Conductor		22,282	1,703		23,985	1,887		25,872	1,825	
26	474 10	Services - Overhead		2,979	228		3,206	252		3,459	244	
27	475 00	Underground Conductor		22,880	1,749	(16)	24,612	1,938	(16)	26,534	1,871	(16)
28	475 10	Services - Underground		3,097	237		3,334	262		3,596	254	
29	476 10	Meters		1,984	600	(58)	2,525	50	(427)	2,148	50	(427)
30	476 30	AMR - Meters		68			68	1,580		1,648	2,283	
31	477 10	Substation Equipment		3,131	239		3,370	265		3,636	256	
32	478 10	Street Lighting		9,600	396		9,996	945		10,941	813	
33	478 20	Sentinel Lights		285			285	-		285	-	
34	479 10	Line Transformers		28,058	2,144	(112)	30,090	2,376	(12)	32,454	2,289	(12)
35		Total Distribution Plant		130,227	10,037	(267)	139,997	12,593	(536)	152,054	12,810	(536)
36												
37		General Plant										
38	482 00	Structures & Improvements		3,634	1,131	(7)	4,758	321	(7)	5,073	312	(7)
39	483 00	Office Furniture & Equipment		194	44	(32)	205	42	(32)	214	34	(32)
40	483.20	Computer Equipment		47	-		47	-		47	-	
41	484 00	Transportation & Mobile Equipment		2,954	559	(127)	3,386	995	(127)	4,254	850	(120)
42	485 00	Tool & Work Equipment		843	117	(31)	930	167	(31)	1,066	115	(31)
43	486 00	Communication Structures & Equipment		938	65		1,003	11		1,014	12	
44	488 20	Company Housing		475	-		475	-		475	-	
45	491 00	Franchise & Consent		1	-		1	-		1	-	
46	492 00	License - Fish Lake		1,251	650		1,901	-		1,901	-	
47	493 00	Demand Side Management		-	481	-	481	522	-	1,003	730	
48	496 00	Software		2,204	705		2,909	7		2,916	57	
49		Total General Plant		12,541	3,752	(197)	16,096	2,066	(197)	17,965	2,110	(190)
50		Plant Studied		165,208	21,962	(1,440)	185,730	23,017	(1,276)	207,472	20,820	(1,095)
51												
52		Plant Not Studied - Land		380			380			380		
53												
54		Total Plant	S.8.6 L.6	165,588			186,110			207,852		

YUKON ELECTRICAL COMPANY LIMITED

SUMMARY OF RELATIVE WEIGHTING APPLIED TO VARIOUS CONSIDERATION IN THE ESTIMATION OF NET SALVAGE PERCENTAGES

	DESCRIPTION	RECOMMENDED NET SALVAGE PERCENTAGE	TRADITIONAL NET SALVAGE ANALYSIS	PEER ANALYSIS	MANAGEMENT AND OPERATING INTERVIEWS	GANNETT FLEMING EXPERIENCE
	(1)	(2)	(5)	(6)=(5)/(3)		
GENERATION						
HYDRO GENERATION (LIFE SPAN OF 2052)						
422.00	HYDRO STRUCTURES	-10	none	low	medium	high
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	-10	none	low	medium	high
425.00	HYDRO GENERATORS	-10	none	low	medium	high
426.00	HYDRO ACCESSORIES AND EQUIPMENT	-10	none	low	medium	high
427.00	HYDRO MISCELLANEOUS EQUIPMENT	-10	none	low	medium	high
DIESEL GENERATION						
442.00	STRUCTURES AND IMPROVEMENTS	-10	none	low	high	medium
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	-20	high	low	high	medium
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	-10	low	low	high	medium
446.00	ACCESSORY ELECTRIC EQUIPMENT	0	none	low	high	medium
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	0	low	low	high	medium
SUBSTATION PLANT						
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	0	none	none	none	none
DISTRIBUTION PLANT						
471.00	LAND RIGHTS	0	none	none	medium	high
473.00	POLES, TOWERS AND FIXTURES	-60	high	medium	medium	medium
474.00	OVERHEAD CONDUCTOR	-70	high	medium	medium	medium
474.10	OVERHEAD SERVICES	0	medium	medium	medium	medium
475.00	UNDERGROUND CONDUIT	-5	medium	medium	high	high
475.10	UNDERGROUND SERVICES	0	medium	medium	medium	medium
476.10	METERS	0	high	medium	medium	medium
476.30	AMR - METERS	0	low	low	low	low
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	0	low	medium	high	medium
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	-10	high	medium	medium	low
478.20	SENTINEL LIGHTS	-10	low	low	medium	low
479.10	LINE TRANSFORMERS	-5	low	medium	high	medium
GENERAL PLANT						
482.00	STRUCTURES AND IMPROVEMENTS	5	medium	medium	high	medium
483.00	OFFICE FURNITURE AND EQUIPMENT	0	none	none	none	none
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	0	none	none	none	none
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	20	high	high	high	low
485.00	TOOLS AND INSTRUMENTS	0	none	none	none	none
486.00	COMMUNICATION EQUIPMENT	0	none	none	none	none
488.20	HOUSES	-10	none	low	medium	medium

YUKON ELECTIRCAL COMPANY LIMITED

SUMMARY OF DISCUSSIONS HELD WITH MANAGEMENT AND OPERATION STAFF

HELD ON JANUARY 7, 2013

Automated Meter Reading Programs

The company is currently embarking on an AMR program to be implemented in 2014 and 2015. However, the systems being considered is not an AMI system and will not include customers in the isolated generation customers. It is anticipated that the system will be a Power Line Carrier system and will include approximately 14,000 of YECL's 17,000 customers. The AMR system will be similar to AMR systems on the Alberta ATCO Electric and Northland Utilities (Yellowknife) systems.

The AMR system will require all older technology meters to be replaced with new meters by 2020. It was determined that the investment associated with new AMR meters should be placed into a new Meters account (476.30), and that the life estimate of the old meters (account 476.10) should reflect the fact that most of the older meters will be removed from service by 2020. However, it was noted that the meters associated with isolated generation customers may remain in service beyond 2020.

Electric Generation Accounts

It was noted during prelimary review of the YECL data files that there was limited amounts of costs of removal charged to the generation accounts. During discussions it was determined that historically generation removal costs have been charged against the project costs for the replacement assets. YECL have indicated that this practice will be discontinued and the more appropriate practice of charging costs of removal against the FRSR accounts will be implemented immediately.

The concept of including a Life Span into the depreciation rate calculations was discussed. Gannett Fleming presented an over view of the Life Span concept and the considerations that YECL would need to review in the determination of an appropriate Life Span. Gannett Fleming stressed that Gannett Fleming can provide the criteria and factors to be considered to YECL, however, the selection of a Life Span date needs to be determined by YECL. YECL is much more familiar with the economic forces of potential retirement, and technology of the generation equipment. As such, YECL is in the best position to determine the Life Span date. Based on the discussion, the YECL management and operating staff committed to review the issue of Life Spans for each generation facility by January 24, 2013r

The Fish Lake Hydro facility was separately discussed. It is noted that a Water Management study is currently being undertaken. The continued use of a Life Span date ending in 2052 was reviewed. It was agreed that continued use of the 2052 is reasonable at this time

The diesel generation units' maintenance schedule was reviewed. Operations staff indicated that the units undergo a major capital overhaul 24,000 hours that results in replacement of approximately 25% of the units original investment. It was also noted that over the past 16 years 4 units have been removed and retired from service. However, over the next 3 year period 7 units will require replacement due to age and condition. As such, the pace of retirements will significantly increase over the next few years.

Vehicles

YECL follows the same vehicle replacement criteria as ATCO Electric. Operations staff have indicated that these guideline suggest replacement of vehicles after 7 years or 170,000 Km.

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 1 Survivor Curve	Company 2 Survivor Curve	Company 3 Survivor Curve	Company 4 Survivor Curve	Company 5 Survivor Curve	Company 6 Survivor Curve	Company 7 Survivor Curve	Company 8 Survivor Curve	Company 9 Survivor Curve	Company 10 Survivor Curve	Company 11 Survivor Curve	Company 12 Survivor Curve	Company 13 Survivor Curve	Company 14 Survivor Curve	Company 15 Survivor Curve	Company 16 Survivor Curve
	INTANGIBLE PLANT																	
302	FRANCHISES AND CONSENTS																	
303	MISCELLANEOUS INTANGIBLE PLANT		5 - SQ		5 - SQ									5 - SQ				
	SOFTWARE																	
	FIBER OPTIC											15 - SQ						
	5 YR																	
	10 YR																	
	15 YR																	
	25 YR																	
	RRSU UPGRADES																	
	STEAM PRODUCTION PLANT																	
310	LAND AND LAND RIGHTS - RIGHTS				SQUARE*				SQUARE*									
	REMOVING OTHER PROPERTY																SQUARE*	
	EASEMENTS, PERMITS																SQUARE*	
311	STRUCTURES AND IMPROVEMENTS		100 - R2.5		100 - R2.5*		100 - S2.5*	100 - S2*	100 - R2*	SQUARE*			115 - R1.5*	90 - S1*	75 - S1.5*		70 - S1.5*	
	LANDFILL																50 S3*	
	SECURITY																	
312	BOILER PLANT EQUIPMENT		80 - R0.5		80 - R0.5*		75 - R2*	75 - S2*	75 - R1.5*	SQUARE*			60 - L0.5*	60 - S1*	48 - L2*		60 - R1*	
	COMBUSTION INITIATIVE						10 - SQ							30 - S1*				
	UNIT COAL TRAIN						25 - R2		25 - R2				26 - R2.5					
	POWER OPERATED								20 - L2									
	UNCLASSIFIED								40 - S2									
	SCRUBBERS													25 - R0.5*				
	FUEL EQUIPMENT																	
	COAL PILE BASE																	
	POLLUTION CONTROL EQUIPMENT																	
	RETROFIT PRECIPITATORS																	
	CATALYST																	
	AQC																	
	CONTINUOUS EMISSION MONITORING																	
	TOOLS																	
	RAIL IMPROVEMENTS																	
313	ENGINES & GENERATORS													25 - R0.5*				
314	TURBOGENERATOR UNITS		60 - R0.5		60 - R0.5*		70 - R2.5*	75 - S3*	50 - R2*	SQUARE*			70 - L0.5*	25 - R0.5*	65 - R2*		40 - R0.5*	
315	ACCESSORY ELECTRIC EQUIPMENT		65 - R1.5		65 - R1.5*		70 - R3*	65 - R4*	50 - L2*	SQUARE*			80 - S0*	20 - S0*	60 - R2,5*		50 - R3*	
	COMBUSTION INITIATIVE																	
316	MISCELLANEOUS PLANT EQUIPMENT		65 - R2		65 - R2*		60 - R2*	60 - S1.5*	60 - R1.5*				60 - O1*		40 - R2*		53 - R2*	
	COMBUSTION INITIATIVE								10 - SQ									
	AIR MONITORING EQUIPMENT								15 - S3									
	FURNITURE								20 - SQ									
	DATA PROCESSING EQUIPMENT								7 - SQ									
	CARS								8 - L2.5									
	TOOLS, SHOP AND GARAGE EQUIPMENT								20 - L2									
	POWER OPERATED EQUIPMENT								20 - L2									
	COMMUNICATION EQUIPMENT								15 - SQ									
	SMALL TRUCKS																	
	LARGE TRUCKS																	
	TRAILERS																	
	MISCELLANEOUS								25 - SQ									
	NUCLEAR PRODUCTION																	
320	LAND AND LAND RIGHTS - RIGHTS																	
321	STRUCTURES AND IMPROVEMENTS												100 - R1*		65 - R2.5*			
322	REACTOR PLANT EQUIPMENT												60 - S0*		70 - R1*			
	STEAM GENERATORS														SQUARE*			
323	TURBOGENERATOR UNITS												60 - S0.5*		60 - S0*			
324	ACCESSORY ELECTRIC EQUIPMENT												80 - R2*		45 - R3*			
325	MISCELLANEOUS PLANT EQUIPMENT												60 - O3*		35 - R0.5*			
	HYDRAULIC PRODUCTION PLANT																	
330	LAND AND LAND RIGHTS - RIGHTS				SQUARE*												75 - R3*	
	REMOVING PROPERTY OF OTHERS																100 - R4*	
331	STRUCTURES AND IMPROVEMENTS				SQUARE*				100 - R2*				130 - R1*		SQUARE*		110 - R2*	
	FISH & WILDLIFE CONSERVATION																50 - S2.5*	
	RECREATION																50 - S0.5*	
332	RESERVOIRS, DAMS AND WATERWAYS				SQUARE*				100 - S1.5*				150 - L2*		SQUARE*		100 - R1*	
	FISH & WILDLIFE CONSERVATION																60 - S1*	
	RECREATION																60 - S1*	
333	WATER WHEELS, TURBINES AND GENERATORS				SQUARE*				75 - S2*				96 - S0.5*	40 - S2	SQUARE*		65 - R1.5*	
334	ACCESSORY ELECTRIC EQUIPMENT				SQUARE*				20 - O1*				65 - R0.5*		SQUARE*		38 - R2.5*	
335	MISCELLANEOUS PLANT EQUIPMENT				SQUARE*				50 - R2.5				60 - R0.5*	45 - R3	SQUARE*		65 - R1.5*	
	EQUIPMENT																	

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client: Company 1 Survivor Curve	Company 2 Survivor Curve	Company 3 Survivor Curve	Company 4 Survivor Curve	Company 5 Survivor Curve	Company 6 Survivor Curve	Company 7 Survivor Curve	Company 8 Survivor Curve	Company 9 Survivor Curve	Company 10 Survivor Curve	Company 11 Survivor Curve	Company 12 Survivor Curve	Company 13 Survivor Curve	Company 14 Survivor Curve	Company 15 Survivor Curve	Company 16 Survivor Curve
	FURNITURE																
	COMPUTER																
	FISH & WILDLIFE CONSERVATION															40 - R3*	
	RECREATION															40 - R3*	
336	ROADS, RAILROADS AND BRIDGES			SQUARE*				75 - R4				40 - O2*		SQUARE*		55 - S2*	
	OTHER PRODUCTION PLANT																
340	LAND AND LAND RIGHTS - RIGHTS			SQUARE*													
341	STRUCTURES AND IMPROVEMENTS			SQUARE*		50 - S2*	40 - S4*	SQUARE*	SQUARE*		SQUARE*	40 - R4	90 - S1*	80 - S1*		55 - S4*	120 - R1.5*
	COMBINED CYCLE PRODUCTION																
342	FUEL HOLDERS					55 - R2.5*	50 - S0.5*	SQUARE*				40 - R4	35 - S2.5*	70 - S1*		55 - R3*	SQUARE*
	COMBINED CYCLE PRODUCTION																
343	PRIME MOVERS			SQUARE*		43 - S2*	40 - L4*	SQUARE*					24 - O1*	70 - L1.5*		55 - S2.5*	70 - R0.5*
	SOLAR													12 - SQ			
	WIND TURBINE																
	FUEL CELLS																
	BASE LOAD																
	PEAKERS																
	CONTINUOUS EMISSION MONITORING																
	COMBINED CYCLE PRODUCTION																
344	GENERATORS			SQUARE*		50 - R3*	60 - S2.5*	SQUARE*	SQUARE*		SQUARE*	40 - R4	25 - R0.5*	37 - R3*		45 - R1*	70 - L0*
	PORTABLE POWER MODULES																
	SOLAR															25 - S2.5*	
	WIND																
345	ACCESSORY ELECTRIC EQUIPMENT			SQUARE*		40 - S1*	30 - R1.5*	SQUARE*	SQUARE*		SQUARE*	40 - R4	25 - R0.5*	50 - S2*		20 - S2*	
	COMBINED CYCLE PRODUCTION																
	WIND																
346	MISCELLANEOUS PLANT EQUIPMENT			SQUARE*		40 - R2*	30 - R4	SQUARE*	SQUARE*			25 - R1	20 - S0*	70 - L1*		35 - R3*	SQUARE*
	COMBINED CYCLE PRODUCTION																
	SOLAR PRODUCTION																
	WIND																
	A/V																
348	EASEMENTS																
	TRANSMISSION PLANT																
350	LAND AND LAND RIGHTS - RIGHTS		70 - R4	SQUARE*					75 - R4	65 - R4						75 - R4	
351	EASEMENTS																
352	STRUCTURES AND IMPROVEMENTS	50 - R3	50 - R3	SQUARE*	45 - R3				50 - R4	40 - R2.5	50 - R4	60 - R2	45 - R2.5	50 - R4		60 - S2	
	MAJOR																
	SMALL																
	NON SYS CONTROL/COM																
	SYS CONTROL/COM																
353	STATION EQUIPMENT	50 - R2	50 - R2	50 - R2*	45 - R0.5				40 - R1	45 - R0.5	50 - R2	55 - R2.5	45 - S1.5	42 - R3		45 - R2.5	47 - R2
	STEP-UP TRANSFORMERS	50 - R2*															
	STEP-UP EQUIPMENT																
	MISCELLANEOUS / OTHER																
	MICROWAVE																
	SCADA	15 - S3	15 - S3														13 - L2
	SUPERVISORY EQUIPMENT																
	SUBSTATION ON CUSTOMER PREMISES																
	PORTABLE PROPERTY AT SUBSTATIONS																
	METERING STATION																
	NON SYS CONTROL/COM																
	SYS CONTROL/COM																
	RTU																
	ELECTRONICS																
	MAJOR																
	COMMUNICATION EQUIPMENT																
	SECURITY																
	LEASEHOLD																
354	TOWERS AND FIXTURES	65 - R4	65 - R4	65 - R4*	65 - R4				60 - S2	65 - R2.5	65 - R3	70 - R4		60 - R3		70 - R4	50 - S3
	ROW CLEARING																
355	POLES AND FIXTURES	55 - R2.5	55 - R2.5		50 - R2.5				45 - S2	55 - R2	45 - R1	53 - R4	45 - R2.5			65 - R2.5	48 - R2.5
	ROW CLEARING																
	POLES AND FIXTURES - WOOD													48 - R1.5			
	POLES AND FIXTURES - STEEL													55 - R3			
	MINT LINE																
	LEASEHOLD																
356	OVERHEAD CONDUCTORS AND DEVICES	50 - R2.5	55 - R2.5	50 - R2*	45 - S3				50 - S4	55 - R1.5	55 - R0.5	55 - R4	40 - R2	55 - R3		65 - R2.5	45 - R3
	ROW CLEARING	70 - R4	70 - R4														
	ON TOWERS																
	MINT LINE																
357	UNDERGROUND CONDUIT		55 - S3						50 - R2.5					48 - S1.5		60 - R4	60 - R4
358	UNDERGROUND CONDUCTORS AND DEVICES		45 - R3		35 - R3				35 - R2.5					40 - R3		50 - S2	35 - R3
	SUB. CABLE - SOUTH																
	SUB. CABLE - NORTH																
359	ROADS AND TRAILS			SQUARE*					60 - R4			50 - SQ				65 - R4	60 - R4

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 1	Company 2	Company 3	Company 4	Company 5	Company 6	Company 7	Company 8	Company 9	Company 10	Company 11	Company 12	Company 13	Company 14	Company 15	Company 16
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	DISTRIBUTION PLANT																	
360	LAND & LAND RIGHTS - RIGHTS		70 - R4	70 - R4							65 - R4						75 - R4	70 - SQ
	EASEMENTS, SURVEYS AND CLEARING																	
361	STRUCTURES AND IMPROVEMENTS		50 - R3	50 - R3		45 - S3	53 - R2.5	50 - R2.5	47 - R1.5	45 - R2.5	60 - R3	60 - R3	60 - R2.5	45 - R2.5	45 - R2.5	52 - R2.5	60 - R2.5	50 - R2
	STRUCTURES AND IMPROVEMENTS - MAJOR																	
	STRUCTURES AND IMPROVEMENTS - SMALL																	
	LEASEHOLD																	
362	STATION EQUIPMENT		50 - R2	50 - R2	SQUARE*	25 - R1	48 - R2.5	25 - O1	40 - R1.5	40 - R1	50 - R2	50 - R4	60 - R2.5	40 - R1.5	38 - S0	45 - R2.5	45 - R1.5	43 - R2.5
	MAJOR																	
	ELECTRONIC																	
	SCADA		15 - S3	15 - S3														13 - L2
	COMPANY STATIONS																	
	CUSTOMER HIGH TENSION																	
	CONTROL CENTER						10 - S4											
	SUPERVISORY																	
	TRANSFORMERS																	
	OTHER																	
	SECURITY																	
	COMMUNICATION EQUIPMENT																	
	LEASEHOLD																	
	REMOTE MONITORING EQUIPMENT																	
363	STORAGE BATTERY EQUIPMENT																	
363.5	STATION EQUIPMENT - ELECTRONICS																	
364	POLES, TOWERS AND FIXTURES		55 - R3	55 - R3	40 - R1	48 - R1.5	50 - R3	47 - R1	43 - R1	40 - R2	40 - R4	40 - R1	45 - R2.5	38 - R0.5		48 - R2	55 - R2.5	45 - S1
	POLES, TOWERS AND FIXTURES - WOOD POLES														38 - R0.5			
	POLES, TOWERS AND FIXTURES - STEEL TOWERS																	
	CUSTOMER TRANSFORMER STATION																	
	POLES																	
	CLEARING TOWERS																	
	CLEARING POLES																	
	STEEL														50 - R3			
365	OVERHEAD CONDUCTORS AND DEVICES		50 - R1.5	50 - R1.5	40 - R2	33 - L1	55 - R3	42 - R1	38 - R1.5	40 - R1.5	40 - R3	45 - R1	49 - R1	33 - R1	53 - O1	48 - R2	50 - R3	48 - S1.5
	ROW CLEARING		70 - R4	70 - R4														
366	UNDERGROUND CONDUIT		50 - R2.5	50 - R2.5		26 - S3	70 - R4	40 - R3	43 - S1	45 - R2.5	50 - R2.5	50 - S4	70 - R3	45 - S1	55 - R1.5	55 - R5	50 - S2	60 - R3
	ENCASED																	
	NOT ENCASED																	
	UNDERGROUND CONDUIT - MANHOLES																	
367	UNDERGROUND CONDUCTORS AND DEVICES		35 - S3	35 - S3		34 - S1	48 - R3	42 - R2	40 - R1	35 - R1.5	38 - R4	40 - R2	54 - R2	37 - R0.5	29 - L1	45 - R4	28 - S2	47 - R2.5
	CABLE INJECT																	
	DUCT SYSTEM																	
	DIRECT BURIED																	
368	LINE TRANSFORMERS				35 - R2	35 - R1.5	45 - R3	39 - R1	28 - R1	30 - R1	35 - S1	45 - R2.5	42 - R2.5		36 - R3	32 - S1	44 - R2	39 - R2
	TRANSFORMER INSTALLATIONS																	
	OVERHEAD		40 - R2.5	40 - R2.5										26 - R0.5				
	UNDERGROUND		33 - R4	33 - R4										31 - S1.5				
	PAD MOUNT																	
	NON-NETWORK HOUSING																	
	NETWORK																	
	UNDERGROUND RESIDENTIAL DISTRIBUTION																	
	CUSTOMER																	
369	SERVICES					40 - O1	43 - R2	40 - O1		35 - R3	30 - R2	30 - R3			37 - S2			45 - R4
	OVERHEAD		45 - R4						52 - R1				40 - R2.5	38 - R0.5		55 - R4	55 - R4	
	UNDERGROUND		40 - S3						52 - R1				55 - R3	46 - R1		55 - R4	55 - R4	
	UNDERGROUND CABLE																	
370	METERS		40 - R4	40 - R4		45 - S4	36 - R1	43 - R1.5	23 - R1	25 - R0.5	30 - R2.5	35 O1	26 - L2.5	20 - L1.5	23 - R1	32 - R1.5		33 - R2.5
	METER INSTALLATIONS								45 - R3									
	METERING DEVICES								16 - R0.5									
	AMR AND ELECTRONIC														12 - S2			12 - S2
	LOAD RESEARCH METERS																	
	AMI METERS																	
	IDAHO STANDARD																18 - L0.5	
	IDAHO AMR																15 - S2.5	
	WASHINGTON STANDARD																35 - S0	
371	INSTALLATIONS ON CUSTOMERS' PREMISES								25 - S3				20 - O1		30 - R1	32 - R3		
	AREA LIGHTING															32 - R3		
	PHOTOVOLTAIC INSTALLATIONS																	
	LOAD CONTROL DEVICES															32 - R3		
372	LEASED PROPERTY															30 - S3		
373	STREET LIGHTING AND SIGNAL SYSTEMS		30 - R1	30 - R1	25 - R1	27 - L0	30 - R1.5	23 - L1	27 - R2	25 - L0	17 - S1.5	35 R2	36 - L1	33 - S0.5	35 - R2		35 - R2.5	
	MERCURY VAPOR																	28 - R3
	HIGH PRESSURE SODIUM																35 - R2.5	20 - S2
	OVERHEAD															22 - R3		
	UNDERGROUND								26 - R1.5							22 - R3		
	TRANSFORMERS																	
	BOULEVARD																	
	CUSTOMER POLES																	
	DUCK TO DAWN																	
	NONROADWAY LIGHTING																	
	CONDUIT AND CABLE																	
	LAMPS AND EQUIPMENT																	
	ELECTROLIERS																	
375	EASEMENTS																	

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 1	Company 2	Company 3	Company 4	Company 5	Company 6	Company 7	Company 8	Company 9	Company 10	Company 11	Company 12	Company 13	Company 14	Company 15	Company 16
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	GENERAL PLANT																	
389	LAND & LAND RIGHTS - RIGHTS			70 - R4														
390	STRUCTURES AND IMPROVEMENTS		50 - R1*	50 - R1*	SQUARE*	35 - R2.5	45 - R2.5	50 - S3	40 - R0.5	50 - R4	55 - O1	55 - O1	45 - R1.5	65 - R2*	39 - R1	45 - R2	48 - S2	
	LEASEHOLD IMPROVEMENTS		SQUARE*		SQUARE*		30 - S3	20 - S3										
	LARGE																	### - R1*
	SMALL																	40 - R1
	AIR CONDITIONING																	
	PAD																	
	LEASE																	
	MISCELLANEOUS																	
391	OFFICE FURNITURE & EQUIPMENT				20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	15 - SQ			15 - SQ	10 - SQ				
	FURNITURE		20 - SQ	20 - SQ							20 - SQ	20 - SQ			20 - SQ	20 - SQ		20 - SQ
	EQUIPMENT										10 - SQ	10 - SQ			10 - SQ			10 - SQ
	COMPUTERS AND SOFTWARE					5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ			5 - SQ
	COMPUTER HARDWARE																5 - SQ	
	SOFTWARE																	
	LARGE APPLICATION SOFTWARE																	
	DATA HANDLING		10 - SQ	10 - SQ												5 - SQ		
	INFORMATION SYSTEMS		10 - SQ	10 - SQ												5 - SQ		
	AML&P - EKLUTNA													7 - SQ				
	POWER MANAGEMENT SYSTEMS																	
	CASH PROCESSING EQUIPMENT																	
	EDP																	
	SYSTEM DEVELOPMENT																	
392	TRANSPORTATION EQUIPMENT						18 - L1.5			11 - L0.5	12 - L1.5		11 - R1	12 - S1		10 - R2.5	15 - L2.5	
	PASSENGER CARS & VANS		7 - S3		5 - S3							14 - L2						5 - L1.5
	TRUCKS, TRAILERS AND VANS					12 - R5		13 - L3				14 - L2						
	LIGHT TRUCKS		11.5 - L4	11.5 - L4														
	MEDIUM TRUCKS		11.5 - L4		15 - L2													
	HEAVY TRUCKS								13 - R0.5									
	MEDIUM TRUCKS / POWER EQUIPPED																	
	HEAVY TRUCKS / POWER EQUIPPED																	
	AIRPLANES AND HELICOPTERS																	
	AIRPLANES																	
	HELICOPTERS																	
	TRACTORS																	
	TRAILERS		18 - L1	18 - L1					21 - S2.5							10 - R2.5		
	MOTOR HOME																	
	OTHER		15 - SQ															
	SUBUNIT																	
393	STORES EQUIPMENT		20 - SQ	20 - SQ	20 - SQ		25 - SQ	25 - SQ		20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	25 - SQ	25 - SQ	20 - SQ
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	20 - SQ	20 - SQ	25 - SQ	25 - SQ	25 - SQ	25 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	25 - SQ	20 - SQ	
	ELECTRIC VEHICLES																	
395	LABORATORY EQUIPMENT		20 - SQ	20 - SQ	20 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	
396	POWER OPERATED EQUIPMENT		18 - L1	18 - L1	15 - L2	12 - L5	18 - L2.5	13 - L3	18 - L1	10 - L0	25 - R1.5	14 - L1	15 - L2	16 - L3		17 - S1.5	16 - S0.5	11 - R1.5
	TRENCHERS AND CABLE PLOWS																	
	RUBBER TIRED TRACTORS																	
	HEAVY CONSTRUCTION EQUIPMENT																	
	MOBILE CRANES																	
	FORKLIFTS																	
	TRAILERS WITH MOUNTED EQUIPMENT																	
	MISCELLANEOUS NON-HIGHWAY EQUPMENT																	
	MISCELLANEOUS EQUPMENT																	
	OTHER POWER OPERATED EQUIPMENT																	
	OFF ROAD POWER EQUIPMENT - SHORT LIFE																	
	OFF ROAD POWER EQUIPMENT - LONG LIFE																	
397	COMMUNICATION EQUIPMENT		15 - SQ	15 - SQ	10 - SQ	15 - SQ			15 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	10 - SQ	19 - S1.5	15 - SQ	15 - SQ	13 - L2
	COMPUTERS																	
	STRUCTURES & IMPROVEMENTS																	
	COMMUNICATION & CONTROL EQUIPMENT																	
	FIBER OPTIC CABLE																	
	SCADA																	
	TELEPHONE AND DATA COLLECTION EQUIPMENT																	
	TRANS LINE																	
	EMS																	
	MICROWAVE															15 - SQ		
	ELECTRONIC						10 - SQ	10 - SQ										
	TOWER/BUILDING						25 - SQ	25 - SQ										
	CLEARING																	
	MASSED																	
	OTHER																	
	REMOTE MONITORING EQUIPMENT																	
398	MISCELLANEOUS EQUIPMENT		15 - SQ	15 - SQ	15 - SQ		10 - SQ	10 - SQ		20 - SQ	20 - SQ	20 - SQ	20 - SQ	15 - SQ	20 - SQ	20 - SQ	10 - SQ	20 - SQ
399	OTHER TANGIBLE PROPERTY													5 - SQ				
	MINING EQUIPMENT																	

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 17 Survivor Curve	Company 18 Survivor Curve	Company 19 Survivor Curve	Company 20 Survivor Curve	Company 21 Survivor Curve	Company 22 Survivor Curve	Company 23 Survivor Curve	Company 24 Survivor Curve	Company 25 Survivor Curve	Company 26 Survivor Curve	Company 27 Survivor Curve	Company 28 Survivor Curve	Company 29 Survivor Curve	Company 30 Survivor Curve	Company 31 Survivor Curve	Company 32 Survivor Curve
	INTANGIBLE PLANT																	
302	FRANCHISES AND CONSENTS																	
303	MISCELLANEOUS INTANGIBLE PLANT			40 - SQ														
	SOFTWARE																	
	FIBER OPTIC																	
	5 YR											5 - SQ						
	10 YR											10 - SQ						
	15 YR											15 - SQ						
	25 YR											25 - SQ						
	RRSU UPGRADES																	
	STEAM PRODUCTION PLANT																	
310	LAND AND LAND RIGHTS - RIGHTS								75 - R4		75 - S4*		80 - R4*				75 - R4*	
	REMOVING OTHER PROPERTY																	
	EASEMENTS, PERMITS																	
311	STRUCTURES AND IMPROVEMENTS		80 - S0.5*						100 - R2.5*	70 - S0.5*	75 - S0*		75 - S0*	100 - R2.5*	100 - R2.5*		100 - S0.5*	
	LANDFILL																	
	SECURITY																	
312	BOILER PLANT EQUIPMENT		45 - S0.5*						55 - S0.5*	65 - R2.5*	50 - S0.5*		45 - S1.5	50 - L1*	45 - S1*		45 - S3*	
	COMBUSTION INITIATIVE													18 - SQ				
	UNIT COAL TRAIN													30 - S2.5*				
	POWER OPERATED																	
	UNCLASSIFIED																	
	SCRUBBERS																	
	FUEL EQUIPMENT																	
	COAL PILE BASE																	
	POLLUTION CONTROL EQUIPMENT		45 - S0.5*															
	RETROFIT PRECIPITATORS														50 - S1.5*			
	CATALYST														8 - S2.5			
	AQC																	
	CONTINUOUS EMISSION MONITORING																	
	TOOLS																	
	RAIL IMPROVEMENTS																	
313	ENGINES & GENERATORS																	
314	TURBOGENERATOR UNITS		55 - R1*						55 - R1.5*	60 - R3*	55 - S0*		60 - S1.5*	60 - S0.5*	52 - R2*		55 - S2.5*	
315	ACCESSORY ELECTRIC EQUIPMENT		50 - R1*						55 - R2.5*	35 - R3*	55 - R2.5*		50 - S1.5*	65 - R2*	55 - R2.5*		50 - S1.5*	
	COMBUSTION INITIATIVE																	
316	MISCELLANEOUS PLANT EQUIPMENT		25 - S1.5*						75 - R1*	45 - R3*	35 - R0.5*		55 - R2*	50 - S0*	55 - S0.5*		60 - R1.5*	
	COMBUSTION INITIATIVE																	
	AIR MONITORING EQUIPMENT																	
	FURNITURE																	
	DATA PROCESSING EQUIPMENT																	
	CARS																	
	TOOLS, SHOP AND GARAGE EQUIPMENT								37 - S0.5*									
	POWER OPERATED EQUIPMENT																	
	COMMUNICATION EQUIPMENT																	
	SMALL TRUCKS																	
	LARGE TRUCKS																	
	TRAILERS																	
	MISCELLANEOUS																	
	NUCLEAR PRODUCTION																	
320	LAND AND LAND RIGHTS - RIGHTS										100 - R4		75 - R4*				75 - R4*	
321	STRUCTURES AND IMPROVEMENTS										90 - R2.5*		75 - S0*				100 - S0.5*	
322	REACTOR PLANT EQUIPMENT										65 - R1.5*		55 - S0.5*				55 - R1.5	
	STEAM GENERATORS																	
323	TURBOGENERATOR UNITS										55 - R1*		50 - R1*				50 - R1.5*	
324	ACCESSORY ELECTRIC EQUIPMENT										50 - R2.5*		50 - S1.5*				50 - S1.5*	
325	MISCELLANEOUS PLANT EQUIPMENT										30 - S1*		55 - R2*				60 - R1.5*	
	HYDRAULIC PRODUCTION PLANT																	
330	LAND AND LAND RIGHTS - RIGHTS										100 - R4*		90 - R4*				90 - R4*	
	REMOVING PROPERTY OF OTHERS																	
331	STRUCTURES AND IMPROVEMENTS						65 - R3	100 - R2.5*		90 - S2*	95 - S1*		80 - R2.5*	100 - R3*			90 - R3*	
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
332	RESERVOIRS, DAMS AND WATERWAYS						75 - R4	90 - R3*		90 - S1.5*	100 - S1*		100 - L3*	75 - R3*			110 - L2.5*	
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
333	WATER WHEELS, TURBINES AND GENERATORS						60 - R3	90 - R1.5*		45 - S2.5*	45 - R1.5*		70 - S0.5*	60 - R3*			75 - S0.5*	
334	ACCESSORY ELECTRIC EQUIPMENT						50 - R1.5	45 - S0*		40 - S4*	40 - S0.5*		55 - L1.5*	55 - R3*			50 - L0.5*	
335	MISCELLANEOUS PLANT EQUIPMENT						45 - S2.5	60 - R3*		40 - R3*	60 - S0*		60 - R1.5*	50 - R3*			60 - R1.5*	
	EQUIPMENT																	

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 17 Survivor Curve	Company 18 Survivor Curve	Company 19 Survivor Curve	Company 20 Survivor Curve	Company 21 Survivor Curve	Company 22 Survivor Curve	Company 23 Survivor Curve	Company 24 Survivor Curve	Company 25 Survivor Curve	Company 26 Survivor Curve	Company 27 Survivor Curve	Company 28 Survivor Curve	Company 29 Survivor Curve	Company 30 Survivor Curve	Company 31 Survivor Curve	Company 32 Survivor Curve
	FURNITURE																	
	COMPUTER																	
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
336	ROADS, RAILROADS AND BRIDGES							55 - S3*		55 - S3*	75 - R3*		75 - R4*				65 - R2.5*	
	OTHER PRODUCTION PLANT																	
340	LAND AND LAND RIGHTS - RIGHTS								40 - SQ		SQUARE				40 - SQ			
341	STRUCTURES AND IMPROVEMENTS		40 - L1*				40 - S4	SQUARE*	SQUARE*	70 - S0.5*	60 - S1*		45 - S1.5*	60 - R4*	SQUARE*		SQUARE*	
	COMBINED CYCLE PRODUCTION																	
342	FUEL HOLDERS		50 - R4*				35 - S3	50 - R1.5*	SQUARE*	33 - S2*	60 - S2.5*		35 - S2.5*	60 - S2.5*	SQUARE*		SQUARE*	
	COMBINED CYCLE PRODUCTION																	
343	PRIME MOVERS		45 - R1*				25 - R4	50 - R2.5*	SQUARE*		60 - R2*		40 - R2.5*	50 - R2*	SQUARE*		SQUARE*	
	SOLAR													50 - R2*				
	WIND TURBINE													50 - R2*				
	FUEL CELLS																	
	BASE LOAD									12 - L0*								
	PEAKERS									31 - R3*								
	CONTINUOUS EMISSION MONITORING																	
	COMBINED CYCLE PRODUCTION																	
344	GENERATORS		40 - R1.5*				40 - S4	50 - S2.5*	70 - R2.5*	60 - R3*	65 - R2.5*		55 - R3*	50 - R3*	70 - R2.5*		SQUARE*	
	PORTABLE POWER MODULES																	
	SOLAR																	
	WIND																	
345	ACCESSORY ELECTRIC EQUIPMENT		35 - S1.5*				35 - R2.5	35 - R3*	55 - S0.5*	35 - R3*	40 - S1*		30 - L2*	45 - S2*	55 - S2*		SQUARE*	
	COMBINED CYCLE PRODUCTION																	
	WIND																	
346	MISCELLANEOUS PLANT EQUIPMENT		30 - R4*				30 - R2.5	45 - R3*	30 - S3*	45 - R3*	55 - O1*		35 - S2.5*	45 - R2*	40 - R2.5*		SQUARE*	
	COMBINED CYCLE PRODUCTION																	
	SOLAR PRODUCTION																	
	WIND																	
	A/V																	
348	EASEMENTS																	
	TRANSMISSION PLANT																	
350	LAND AND LAND RIGHTS - RIGHTS			30 - SQ		75 - R4	70 - R3					70 - R3	65 - R4	75 - R4	65 - R4	75 - S4	65 - R3	
351	EASEMENTS																	
352	STRUCTURES AND IMPROVEMENTS		60 - R4	65 - R2.5	45 - S2.5	55 - R4	65 - R3	60 - R3		50 - R3		50 - R4	50 - R3	75 - R4	55 - R3	60 - R3	43 - R3	
	MAJOR																	55 - R3*
	SMALL																	45 - R3
	NON SYS CONTROL/COM																	
	SYS CONTROL/COM																	
353	STATION EQUIPMENT		55 - R3	43 - S0.5	37 - R2	45 - R2	52 - R1	45 - S0.5		40 - S1.5		40 - R1	44 - R1.5	60 - R2	50 - R1.5	53 - R1	39 - R2.5	41 - S0
	STEP-UP TRANSFORMERS								55 - R1							55 - S4		
	STEP-UP EQUIPMENT															45 - S4		
	MISCELLANEOUS / OTHER															55 - R2.5		
	MICROWAVE									15 - SQ								
	SCADA									10 - SQ								
	SUPERVISORY EQUIPMENT						28 - S1											
	SUBSTATION ON CUSTOMER PREMISES																	
	PORTABLE PROPERTY AT SUBSTATIONS																	
	METERING STATION																	
	NON SYS CONTROL/COM																	
	SYS CONTROL/COM																	
	RTU															20 - S3		
	ELECTRONICS													20 - S2.5	15 - R2			
	MAJOR														45 - R2.5			
	COMMUNICATION EQUIPMENT																	
	SECURITY																	
	LEASEHOLD																	
354	TOWERS AND FIXTURES			70 - R3	55 - R3	64 - R3	65 - R3	42 - S1.5		65 - R3		70 - R4	55 - R2.5	70 - R3		80 - R3	48 - R4	70 - R3
	ROW CLEARING																	
355	POLES AND FIXTURES		55 - R2.5	55 - R2.5	50 - R2.5	29 - S1	50 - S0.5	48 - R2		40 - R2		55 - S2.5	45 - R2.5	55 - R1	50 - R1.5	55 - S0.5	40 - R3	50 - R2.5
	ROW CLEARING																	
	POLES AND FIXTURES - WOOD																	
	POLES AND FIXTURES - STEEL																	
	MINT LINE																	
	LEASEHOLD																	
356	OVERHEAD CONDUCTORS AND DEVICES		55 - R3	55 - R4	45 - R2.5	43 - R2.5	55 - S0.5	55 - R2.5		43 - R2.5		55 - R3	45 - R2.5	65 - R2	44 - R0.5	62 - R2.5	40 - R4	55 - R3
	ROW CLEARING						55 - S0.5											
	ON TOWERS						55 - S0.5											
	MINT LINE																	
357	UNDERGROUND CONDUIT		45 - R4		50 - R3	60 - R4	40 - R0.5			50 - R4		50 - S3	50 - S4	65 - R3		65 - R4	50 - R4	60 - R4
358	UNDERGROUND CONDUCTORS AND DEVICES		45 - R4	40 - S3	50 - R3	60 - R4	40 - R3			25 - S3		35 - S3	45 - S3	30 - R3		45 - R3	40 - R3	55 - R4
	SUB. CABLE - SOUTH									22 - L3								
	SUB. CABLE - NORTH									40 - S3								
359	ROADS AND TRAILS			75 - R3	55 - R3	75 - SQ		60 - R4		55 - R4		70 - R3	65 - R3					

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	DISTRIBUTION PLANT																
360	LAND & LAND RIGHTS - RIGHTS				75 - R4	60 - R3					70 - S4	65 - R3	70 - R4	70 - R3	75 - R3	65 - R3	
	EASEMENTS, SURVEYS AND CLEARING																
361	STRUCTURES AND IMPROVEMENTS	65 - R4			55 - R4	65 - R3	45 - S1.5		50 - R3		40 - S2.5	45 - R3	60 - R2.5	55 - R3	60 - R3	41 - R4	
	STRUCTURES AND IMPROVEMENTS - MAJOR																65 - R2.5*
	STRUCTURES AND IMPROVEMENTS - SMALL																45 - R3
	LEASEHOLD																
362	STATION EQUIPMENT	60 - R3			45 - R2	55 - R2	43 - R1		29 - S2		44 - R1	38 - R0.5	50 - R1.5	46 - R2	55 - R1.5	35 - R1.5	
	MAJOR													45 - R2.5	55 - R2.5		
	ELECTRONIC													15 - R2			
	SCADA								10 - SQ								
	COMPANY STATIONS																53 - R1
	CUSTOMER HIGH TENSION																40 - R0.5
	CONTROL CENTER																
	SUPERVISORY					30 - R2											
	TRANSFORMERS																
	OTHER																
	SECURITY																
	COMMUNICATION EQUIPMENT																
	LEASEHOLD																
	REMOTE MONITORING EQUIPMENT																
363	STORAGE BATTERY EQUIPMENT														20 - S3		
363.5	STATION EQUIPMENT - ELECTRONICS												20 - S2.5				
364	POLES, TOWERS AND FIXTURES	55 - R3			28 - R1.5	55 - R0.5	37 - R0.5		39 - R2.5		35 - R0.5	43 - R2	48 - R0.5	44 - R0.5	47 - R1	35 - R2.5	50 - R2
	POLES, TOWERS AND FIXTURES - WOOD POLES																
	POLES, TOWERS AND FIXTURES - STEEL TOWERS																
	CUSTOMER TRANSFORMER STATION																
	POLES																
	CLEARING TOWERS																
	CLEARING POLES																
	STEEL																
365	OVERHEAD CONDUCTORS AND DEVICES	55 - R2.5			30 - R1.5	60 - R1.5	41 - S0		35 - R2		42 - R2	40 - R0.5	48 - R0.5	44 - R1	50 - R1	32 - R1	48 - R1
	ROW CLEARING																
366	UNDERGROUND CONDUIT	60 - R3			55 - S1.5	65 - R3	40 - S1		55 - R3		60 - S2	45 - R3	65 - R3	65 - R3	65 - R3	42 - R3	70 - R4
	ENCASED																
	NOT ENCASED																
	UNDERGROUND CONDUIT - MANHOLES																
367	UNDERGROUND CONDUCTORS AND DEVICES	45 - R4			32 - R0.5	60 - R2.5	33 - L2		34 - R3		32 - R1	45 - R3	50 - R2.5	60 - R2	58 - R1.5	33 - R4	50 - R1.5
	CABLE INJECT								15 - S3								
	DUCT SYSTEM																
	DIRECT BURIED																
368	LINE TRANSFORMERS	44 - R3			28 - R1	43 - L1	33 - S0.5		32 - R3		35 - R4	36 - R1.5	40 - R1	35 - R1	40 - R1	32 - R1.5	
	TRANSFORMER INSTALLATIONS														40 - R0.5		
	OVERHEAD																40 - S0
	UNDERGROUND																
	PAD MOUNT																44 - R1
	NON-NETWORK HOUSING																
	NETWORK																50 - R1
	UNDERGROUND RESIDENTIAL DISTRIBUTION																40 - R1.5
	CUSTOMER													50 - R1.5			
369	SERVICES				26 - S2.5		34 - S0.5		40 - R1.5		35 - S2.5	38 - R1.5	40 - R0.5			30 - R1.5	65 - R3
	OVERHEAD	50 - R4				52 - R1.5							40 - R0.5	47 - R1	44 - R1.5		
	UNDERGROUND	45 - S4				52 - R1.5							40 - R0.5	55 - R2	60 - R1.5		
	UNDERGROUND CABLE																
370	METERS	45 - R2.5			27 - R2	30 - L0	29 - L0.5*		18 - S1.5		24 - L1	20 - L0	35 - S0.5	28 - S0	17 - L0.5	25 - O1	31 - R2.5*
	METER INSTALLATIONS																
	METERING DEVICES																
	AMR AND ELECTRONIC																10 - S3
	LOAD RESEARCH METERS	45 - R2.5															
	AMI METERS	15 - S2.5															
	IDAHO STANDARD																
	IDAHO AMR																
	WASHINGTON STANDARD																
371	INSTALLATIONS ON CUSTOMERS' PREMISES	35 - R1.5				22 - R0.5	16 - L0				25 - S2.5	35 - O1	16 - L0		15 - R2.5	24 - O1	
	AREA LIGHTING																
	PHOTOVOLTAIC INSTALLATIONS																
	LOAD CONTROL DEVICES																
372	LEASED PROPERTY					7 - S1.5								25 - L2	25 - L1		
373	STREET LIGHTING AND SIGNAL SYSTEMS	36 - R1			29 - R1.5	30 - R0.5	24 - O1		34 - R3		31 - S2.5	29 - S1	27 - R0.5		27 - L1	30 - R2.5	27 - R0.5
	MERCURY VAPOR																
	HIGH PRESSURE SODIUM																
	OVERHEAD													30 - L1			
	UNDERGROUND																
	TRANSFORMERS																
	BOULEVARD													30 - L1	40 - R1		
	CUSTOMER POLES													30 - R1	28 - O1		
	DUCK TO DAWN																
	NONROADWAY LIGHTING																
	CONDUIT AND CABLE																
	LAMPS AND EQUIPMENT																
	ELECTROLIERS																
375	EASEMENTS																

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	GENERAL PLANT																
389	LAND & LAND RIGHTS - RIGHTS		15 - SQ		55 - R4						65 - R4	60 - R3				40 - SQ	
390	STRUCTURES AND IMPROVEMENTS	60 - R2*	60 - R3		35 - R3	37 - R0.5	42 - R1.5		55 - R4			40 - R2.5		35 - R2.5		40 - R2	
	LEASEHOLD IMPROVEMENTS				20 - SQ	SQUARE	20 - SQ										
	LARGE					50 - O1			25 - S3		90 - S1.5*		60 - R1.5*		90 - R1		55 - R1.5*
	SMALL								45 - S3		40 - R2		50 - R3		45 - R3		45 - R3
	AIR CONDITIONING																
	PAD								30 - S3								
	LEASE																
	MISCELLANEOUS	50 - R3															
391	OFFICE FURNITURE & EQUIPMENT	20 - SQ			15 - SQ	15 - SQ			10 - SQ		15 - SQ	15 - SQ	20 - SQ	20 - SQ	20 - SQ	10 - SQ	
	FURNITURE		20 - SQ				15 - SQ										20 - SQ
	EQUIPMENT						10 - SQ										
	COMPUTERS AND SOFTWARE		5 - SQ			5 - SQ	5 - SQ		5 - SQ		5 - SQ					8 - SQ	
	COMPUTER HARDWARE	5 - SQ															
	SOFTWARE	5 - SQ	5 - SQ														
	LARGE APPLICATION SOFTWARE					10 - SQ											
	DATA HANDLING					10 - SQ	5 - SQ								5 - SQ		
	INFORMATION SYSTEMS												5 - SQ				
	AML&P - EKLUTNA																
	POWER MANAGEMENT SYSTEMS																
	CASH PROCESSING EQUIPMENT																
	EDP											8 - SQ					5 - SQ
	SYSTEM DEVELOPMENT	15 - SQ															
392	TRANSPORTATION EQUIPMENT		19 - S2.5			10 - L2.5	12 - R2.5				8.5 - L0.5		25 - S1.5		12 - L3		
	PASSENGER CARS & VANS	7 - L4			5 - S2				7 - S2.5			6 - L2.5				5 - R3	
	TRUCKS, TRAILERS AND VANS				10 - S1												
	LIGHT TRUCKS	7 - L5							10 - L4			7 - R3				6 - R3	
	MEDIUM TRUCKS	9 - L3										9 - R3				7 - R3	
	HEAVY TRUCKS	10 - L4							14 - S2			11 - R2.5				10 - R2	
	MEDIUM TRUCKS / POWER EQUIPPED											9 - R4					
	HEAVY TRUCKS / POWER EQUIPPED											11 - R2.5					
	AIRPLANES AND HELICOPTERS																
	AIRPLANES		11 - S2.5														
	HELICOPTERS		14 - R4										8 - S2.5				
	TRACTORS																
	TRAILERS	30 - L0.5										20 - L1.5		15 - SQ	20 - S1.5	17 - L1	
	MOTOR HOME																
	OTHER								12 - R2.5			12 - L3				12 - R3	
	SUBUNIT	15 - L4															
393	STORES EQUIPMENT	25 - SQ	30 - SQ		20 - SQ	25 - SQ	25 - SQ		20 - SQ		25 - SQ	20 - SQ	20 - SQ			10 - SQ	30 - SQ
394	TOOLS, SHOP AND GARAGE EQUIPMENT	25 - SQ	25 - SQ		25 - SQ	25 - SQ	20 - SQ		20 - SQ		25 - SQ	20 - SQ	25 - SQ	25 - SQ	25 - SQ	10 - SQ	25 - SQ
	ELECTRIC VEHICLES										10 - SQ						
395	LABORATORY EQUIPMENT	20 - SQ	15 - SQ		20 - SQ	20 - SQ	15 - SQ		20 - SQ		25 - SQ	15 - SQ	20 - SQ		15 - SQ	10 - SQ	20 - SQ
396	POWER OPERATED EQUIPMENT		21 - R1.5		14 - L2	12 - L3			14 - L2.5		10 - L1.5		22 - R0.5	14 - R3	17 - S0.5	15 - R3	20 - S0.5
	TRENCHERS AND CABLE PLOWS											12 - S1					
	RUBBER TIRED TRACTORS											12 - S1					
	HEAVY CONSTRUCTION EQUIPMENT											16 - R2.5					
	MOBILE CRANES											25 - S2					
	FORKLIFTS											15 - R3					
	TRAILERS WITH MOUNTED EQUIPMENT											17 - S2.5					
	MISCELLANEOUS NON-HIGHWAY EQUPMENT											14 - L2.5					
	MISCELLANEOUS EQUPMENT											14 - L2.5					
	OTHER POWER OPERATED EQUIPMENT																
	OFF ROAD POWER EQUIPMENT - SHORT LIFE	8 - L2															
	OFF ROAD POWER EQUIPMENT - LONG LIFE	25 - S0.5															
397	COMMUNICATION EQUIPMENT	15 - SQ	15 - SQ		15 - SQ	15 - SQ	10 - SQ				25 - SQ	10 - SQ	20 - SQ	15 - SQ	15 - SQ	10 - SQ	15 - SQ
	COMPUTERS				6 - SQ												
	STRUCTURES & IMPROVEMENTS																
	COMMUNICATION & CONTROL EQUIPMENT																
	FIBER OPTIC CABLE		25 - S2.5														
	SCADA								8 - SQ								
	TELEPHONE AND DATA COLLECTION EQUIPMENT					10 - SQ											
	TRANS LINE																
	EMS																
	MICROWAVE								15 - SQ								
	ELECTRONIC																
	TOWER/BUILDING		25 - S2				25 - SQ										
	CLEARING										15 - SQ						
	MASSED										15 - SQ						
	OTHER								10 - SQ								
	REMOTE MONITORING EQUIPMENT																
398	MISCELLANEOUS EQUIPMENT	20 - SQ	15 - SQ		15 - SQ	20 - SQ	15 - SQ		10 - SQ		25 - SQ	20 - SQ	15 - SQ		20 - SQ	10 - SQ	20 - SQ
399	OTHER TANGIBLE PROPERTY																
	MINING EQUIPMENT																

* Curve shown is interim survivor curve.

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FERC Acct.	Description	Client:	Company 33	Company 34	Company 35	Company 36	Company 37	Company 38	Company 39	Company 40	Company 41	Company 42	Company 43	Company 44	Company 45	Company 46	Company 47	Company 48
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	INTANGIBLE PLANT																	
302	FRANCHISES AND CONSENTS																	
303	MISCELLANEOUS INTANGIBLE PLANT									SQUARE								
	SOFTWARE																	
	FIBER OPTIC																	
	5 YR									5 - SQ								
	10 YR																	
	15 YR																	
	25 YR																	
	RRSU UPGRADES																	
	STEAM PRODUCTION PLANT																	
310	LAND AND LAND RIGHTS - RIGHTS					75 - R4*		70 - R5*							75 - R4*			
	REMOVING OTHER PROPERTY																	
	EASEMENTS, PERMITS																	
311	STRUCTURES AND IMPROVEMENTS		80 - S1	100 - S1.5*	100 - R2.5*	70 - R2*	75 - R2*	60 - R4*	65 - R2*	100 - S0*	55 - R2.5 *		85 - R1.5*	75 - R2.5*	100 - S1*		90 - S0.5*	90 - S0.5*
	LANDFILL																	
	SECURITY																	
312	BOILER PLANT EQUIPMENT		55 - S0.5	80 - S2.5*	75 - R2.5*	75 - R2.5*	60 - R1.5*	70 - R2.5*	55 - R2*	65 - S0.5*	40 - R2 *		65 - R1*	50 - S1*	60 - R1.5*		55 - R1*	55 - R1*
	COMBUSTION INITIATIVE																	
	UNIT COAL TRAIN														25 - R3		25 - R2.5	25 - R2.5
	POWER OPERATED																	
	UNCLASSIFIED																	
	SCRUBBERS														60 - R3*			
	FUEL EQUIPMENT																	
	COAL PILE BASE																	
	POLLUTION CONTROL EQUIPMENT												40 - R2.5*	50 - S1*				
	RETROFIT PRECIPITATORS																	
	CATALYST																	
	AQC																55 - R1*	55 - R1*
	CONTINUOUS EMISSION MONITORING																	
	TOOLS																	
	RAIL IMPROVEMENTS																	
313	ENGINES & GENERATORS			45 - R2.5*			60 - R2.5*											
314	TURBOGENERATOR UNITS		50 - S1	75 - R4*	60 - R2*	65 - R3*	60 - R1.5*	70 - R3*	50 - S2.5*	70 - R1.5*	40 - R1 *		70 - R1.5*	48 - S0.5*	45 - S1*		60 - R1.5*	60 - R1.5*
315	ACCESSORY ELECTRIC EQUIPMENT		60 - S2	65 - S1.5*	60 - R3*	60 - R2.5*	65 - R2*	70 - R2.5*	50 - S0.5*	80 - S0*	45 - R2.5 *		60 - S0.5*	50 - S0.5*	60 - S1.5*		50 - L1*	50 - L1*
	COMBUSTION INITIATIVE																	
316	MISCELLANEOUS PLANT EQUIPMENT		35 - R2	60 - R3*	55 - R2*	55 - R1.5*	50 - R1.5*	65 - R2*	50 - R1.5*	60 - R1.5*	40 - R2 *		30 - L1.5*	50 - R2*	45 - R0.5*		55 - L1*	55 - L1*
	COMBUSTION INITIATIVE																	
	AIR MONITORING EQUIPMENT																	
	FURNITURE																	
	DATA PROCESSING EQUIPMENT																	
	CARS														12 - L2			
	TOOLS, SHOP AND GARAGE EQUIPMENT																	
	POWER OPERATED EQUIPMENT														20 - O1			
	COMMUNICATION EQUIPMENT																	
	SMALL TRUCKS														12 - L2			
	LARGE TRUCKS														20 - L2			
	TRAILERS														35 - S1			
	MISCELLANEOUS														12 - L2			
	NUCLEAR PRODUCTION																	
320	LAND AND LAND RIGHTS - RIGHTS				70 - R3*		70 - R3*											
321	STRUCTURES AND IMPROVEMENTS				70 - R2.5*	90 - S1.5*	80 - R1.5*			100 - R1.5*	40 - R3 *						90 - S0.5*	90 - S0.5*
322	REACTOR PLANT EQUIPMENT				40 - R1.5*	60 - R1.5*	60 - R2.5*			65 - S0.5*	45 - R2.5 *						60 - R2*	60 - R2*
	STEAM GENERATORS																	
323	TURBOGENERATOR UNITS				50 - R3*	50 - S0.5*	55 - S0.5*			40 - R2.5*	35 - R1 *						50 - S1.5*	50 - S1.5*
324	ACCESSORY ELECTRIC EQUIPMENT				60 - R3*	60 - S1.5*	50 - S2.5*			55 - R2*	45 - R3 *						50 - S1.5*	50 - S1.5*
325	MISCELLANEOUS PLANT EQUIPMENT				50 - R3*	50 - R2*	55 - S0.5*			55 - S0*	55 - R2.5 *						40 - R0.5*	40 - R0.5*
	HYDRAULIC PRODUCTION PLANT																	
330	LAND AND LAND RIGHTS - RIGHTS				75 - R3													
	REMOVING PROPERTY OF OTHERS																	
331	STRUCTURES AND IMPROVEMENTS				100 - S2.5*					100 - R1*					105 - R2.5*			
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
332	RESERVOIRS, DAMS AND WATERWAYS				100 - S2.5*					110 - R1.5*					95 - S4*			
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
333	WATER WHEELS, TURBINES AND GENERATORS				90 - S4*					80 - L2*					80 - R3*			
334	ACCESSORY ELECTRIC EQUIPMENT				45 - R2.5*				45 - S3*	55 - R1.5*					50 - R1.5*			
335	MISCELLANEOUS PLANT EQUIPMENT				60 - R2.5*				40 - R2.5*	60 - S1*					95 - R2*			
	EQUIPMENT														15 - SQ			

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 33	Company 34	Company 35	Company 36	Company 37	Company 38	Company 39	Company 40	Company 41	Company 42	Company 43	Company 44	Company 45	Company 46	Company 47	Company 48
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	FURNITURE														20 - SQ			
	COMPUTER														5 - SQ			
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
336	ROADS, RAILROADS AND BRIDGES									100 - S0.5*					75 - R3*			
	OTHER PRODUCTION PLANT																	
340	LAND AND LAND RIGHTS - RIGHTS																	
341	STRUCTURES AND IMPROVEMENTS		SQUARE*	SQUARE*	50 - S1.5*		50 - S1.5*	50 - S1.5*		85 - R1*	25 - R5 *		50 - R5*	60 - R1*	SQUARE*		60 - R1*	60 - R1*
	COMBINED CYCLE PRODUCTION																	
342	FUEL HOLDERS		SQUARE*	SQUARE*	55 - S2*		50 - R3*	55 - S2*		60 - S0*	22 - R3 *		40 - S3*	45 - R2*	50 - S2.5*		45 - R2*	45 - R2*
	COMBINED CYCLE PRODUCTION																	
343	PRIME MOVERS		SQUARE*		45 - S1.5*	45 - S1.5*	35 - R3*	45 - S1.5*			50 - R1 *		55 - R1*	25 - S0.5*	40 - S1.5*			
	SOLAR																	
	WIND TURBINE																	
	FUEL CELLS																	
	BASE LOAD																	
	PEAKERS																	
	CONTINUOUS EMISSION MONITORING																	
	COMBINED CYCLE PRODUCTION																	
344	GENERATORS		SQUARE*	SQUARE*	40 - S1.5*	40 - S1.5*	40 - R2.5*	40 - S1.5*		50 - R3*	30 - R5 *		50 - R2.5*	35 - S0.5*	45 - S2*		35 - S0.5*	35 - S0.5*
	PORTABLE POWER MODULES																	
	SOLAR																	
	WIND																	
345	ACCESSORY ELECTRIC EQUIPMENT		SQUARE*	SQUARE*	45 - S2.5*		35 - R1*	45 - S2.5*		65 - R2*	28 - R4 *		45 - R4*	45 - R2.5*	50 - S1.5*		45 - R2.5*	45 - R2.5*
	COMBINED CYCLE PRODUCTION																	
	WIND																	
346	MISCELLANEOUS PLANT EQUIPMENT		SQUARE*	SQUARE*	35 - R2.5*	35 - R2.5*	30 - S1.5*	35 - S2.5*		35 - R2.5*	22 - R4 *			32 - S2*	35 - R2.5*			
	COMBINED CYCLE PRODUCTION																	
	SOLAR PRODUCTION																	
	WIND																	
	A/V																	
348	EASEMENTS																	
	TRANSMISSION PLANT																	
350	LAND AND LAND RIGHTS - RIGHTS			70 - R4	75 - R3	65 - R4	70 - R4	75 - R3	65 - R4		50 - S4				70 - R3			
351	EASEMENTS																	
352	STRUCTURES AND IMPROVEMENTS			55 - S3	55 - R3	60 - S2.5	55 - S1.5	70 - R4	50 - R2.5	50 - R5*	60 - R3		60 - R4	60 - R3	65 - R3		60 - R2.5	60 - R2.5
	MAJOR																	
	SMALL																	
	NON SYS CONTROL/COM																	
	SYS CONTROL/COM																	
353	STATION EQUIPMENT		40 - R3	45 - R3	51 - R2	55 - R2	50 - R2	59 - R2	45 - R2.5	55 - S1*	38 - R1.5		36 - R2	58 - R2	48 - R1.5		60 - R0.5	60 - R0.5
	STEP-UP TRANSFORMERS										33 - R2							
	STEP-UP EQUIPMENT																	
	MISCELLANEOUS / OTHER																	
	MICROWAVE																	
	SCADA																	
	SUPERVISORY EQUIPMENT																	
	SUBSTATION ON CUSTOMER PREMISES																	
	PORTABLE PROPERTY AT SUBSTATIONS																	
	METERING STATION																	
	NON SYS CONTROL/COM																	
	SYS CONTROL/COM																	
	RTU																	
	ELECTRONICS																	
	MAJOR																	
	COMMUNICATION EQUIPMENT																15 - S2.5	15 - S2.5
	SECURITY																	
	LEASEHOLD																	
354	TOWERS AND FIXTURES		65 - R3	65 - R4	65 - R4	55 - R4	50 - R2.5	65 - R2.5	50 - S4	60 - R2.5*	40 - R5			55 - R3	65 - S3		70 - R3	70 - R3
	ROW CLEARING																	
355	POLES AND FIXTURES		50 - R2.5	40 - S4	50 - R1.5	52 - R1.5	60 - R2.5	58 - R2	55 - R3		44 - R2		60 - R2	53 - S0.5	60 - R2		50 - S0.5	50 - S0.5
	ROW CLEARING																	
	POLES AND FIXTURES - WOOD																	
	POLES AND FIXTURES - STEEL																	
	MINT LINE																	
	LEASEHOLD																	
356	OVERHEAD CONDUCTORS AND DEVICES		50 - S2	50 - R5	60 - R2.5	60 - R2.5	60 - R2.5	72 - R2	53 - R2.5	55 - R3*	47 - R1.5		60 - R2	62 - R2.5	65 - R2		53 - R2	53 - R2
	ROW CLEARING																	
	ON TOWERS																	
	MINT LINE																	
357	UNDERGROUND CONDUIT				50 - S2.5	50 - S2.5	50 - S2.5	50 - S2.5		60 - R2*	60 - R4		60 - R3				60 - R3	60 - R3
358	UNDERGROUND CONDUCTORS AND DEVICES				45 - R2.5	45 - S2.5	45 - S2.5	45 - S2.5	40 - R2.5	60 - R2*	60 - L3		50 - S3	50 - R3			55 - R4	55 - R4
	SUB. CABLE - SOUTH																	
	SUB. CABLE - NORTH																	
359	ROADS AND TRAILS		60 - R4	50 - R3	75 - R3	60 - R1.5	60 - R4		65 - R4		50 - SQ				65 - R2.5			

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 33	Company 34	Company 35	Company 36	Company 37	Company 38	Company 39	Company 40	Company 41	Company 42	Company 43	Company 44	Company 45	Company 46	Company 47	Company 48
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	DISTRIBUTION PLANT																	
360	LAND & LAND RIGHTS - RIGHTS			70 - R4	65 - R4	65 - R4	70 - R4	65 - R4	55 - R4									
	EASEMENTS, SURVEYS AND CLEARING																	
361	STRUCTURES AND IMPROVEMENTS			55 - R4	55 - R3	60 - R2.5	60 - R2	60 - R4	50 - S1.5	50 - R2.5	60 - R3		50 - R3	60 - R3	65 - R2.5		50 - S0.5	50 - S0.5
	STRUCTURES AND IMPROVEMENTS - MAJOR																	
	STRUCTURES AND IMPROVEMENTS - SMALL																	
	LEASEHOLD																	
362	STATION EQUIPMENT		30 - R3	50 - R3	54 - R1.5	50 - S0	55 - R1	61 - R2	40 - R1.5	45 - R2.5	41 - R1.5		50 - R2.5	50 - R1	50 - R1	15 - S3	48 - R1.5	48 - R1.5
	MAJOR																	
	ELECTRONIC																	
	SCADA																	
	COMPANY STATIONS																	
	CUSTOMER HIGH TENSION																	
	CONTROL CENTER																	
	SUPERVISORY																	
	TRANSFORMERS																	
	OTHER																	
	SECURITY																	
	COMMUNICATION EQUIPMENT																15 - S2.5	15 - S2.5
	LEASEHOLD																	
	REMOTE MONITORING EQUIPMENT																	
363	STORAGE BATTERY EQUIPMENT																	
363.5	STATION EQUIPMENT - ELECTRONICS																	
364	POLES, TOWERS AND FIXTURES			42 - R3	35 - R0.5	33 - O1	32 - R0.5	30 - R0.5	40 - S0.5	53 - R2	37 - R2		52 - S2.5	47 - R4	44 - R1.5	29 - L1.5	38 - R3	38 - R3
	POLES, TOWERS AND FIXTURES - WOOD POLES																	
	POLES, TOWERS AND FIXTURES - STEEL TOWERS																	
	CUSTOMER TRANSFORMER STATION																	
	POLES																	
	CLEARING TOWERS																	
	CLEARING POLES																	
	STEEL																	
365	OVERHEAD CONDUCTORS AND DEVICES			45 - R2.5	34 - R0.5	37 - O1	37 - R1	35 - R0.5	36 - R0.5	52 - R2.5	40 - S0		55 - R1	58 - R1.5	45 - R0.5	31 - R1	45 - R0.5	45 - R0.5
	ROW CLEARING																	
366	UNDERGROUND CONDUIT			50 - R3	35 - R2	50 - R2	48 - R1.5	52 - R2	50 - R2				65 - R3	60 - S1	60 - R2	50 - S2	55 - R2	55 - R2
	ENCASED										70 - S1.5							
	NOT ENCASED										50 - R4							
	UNDERGROUND CONDUIT - MANHOLES																	
367	UNDERGROUND CONDUCTORS AND DEVICES			36 - R2.5	31 - S2	37 - R1.5	39 - R1	50 - R1	37 - S0.5				55 - R2	50 - S1.5	46 - R2	30 - R2	50 - R1.5	50 - R1.5
	CABLE INJECT																	
	DUCT SYSTEM										38 - S0							
	DIRECT BURIED										35 - R2							
368	LINE TRANSFORMERS		40 - R2.5	50 - R3	28 - R0.5	33 - S0	25 - L0	25 - R1.5	29 - S0		32 - L1.5		45 - R2.5	35 - R2	35 - R1	39 - R1	34 - R2	34 - R2
	TRANSFORMER INSTALLATIONS																	
	OVERHEAD																	
	UNDERGROUND																	
	PAD MOUNT																	
	NON-NETWORK HOUSING																	
	NETWORK																	
	UNDERGROUND RESIDENTIAL DISTRIBUTION																	
	CUSTOMER																	
369	SERVICES			55 - S3											40 - R2	28 - R0.5	48 - R2.5	48 - R2.5
	OVERHEAD				42 - S2	33 - R4	34 - S0.5	36 - S0	27 - L4		48 R1		57 - R4	57 - R4				
	UNDERGROUND				35 - S2.5	33 - R4	36 - S0.5	36 - S0	27 - L4		34 - R2		40 - S4	38 - R5				
	UNDERGROUND CABLE																	
370	METERS			27 - R2	29 - R1	32 - R1.5	36 - R1	32 - R1	29 - R2		36 - R2.5		50 - S1.5	45 - R2.5	22 - O1	24 - R2	36 - R1.5	36 - R1.5
	METER INSTALLATIONS																	
	METERING DEVICES																	
	AMR AND ELECTRONIC										20 - R2.5				15 - S2.5	15 - S3		
	LOAD RESEARCH METERS													16 - S4				
	AMI METERS																	
	IDAHO STANDARD																	
	IDAHO AMR																	
	WASHINGTON STANDARD																	
371	INSTALLATIONS ON CUSTOMERS' PREMISES			32 - R1.5	15 - L2	50 - R2.5	20 - S0	35 - L0	40 - S2.5		30 - L0		26 - O1	29 - R1.5	17 - R1.5	21 - R1	20 - L1.5	20 - L1.5
	AREA LIGHTING																	
	PHOTOVOLTAIC INSTALLATIONS														12 - S4			
	LOAD CONTROL DEVICES																	
372	LEASED PROPERTY																	
373	STREET LIGHTING AND SIGNAL SYSTEMS			50 - R2.5	19 - R0.5	43 - R2	25 - L0	17 - L0	46 - R1.5		30 - R0.5		35 - R0.5	26 - S0	30 - R1	21 - R1	25 - L0.5	25 - L0.5
	MERCURY VAPOR																	
	HIGH PRESSURE SODIUM																	
	OVERHEAD																	
	UNDERGROUND																	
	TRANSFORMERS																	
	BOULEVARD																	
	CUSTOMER POLES																	
	DUCK TO DAWN																	
	NONROADWAY LIGHTING					45 - R2	30 - R2		40 - S0.5									
	CONDUIT AND CABLE																	
	LAMPS AND EQUIPMENT																	
	ELECTROLIERS																	
375	EASEMENTS																	

Service Life and Net Salvage Statistics - US - Electric

	Client:	Company 33	Company 34	Company 35	Company 36	Company 37	Company 38	Company 39	Company 40	Company 41	Company 42	Company 43	Company 44	Company 45	Company 46	Company 47	Company 48
FERC Acct.	Description	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	GENERAL PLANT																
389	LAND & LAND RIGHTS - RIGHTS						60 - R4										
390	STRUCTURES AND IMPROVEMENTS			50 - R1.5	55 - S1.5	45 - R2.5	46 - S1	44 - R2.5	50 - R1	50 - R1.5	45 - R1.5	45 - R1.5	45 - R2.5		45 - SQ	45 - R1	45 - R1
	LEASEHOLD IMPROVEMENTS													35 - S3			
	LARGE	SQUARE*	80 - S1.5*											100 - S0.5*	75 - R2.5		
	SMALL	40 - SQ	45 - R1.5											55 - S0.5*			
	AIR CONDITIONING																
	PAD																
	LEASE																
	MISCELLANEOUS																
391	OFFICE FURNITURE & EQUIPMENT	15 - SQ	20 - SQ	20 - SQ	15 - SQ	15 - SQ	20 - SQ	15 - SQ	15 - SQ		20 - SQ	20 - SQ	20 - SQ			20 - SQ	20 - SQ
	FURNITURE													20 - SQ	25 - SQ		
	EQUIPMENT								10 - SQ			10 - SQ		5 - SQ	5 - SQ		
	COMPUTERS AND SOFTWARE								5 - SQ		5 - SQ	5 - SQ	5 - SQ	8 - L2	5 - SQ	5 - SQ	5 - SQ
	COMPUTER HARDWARE																
	SOFTWARE										7 - SQ	7 - SQ	7 - SQ		10 - SQ		
	LARGE APPLICATION SOFTWARE																
	DATA HANDLING			15 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ									
	INFORMATION SYSTEMS			5 - SQ	5 - SQ	5 - SQ	5 - SQ	5 - SQ									
	AML&P - EKLUTNA																
	POWER MANAGEMENT SYSTEMS																
	CASH PROCESSING EQUIPMENT																
	EDP																
	SYSTEM DEVELOPMENT																
392	TRANSPORTATION EQUIPMENT	9 - R0.5		15 - R3	13 - S1	8 - L2.5	11 - S1	8 - L0									
	PASSENGER CARS & VANS								8 - R3	6 - L2		7 - S4	9 - S3	12 - L2	5 - S3	7 - R2	7 - R2
	TRUCKS, TRAILERS AND VANS																
	LIGHT TRUCKS								10 - R4	9 - L3		10 - S4	9 - S3	12 - L2	7 - R3	8 - R0.5	8 - R0.5
	MEDIUM TRUCKS											11 - S3	10 - S3				
	HEAVY TRUCKS								13 - R5	12 - S3		12 - L3	12 - L3	20 - L2	10 - L2	10 - S1.5	10 - S1.5
	MEDIUM TRUCKS / POWER EQUIPPED																
	HEAVY TRUCKS / POWER EQUIPPED																
	AIRPLANES AND HELICOPTERS													10 - S2.5			
	AIRPLANES									7 - SQ							
	HELICOPTERS									7 - SQ							
	TRACTORS									9 - L2.5						12 - S0	12 - S0
	TRAILERS									20 - L1.5		25 - R3	17 - R2	35 - S1		20 - S1.5	20 - S1.5
	MOTOR HOME																
	OTHER													12 - L2			
	SUBUNIT																
393	STORES EQUIPMENT	20 - SQ	25 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ				25 - SQ	25 - SQ	25 - SQ	20 - SQ	25 - SQ	25 - SQ
394	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	25 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ	20 - SQ		20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ
	ELECTRIC VEHICLES																
395	LABORATORY EQUIPMENT	20 - SQ	15 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	15 - SQ			20 - SQ	20 - SQ	20 - SQ	15 - SQ	20 - SQ	20 - SQ
396	POWER OPERATED EQUIPMENT	16 - R0.5	20 - R2	15 - L2.5	20 - R2	25 - L4	30 - R2.5	16 - S0		10 - L0.5		19 - S1.5	22 - S1.5	20 - O1	10 - S3	13 - L2	13 - L2
	TRENCHERS AND CABLE PLOWS																
	RUBBER TIRED TRACTORS																
	HEAVY CONSTRUCTION EQUIPMENT																
	MOBILE CRANES																
	FORKLIFTS																
	TRAILERS WITH MOUNTED EQUIPMENT																
	MISCELLANEOUS NON-HIGHWAY EQUPMENT																
	MISCELLANEOUS EQUPMENT																
	OTHER POWER OPERATED EQUIPMENT									9 - L0.5							
	OFF ROAD POWER EQUIPMENT - SHORT LIFE																
	OFF ROAD POWER EQUIPMENT - LONG LIFE																
397	COMMUNICATION EQUIPMENT	10 - SQ	15 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	20 - SQ		15 - SQ	15 - SQ	15 - SQ	15 - SQ	10 - SQ	15 - SQ	15 - SQ
	COMPUTERS																
	STRUCTURES & IMPROVEMENTS																
	COMMUNICATION & CONTROL EQUIPMENT																
	FIBER OPTIC CABLE									10 - L0				10 - SQ			
	SCADA																
	TELEPHONE AND DATA COLLECTION EQUIPMENT																
	TRANS LINE																
	EMS																
	MICROWAVE			15 - SQ	15 - SQ	15 - SQ	15 - SQ	15 - SQ									
	ELECTRONIC																
	TOWER/BUILDING																
	CLEARING																
	MASSED																
	OTHER																
	REMOTE MONITORING EQUIPMENT																
398	MISCELLANEOUS EQUIPMENT	15 - SQ	15 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	10 - SQ	15 - SQ		20 - SQ	20 - SQ		15 - SQ	15 - SQ	20 - SQ	20 - SQ
399	OTHER TANGIBLE PROPERTY			40 - R2.5			40 - R2.5										
	MINING EQUIPMENT																

* Curve shown is interim survivor curve.

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FERC Acct.	Description	Client:	Company 49	Company 50	Company 51	Company 52	Company 53	Company 54	Company 55	Company 56	Company 57	Company 58	Company 59	Company 60	Company 61	Company 62	Company 63	Company 64
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	INTANGIBLE PLANT																	
302	FRANCHISES AND CONSENTS														10 - SQ	10 - SQ	25 - SQ	
303	MISCELLANEOUS INTANGIBLE PLANT								7 - SQ						5 - SQ	5 - SQ	3 - SQ	
	SOFTWARE											10 - SQ			10 - SQ	10 - SQ	3 - SQ	5 - SQ
	FIBER OPTIC														15 - SQ	15 - SQ		
	5 YR																	
	10 YR																	
	15 YR																	
	25 YR																	
	RRSU UPGRADES											35 - SQ						
	STEAM PRODUCTION PLANT													60 - L2*				
310	LAND AND LAND RIGHTS - RIGHTS											SQUARE*					100 - S4*	
	REMOVING OTHER PROPERTY																	
	EASEMENTS, PERMITS																	
311	STRUCTURES AND IMPROVEMENTS		100 - S1.5	100 - S1.5*	90 - R2*		120 - S0*	SQUARE*			110 - R2.5*	75 - L1*	100 - R2.5*				100 - R2.5*	
	LANDFILL																	
	SECURITY																10 - SQ	
312	BOILER PLANT EQUIPMENT		65 - R2	45 - R1.5*	75 - R2.5*		60 - S0*	SQUARE*			65 - R1*	75 - R1.5*	45 - S0.5*				90 - R1.5*	
	COMBUSTION INITIATIVE																	
	UNIT COAL TRAIN			25 - R2							25 - R2.5*		25 - R2.5					
	POWER OPERATED																	
	UNCLASSIFIED																	
	SCRUBBERS																	
	FUEL EQUIPMENT																	
	COAL PILE BASE												SQUARE*					
	POLLUTION CONTROL EQUIPMENT																	
	RETROFIT PRECIPITATORS																	
	CATALYST																	
	AQC																	
	CONTINUOUS EMISSION MONITORING																10 - SQ	
	TOOLS																	
	RAIL IMPROVEMENTS																	
313	ENGINES & GENERATORS																	
314	TURBOGENERATOR UNITS		55 - R2.5	50 - S1.5*	60 - R2.5*		100 - S0*	SQUARE*			75 - R1.5*	80 - R1*	50 - S1.5*				50 - R1*	
315	ACCESSORY ELECTRIC EQUIPMENT		70 - S3	50 - S2*	65 - R2*		80 - R2*	SQUARE*			65 - R1.5*	75 - R2.5*	55 - S0.5*				65 - S2*	
	COMBUSTION INITIATIVE																	
316	MISCELLANEOUS PLANT EQUIPMENT		70 - R1.5	40 - S2*	45 - R1.5*		70 - L0*	20 - SQ			50 - R2*	40 - O1*	55 - R2*				50 - R1.5*	
	COMBUSTION INITIATIVE																	
	AIR MONITORING EQUIPMENT																	
	FURNITURE																	
	DATA PROCESSING EQUIPMENT																	
	CARS																	
	TOOLS, SHOP AND GARAGE EQUIPMENT																	
	POWER OPERATED EQUIPMENT																	
	COMMUNICATION EQUIPMENT																	
	SMALL TRUCKS																	
	LARGE TRUCKS																	
	TRAILERS																	
	MISCELLANEOUS																	
	NUCLEAR PRODUCTION																	
320	LAND AND LAND RIGHTS - RIGHTS																	
321	STRUCTURES AND IMPROVEMENTS																	
322	REACTOR PLANT EQUIPMENT																	
	STEAM GENERATORS																	
323	TURBOGENERATOR UNITS																	
324	ACCESSORY ELECTRIC EQUIPMENT																	
325	MISCELLANEOUS PLANT EQUIPMENT																	
	HYDRAULIC PRODUCTION PLANT													95 - S1.5*				
330	LAND AND LAND RIGHTS - RIGHTS		100 - R4															
	REMOVING PROPERTY OF OTHERS																	
331	STRUCTURES AND IMPROVEMENTS		90 - S2.5	100 - S2.5*							100 - S1*		75 - R2.5*					
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
332	RESERVOIRS, DAMS AND WATERWAYS		100 - S2.5	100 - S2.5*							100 - S1*		100 - R2.5*					
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
333	WATER WHEELS, TURBINES AND GENERATORS		80 - R3	100 - S2.5*							75 - S2.5*		70 - R2.5*					
334	ACCESSORY ELECTRIC EQUIPMENT		40 - L2.5	80 - S4*							60 - S1.5*		50 - L1.5*					
335	MISCELLANEOUS PLANT EQUIPMENT		35 - L1	80 - S3*							45 - R2.5*		45 - L1.5*					
	EQUIPMENT																	

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 49	Company 50	Company 51	Company 52	Company 53	Company 54	Company 55	Company 56	Company 57	Company 58	Company 59	Company 60	Company 61	Company 62	Company 63	Company 64
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	FURNITURE																	
	COMPUTER																	
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
336	ROADS, RAILROADS AND BRIDGES		55 - R4	80 - S4*														
	OTHER PRODUCTION PLANT													90 - S0.5*				
340	LAND AND LAND RIGHTS - RIGHTS		30 - R0.5								75 - R3*	200 - SQ*						
341	STRUCTURES AND IMPROVEMENTS		40 - R2.5	55 - R3*	45 - R2.5*		70 - S0*	SQUARE*			60 - R4*	75 - L0*	45 - S3*				50 - S3*	
	COMBINED CYCLE PRODUCTION																	
342	FUEL HOLDERS		45 - R2.5	50 - R3*	55 - R3*			SQUARE*			50 - S3*	50 - S0*	50 - S2.5*				55 - R4*	
	COMBINED CYCLE PRODUCTION																	
343	PRIME MOVERS		35 - R1	30 - R2*	60 - R3*			SQUARE*			45 - S3*	40 - R2.5*	45 - R3*				30 - R3*	
	SOLAR																	
	WIND TURBINE													SQUARE*				
	FUEL CELLS																	
	BASE LOAD																	
	PEAKERS																	
	CONTINUOUS EMISSION MONITORING																10 - SQ	
	COMBINED CYCLE PRODUCTION																	
344	GENERATORS		55 - S3	60 - S3*	55 - S2*		70 - S1	SQUARE*			55 - R3*	40 - R2.5*	50 - R2.5*				45 - R3*	
	PORTABLE POWER MODULES										55 - R3*							
	SOLAR																	
	WIND																	
345	ACCESSORY ELECTRIC EQUIPMENT		45 - R3	35 - S1.5*	50 - S3*			SQUARE*			50 - R2.5*	45 - R2.5*	35 - S3*				25 - S2*	
	COMBINED CYCLE PRODUCTION																	
	WIND										50 - S4*							
346	MISCELLANEOUS PLANT EQUIPMENT		35 - R2	50 - S3*	30 - R1.5*		SQUARE*	20 - SQ			40 - S2*	40 - O1*	50 - R3*				30 - R2.5*	
	COMBINED CYCLE PRODUCTION																	
	SOLAR PRODUCTION																	
	WIND										40 - S2.5*							
	A/V																	
348	EASEMENTS																	
	TRANSMISSION PLANT																	
350	LAND AND LAND RIGHTS - RIGHTS		60 - R3	50 - R3		80 - SQ	70 - R5	60 - R5	80 - SQ	75 - R3	70 - R4	65 - R4	65 - R4				75 - R4	
351	EASEMENTS													80 - SQ				
352	STRUCTURES AND IMPROVEMENTS			60 - R2.5		50 - R1.5		50 - R4	55 - R3	60 - R4	60 - R3	50 - R3	50 - R1.5		55 - S2.5	55 - S2.5	65 - R2.5	
	MAJOR																	
	SMALL																	
	NON SYS CONTROL/COM		65 - S2.5															
	SYS CONTROL/COM		60 - R3															
353	STATION EQUIPMENT			55 - R2.5		55 - R2	48 - R3	55 - R4	46 - R2	50 - R2	55 - R1.5	54 - R2.5	43 - S0	42 - R2.5	40 - R2	40 - R2	55 - R2	
	STEP-UP TRANSFORMERS																40 - R2.5	
	STEP-UP EQUIPMENT																	
	MISCELLANEOUS / OTHER																	
	MICROWAVE																	
	SCADA																	
	SUPERVISORY EQUIPMENT																	
	SUBSTATION ON CUSTOMER PREMISES																	
	PORTABLE PROPERTY AT SUBSTATIONS																	
	METERING STATION																	
	NON SYS CONTROL/COM		60 - R2															
	SYS CONTROL/COM		30 - R2.5															
	RTU																	
	ELECTRONICS																	
	MAJOR																	
	COMMUNICATION EQUIPMENT																	
	SECURITY																10 - SQ	
	LEASEHOLD																	
354	TOWERS AND FIXTURES		70 - R4	65 - R3			60 - R4	50 - R2	65 - R3	65 - R3	70 - S2.5	60 - R4	60 - R4	55 - S3	65 - R3	65 - R3	75 - R4	
	ROW CLEARING									75 - R3								
355	POLES AND FIXTURES		50 - R2	50 - R2		55 - R3	46 - R2	50 - R2	55 - R2.5	55 - R2.5	52 - R2.5	45 - R2	52 - R1.5	47 - R2	50 - R3	50 - R3	55 - R1	
	ROW CLEARING					80 - SQ				70 - R5								
	POLES AND FIXTURES - WOOD																	
	POLES AND FIXTURES - STEEL																	
	MINT LINE																	
	LEASEHOLD																	
356	OVERHEAD CONDUCTORS AND DEVICES		60 - R3	50 - R2		50 - R3	48 - R2.5	47 - R1.5	60 - R2	55 - R3	55 - R3	55 - R1.5	55 - R2.5	45 - R3	50 - R3	50 - R3	60 - R2.5	
	ROW CLEARING								80 - SQ									
	ON TOWERS																	
	MINT LINE																	
357	UNDERGROUND CONDUIT		40 - L2.5	50 - R3				60 - R3			55 - R4	55 - R2	55 - S3	65 - S3	50 - S3	50 - S3		
358	UNDERGROUND CONDUCTORS AND DEVICES		35 - R3	30 - R3				50 - R3			55 - R4	45 - R3	40 - R1	40 - R4	50 - S4	50 - S4	40 - R2.5	
	SUB. CABLE - SOUTH																	
	SUB. CABLE - NORTH																	
359	ROADS AND TRAILS								50 - SQ	75 - R3	70 - R4	60 - R5	60 - R5	65 - SQ	55 - R4	55 - R4		

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 49	Company 50	Company 51	Company 52	Company 53	Company 54	Company 55	Company 56	Company 57	Company 58	Company 59	Company 60	Company 61	Company 62	Company 63	Company 64
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	DISTRIBUTION PLANT																	
360	LAND & LAND RIGHTS - RIGHTS		65 - R4			80 - SQ	70 - R5	50 - R5	65 - SQ		70 - R4	65 - R4	65 - R4				65 - S4	
	EASEMENTS, SURVEYS AND CLEARING													60 - SQ				
361	STRUCTURES AND IMPROVEMENTS		60 - R2.5	60 - R3	60 - R2.5	45 - R3		50 - R3	45 - R3		65 - R3	50 - R3	50 - R1.5	50 - R2.5	55 - R2.5	55 - R2.5	60 - R2	
	STRUCTURES AND IMPROVEMENTS - MAJOR																	
	STRUCTURES AND IMPROVEMENTS - SMALL																	
	LEASEHOLD																	
362	STATION EQUIPMENT		52 - R2	55 - R1.5	55 - R1.5	47 - R2	46 - R3	55 - R3	55 - R2		55 - R2.5	50 - R2.5	45 - S0.5	48 - R1.5	45 - R2.5	45 - R2.5	55 - R2.5	
	MAJOR																	
	ELECTRONIC																	
	SCADA													14 - R2.5				
	COMPANY STATIONS																	
	CUSTOMER HIGH TENSION																	
	CONTROL CENTER																	
	SUPERVISORY																	
	TRANSFORMERS																40 - R2.5	
	OTHER													14 - R2.5				
	SECURITY																10 - SQ	
	COMMUNICATION EQUIPMENT																	
	LEASEHOLD																	
	REMOTE MONITORING EQUIPMENT													14 - R2.5				
363	STORAGE BATTERY EQUIPMENT																	
363.5	STATION EQUIPMENT - ELECTRONICS																	
364	POLES, TOWERS AND FIXTURES		48 - S0	50 - R2.5	36 - R0.5	39 - R0.5	37 - R1	44 - R1	57 - R1		48 - R4	50 - R1	39 - R1	38 - R2.5	48 - R1	48 - R1	50 - R1	
	POLES, TOWERS AND FIXTURES - WOOD POLES																	
	POLES, TOWERS AND FIXTURES - STEEL TOWERS																	
	CUSTOMER TRANSFORMER STATION												43 - S0.5					
	POLES																	
	CLEARING TOWERS																	
	CLEARING POLES																	
	STEEL																	
365	OVERHEAD CONDUCTORS AND DEVICES		48 - R2	45 - R1.5	40 - O1	47 - R2	41 - R2	46 - O1	53 - R0.5		50 - R2	55 - R1	52 - R1.5	38 - R2.5	53 - R1.5	53 - R1.5	50 - R0.5	
	ROW CLEARING								65 - SQ									
366	UNDERGROUND CONDUIT		55 - S4	70 - R4	65 - R2.5	60 - R3		50 - R3	65 - R3		60 - S3	50 - R3	65 - S3	65 - S3	55 - R3	55 - R3	55 - S0.5	
	ENCASED																	
	NOT ENCASED																	
	UNDERGROUND CONDUIT - MANHOLES																	
367	UNDERGROUND CONDUCTORS AND DEVICES		44 - S0.5	50 - R2	38 - S0.5	47 - R2	40 - R3	45 - R2.5	35 - R3		50 - R2.5	40 - R4	50 - R2.5	43 - R3	44 - R1	44 - R1	55 - R2.5	
	CABLE INJECT																	
	DUCT SYSTEM																	
	DIRECT BURIED																	
368	LINE TRANSFORMERS		40 - R2	45 - R1.5	44 - S1.5	38 - R2	35 - R2.5	37 - L0.5	37 - S0.5		43 - R2.5	38 - R2	38 - R1.5	30 - R1	36 - S0.5	36 - S0.5	36 - R0.5	
	TRANSFORMER INSTALLATIONS						35 - R2.5											
	OVERHEAD																	
	UNDERGROUND																	
	PAD MOUNT																	
	NON-NETWORK HOUSING																	
	NETWORK																	
	UNDERGROUND RESIDENTIAL DISTRIBUTION																	
	CUSTOMER																	
369	SERVICES		43 - R1.5			41 - R2					60 - R4	45 - R4		42 - S3			55 - R4	
	OVERHEAD			45 - S1.5	36 - O1		40 - R3	38 - R1	40 - R0.5				45 - R1		53 - R2	53 - R2.5		
	UNDERGROUND			45 - R1.5	50 - R3		40 - R3	45 - R2.5	38 - R2				55 - S2		60 - R3	60 - R3		
	UNDERGROUND CABLE																	
370	METERS		40 - R1.5	30 - R2	29 - S0.5	35 - R1	33 - S2	37 - R2.5	24 - O1		20 - L2	35 - R1	32 - O1	25 - S2	24 - L1	24 - L1	30 - R0.5	
	METER INSTALLATIONS						33 - S2											
	METERING DEVICES												38 - R2					
	AMR AND ELECTRONIC																15 - S2.5	
	LOAD RESEARCH METERS																	
	AMI METERS											20 - R5						
	IDAHO STANDARD																	
	IDAHO AMR																	
	WASHINGTON STANDARD																	
371	INSTALLATIONS ON CUSTOMERS' PREMISES		20 - R0.5		22 - R2.5	22 - O1			25 - SQ		33 - S0.5		17 - O1				30 - S2	
	AREA LIGHTING								20 - O1									
	PHOTOVOLTAIC INSTALLATIONS																	
	LOAD CONTROL DEVICES																	
372	LEASED PROPERTY											30 - R1						
373	STREET LIGHTING AND SIGNAL SYSTEMS		33 - R1		25 - L0.5	28 - R1	20 - R2	34 - R2	31 - R0.5		35 - R1.5	35 - R2	32 - S0	28 - R2	20 - L0	20 - L0	40 - R1.5	
	MERCURY VAPOR																	
	HIGH PRESSURE SODIUM																	
	OVERHEAD			30 - L1														
	UNDERGROUND			35 - R1.5			20 - R2											
	TRANSFORMERS			26 - R0.5														
	BOULEVARD																	
	CUSTOMER POLES																	
	DUCK TO DAWN																	
	NONROADWAY LIGHTING																	
	CONDUIT AND CABLE																	
	LAMPS AND EQUIPMENT																	
	ELECTROLIERS																	
375	EASEMENTS																	

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client: Company 49 Survivor Curve	Company 50 Survivor Curve	Company 51 Survivor Curve	Company 52 Survivor Curve	Company 53 Survivor Curve	Company 54 Survivor Curve	Company 55 Survivor Curve	Company 56 Survivor Curve	Company 57 Survivor Curve	Company 58 Survivor Curve	Company 59 Survivor Curve	Company 60 Survivor Curve	Company 61 Survivor Curve	Company 62 Survivor Curve	Company 63 Survivor Curve	Company 64 Survivor Curve
	GENERAL PLANT																
389	LAND & LAND RIGHTS - RIGHTS						50 - R5	50 - SQ		70 - R4	65 - R4		50 - SQ			45 - R4	
390	STRUCTURES AND IMPROVEMENTS	60 - S0			45 - R3	40 - R1	50 - R3			45 - R0.5	45 - R2	47 - R1.5	40 - R3			35 - R2	
	LEASEHOLD IMPROVEMENTS	30 - R1				20 - SQ								20 - SQ	20 - SQ		
	LARGE							80 - S0*						100 - S1.5*	100 - S1.5*		
	SMALL							40 - R1						40 - R2.5	40 - R2.5		
	AIR CONDITIONING																
	PAD																
	LEASE																
	MISCELLANEOUS																
391	OFFICE FURNITURE & EQUIPMENT	20 - SQ					15 - SQ		15 - SQ	10 - SQ	20 - SQ	20 - SQ	20 - SQ			15 - SQ	15 - SQ
	FURNITURE				20 - SQ			20 - SQ						15 - SQ	15 - SQ		15 - SQ
	EQUIPMENT	5 - SQ			7 - SQ	15 - SQ											
	COMPUTERS AND SOFTWARE	4 - SQ				5 - SQ		3 - SQ	4 - SQ	5 - SQ	5 - SQ	7 - SQ		5 - SQ	5 - SQ	5 - SQ	5 - SQ
	COMPUTER HARDWARE												5 - SQ				
	SOFTWARE								5 - SQ				10 - SQ				3 - SQ
	LARGE APPLICATION SOFTWARE					10 - SQ			7 - SQ								
	DATA HANDLING						10 - SQ										
	INFORMATION SYSTEMS						5 - SQ										
	AML&P - EKLUTNA																
	POWER MANAGEMENT SYSTEMS																
	CASH PROCESSING EQUIPMENT	5 - SQ															
	EDP																
	SYSTEM DEVELOPMENT																
392	TRANSPORTATION EQUIPMENT					11 - S3					9 - S1		13 - R0.5	12 - R4	12 - R4		
	PASSENGER CARS & VANS						8 - L3			9 - L4						9.5 - R3	7.5 - R0.5
	TRUCKS, TRAILERS AND VANS																
	LIGHT TRUCKS									12 - L3						11 - L2.5	11 - R3
	MEDIUM TRUCKS															10 - S2.5	10 - R2
	HEAVY TRUCKS						15 - R2.5	10 - L3		14 - L4						13 - L3	10 - R4
	MEDIUM TRUCKS / POWER EQUIPPED																
	HEAVY TRUCKS / POWER EQUIPPED																
	AIRPLANES AND HELICOPTERS																
	AIRPLANES									9 - S1.5							
	HELICOPTERS																
	TRACTORS																
	TRAILERS		30 - S4					25 - S1		23 - S0.5						25 - S0.5	16 - R2.5
	MOTOR HOME																18 - R4
	OTHER																10 - S1.5
	SUBUNIT																
393	STORES EQUIPMENT	25 - SQ			20 - SQ		25 - SQ	20 - SQ		10 - SQ	20 - SQ	30 - SQ	15 - SQ	15 - SQ	15 - SQ	25 - SQ	25 - SQ
394	TOOLS, SHOP AND GARAGE EQUIPMENT	25 - SQ	25 - SQ	20 - SQ	20 - SQ	20 - SQ	25 - SQ			15 - SQ	25 - SQ	25 - SQ	20 - SQ	15 - SQ	15 - SQ	25 - SQ	
	ELECTRIC VEHICLES																
395	LABORATORY EQUIPMENT	15 - SQ	15 - SQ	15 - SQ	15 - SQ		15 - SQ			10 - SQ	15 - SQ	20 - SQ	15 - SQ	15 - SQ	15 - SQ	20 - SQ	20 - SQ
396	POWER OPERATED EQUIPMENT	17 - R5	30 - R1.5				18 - SQ	15 - L3		14 - L0.5	14 - L2.5			19 - R1.5	19 - R1.5	16 - L1	20 - R2
	TRENCHERS AND CABLE PLOWS																
	RUBBER TIRED TRACTORS																
	HEAVY CONSTRUCTION EQUIPMENT																
	MOBILE CRANES																
	FORKLIFTS																
	TRAILERS WITH MOUNTED EQUIPMENT																
	MISCELLANEOUS NON-HIGHWAY EQUPMENT																
	MISCELLANEOUS EQUPMENT																
	OTHER POWER OPERATED EQUIPMENT																
	OFF ROAD POWER EQUIPMENT - SHORT LIFE																
	OFF ROAD POWER EQUIPMENT - LONG LIFE																
397	COMMUNICATION EQUIPMENT	15 - SQ		10 - SQ	24 - R4	20 - S4	15 - SQ	15 - R1		15 - SQ	15 - SQ	15 - SQ	20 - R3	15 - SQ	15 - SQ	10 - SQ	10 - SQ
	COMPUTERS																
	STRUCTURES & IMPROVEMENTS																
	COMMUNICATION & CONTROL EQUIPMENT																
	FIBER OPTIC CABLE																
	SCADA					14 - S2							15 - S1				
	TELEPHONE AND DATA COLLECTION EQUIPMENT									10 - SQ							
	TRANS LINE																
	EMS							SQUARE*									
	MICROWAVE																
	ELECTRONIC																
	TOWER/BUILDING																
	CLEARING																
	MASSED																
	OTHER																
	REMOTE MONITORING EQUIPMENT												12 - R2.5				
398	MISCELLANEOUS EQUIPMENT	10 - SQ			20 - SQ		15 - SQ	20 - SQ		10 - SQ	15 - SQ	20 - SQ	20 - SQ	15 - SQ	15 - SQ	20 - SQ	20 - SQ
399	OTHER TANGIBLE PROPERTY																
	MINING EQUIPMENT												40 - R2*				

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 65 Survivor Curve	Company 66 Survivor Curve	Company 67 Survivor Curve	Company 68 Survivor Curve	Company 69 Survivor Curve	Company 70 Survivor Curve	Company 71 Survivor Curve	Company 72 Survivor Curve	Company 73 Survivor Curve	Company 74 Survivor Curve	Company 75 Survivor Curve	Company 76 Survivor Curve	Company 77 Survivor Curve	Company 78 Survivor Curve	Company 79 Survivor Curve	Company 80 Survivor Curve
	INTANGIBLE PLANT																	
302	FRANCHISES AND CONSENTS				40 - SQ													30 - SQ
303	MISCELLANEOUS INTANGIBLE PLANT				Fully Accrued													
	SOFTWARE					7 - SQ		5 - SQ				8 - SQ						
	FIBER OPTIC							15 - SQ										
	5 YR																	
	10 YR																	
	15 YR																	
	25 YR																	
	RRSU UPGRADES																	
	STEAM PRODUCTION PLANT																	
310	LAND AND LAND RIGHTS - RIGHTS											SQUARE*					SQUARE*	50 - SQ
	REMOVING OTHER PROPERTY																	
	EASEMENTS, PERMITS																	
311	STRUCTURES AND IMPROVEMENTS		100 - R2*		30 - R5*				100 - R2.5*	125 - R2*		125 - R2*	80 - R1.5*		75 - R3*	75 - R3*	70 - R1.5*	90 - S0*
	LANDFILL																	
	SECURITY																	
312	BOILER PLANT EQUIPMENT		62 - S0.5*		30 - R5*				50 - S0.5*	65 - R1.5*		60 - R2*	40 - S0*		50 - R1*	50 - R1*	65 - R1*	60 - R1*
	COMBUSTION INITIATIVE																10 - SQ	
	UNIT COAL TRAIN								30 - R3*						25 - R3*	25 - R3*	25 - R3	25 - R3
	POWER OPERATED																20 - L2.5	
	UNCLASSIFIED																40 - S2*	18 - S2*
	SCRUBBERS																	
	FUEL EQUIPMENT		35 - R1.5															10 - SQ
	COAL PILE BASE																	
	POLLUTION CONTROL EQUIPMENT														40 - R2.5*	40 - R2.5*		
	RETROFIT PRECIPITATORS																	
	CATALYST																	
	AQC																	
	CONTINUOUS EMISSION MONITORING																	
	TOOLS																25 - SQ	
	RAIL IMPROVEMENTS																30 - S1.5	
313	ENGINES & GENERATORS																	
314	TURBOGENERATOR UNITS		65 - R2*		30 - R5*				65 - S1*	70 - R2*		70 - R2*	50 - R2*		40 - S1*	40 - S1*	70 - R2*	65 - R2.5*
315	ACCESSORY ELECTRIC EQUIPMENT		50 - R3*		30 - R5*				55 - R2*	70 - S2*		60 - S1.5*	55 - R3*		50 - S1.5*	50 - S1.5*	55 - R1*	65 - R2.5*
	COMBUSTION INITIATIVE																10 - SQ	
316	MISCELLANEOUS PLANT EQUIPMENT		48 - S0.5*		30 - R5*				40 - S0*	45 - R0.5*		50 - R1.5*	42 - R0.5*		40 - R1.5*	40 - R1.5*	43 - S0.5*	45 - R1*
	COMBUSTION INITIATIVE																10 - SQ	
	AIR MONITORING EQUIPMENT																10 - S0.5	
	FURNITURE																20 - SQ	
	DATA PROCESSING EQUIPMENT																7 - SQ	
	CARS																10 - L3	
	TOOLS, SHOP AND GARAGE EQUIPMENT																	
	POWER OPERATED EQUIPMENT																20 - L2.5	
	COMMUNICATION EQUIPMENT																15 - SQ	
	SMALL TRUCKS																	
	LARGE TRUCKS																	
	TRAILERS																	
	MISCELLANEOUS																25 - SQ	
	NUCLEAR PRODUCTION																	
320	LAND AND LAND RIGHTS - RIGHTS																	
321	STRUCTURES AND IMPROVEMENTS				100 - R1*								80 - S0.5*					
322	REACTOR PLANT EQUIPMENT				60 - R1*								50 - S1.5*					
	STEAM GENERATORS																	
323	TURBOGENERATOR UNITS				40 - R3*								50 - S1*					
324	ACCESSORY ELECTRIC EQUIPMENT				40 - R3*								45 - S2.5*					
325	MISCELLANEOUS PLANT EQUIPMENT				40 - R4*								35 - L1.5*					
	HYDRAULIC PRODUCTION PLANT																	
330	LAND AND LAND RIGHTS - RIGHTS											120 - S4						
	REMOVING PROPERTY OF OTHERS																	
331	STRUCTURES AND IMPROVEMENTS				100 - S2.5*				SQUARE*	100 - S1.5*		100 - S1*	100 - R2*				80 - S1*	65 - S0*
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
332	RESERVOIRS, DAMS AND WATERWAYS				100 - S2.5*				SQUARE*	100 - S1.5*		70 - R1*	125 - R2.5*				100 - S1.5*	70 - R2.5*
	FISH & WILDLIFE CONSERVATION																	
	RECREATION																	
333	WATER WHEELS, TURBINES AND GENERATORS				70 - R1.5*				70 - R2.5*	70 - R1.5*		65 - R1.5*	80 - R2*				70 - R1.5*	45 - R1.5*
334	ACCESSORY ELECTRIC EQUIPMENT				40 - R5*				55 - R3*	65 - R1*		55 - S3*	55 - O1*				40 - R0.5*	55 - R0.5*
335	MISCELLANEOUS PLANT EQUIPMENT				40 - R3*				50 - R2.5*	35 - S1.5*		50 - S2.5*	60 - R1*				50 - R2.5*	55 - R2*
	EQUIPMENT																	

Service Life and Net Salvage Statistics - US - Electric

	Client:	Company 65	Company 66	Company 67	Company 68	Company 69	Company 70	Company 71	Company 72	Company 73	Company 74	Company 75	Company 76	Company 77	Company 78	Company 79	Company 80
FERC Acct.	Description	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	FURNITURE																
	COMPUTER																
	FISH & WILDLIFE CONSERVATION																
	RECREATION																
336	ROADS, RAILROADS AND BRIDGES			60 - R1.5*					70 - R5*		55 - R3*	60 - R4*					60 - R2*
	OTHER PRODUCTION PLANT																
340	LAND AND LAND RIGHTS - RIGHTS															SQUARE*	
341	STRUCTURES AND IMPROVEMENTS	60 - S0*		25 - R5				SQUARE*	40 - R5*		SQUARE*	40 - S0.5*		SQUARE*	SQUARE*	65 - R3*	45 - S3*
	COMBINED CYCLE PRODUCTION			30 - R5*													
342	FUEL HOLDERS	SQUARE*		25 - R5				SQUARE*	40 - R5*		SQUARE*	30 - S2*				50 - S3*	55 - R3*
	COMBINED CYCLE PRODUCTION			30 - R5*													
343	PRIME MOVERS	60 - R2.5*		25 - R5				55 - R2.5*			SQUARE*	25 - S2.5*				60 - R3*	
	SOLAR																
	WIND TURBINE																
	FUEL CELLS	SQUARE*															
	BASE LOAD																
	PEAKERS																
	CONTINUOUS EMISSION MONITORING																
	COMBINED CYCLE PRODUCTION			30 - R5*													
344	GENERATORS	65 - R2.5*		25 - R5				44 - R4*	40 - R5*		SQUARE*	60 - S2*		40 - S2.5*	40 - S2.5*	25 - S0.5*	40 - R3*
	PORTABLE POWER MODULES																
	SOLAR																
	WIND															35 - R2.5*	
345	ACCESSORY ELECTRIC EQUIPMENT	55 - S1.5*		25 - R5				45 - S1.5*	40 - R5*		SQUARE*	40 - S1.5*		40 - S3*	40 - S3*	45 - R4*	40 - S0.5*
	COMBINED CYCLE PRODUCTION			30 - R5*													
	WIND																
346	MISCELLANEOUS PLANT EQUIPMENT	SQUARE*		25 - R5				40 - R1.5*	40 - R5*		SQUARE*	35 - R2.5*		SQUARE*	SQUARE*	60 - R3*	40 - R2.5*
	COMBINED CYCLE PRODUCTION			30 - R5*													
	SOLAR PRODUCTION			SQUARE*													
	WIND																
	A/V															20 - SQ	
348	EASEMENTS								SQUARE*								
	TRANSMISSION PLANT																
350	LAND AND LAND RIGHTS - RIGHTS				80 - SQ		70 - S4	75 - R4		75 - R4	70 - R4						
351	EASEMENTS								50 - SQ								
352	STRUCTURES AND IMPROVEMENTS	60 - R2.5		60 - R3	55 - R3		55 - R4	75 - R3	55 - R3	50 - R4	55 - R4	65 - R2.5*	55 - R3				
	MAJOR																
	SMALL																
	NON SYS CONTROL/COM																
	SYS CONTROL/COM																
353	STATION EQUIPMENT	43 - R1.5		43 - R2.5	48 - R2		47 - R1	60 - R2	45 - R1	40 - R2	65 - R3	60 - S0.5*	57 - R3				
	STEP-UP TRANSFORMERS			25 - S0								60 - R3*					
	STEP-UP EQUIPMENT																
	MISCELLANEOUS / OTHER																
	MICROWAVE																
	SCADA												13 - S2				
	SUPERVISORY EQUIPMENT																
	SUBSTATION ON CUSTOMER PREMISES																
	PORTABLE PROPERTY AT SUBSTATIONS																
	METERING STATION																
	NON SYS CONTROL/COM																
	SYS CONTROL/COM																
	RTU																
	ELECTRONICS																
	MAJOR																
	COMMUNICATION EQUIPMENT																
	SECURITY																
	LEASEHOLD											20 - SQ					
354	TOWERS AND FIXTURES	70 - R2		70 - R5	65 - R3		65 - R3	70 - R2.5	65 - R4	56 - R3	65 - R3	65 - R4	70 - R4				
	ROW CLEARING						70 - R4										
355	POLES AND FIXTURES	45 - R2		47 - R2.5	57 - R3		55 - R1.5	56 - S0	45 - R2	31 - R0.5	70 - R3	53 - R2.5	49 - R2.5				
	ROW CLEARING						70 - R4										
	POLES AND FIXTURES - WOOD																
	POLES AND FIXTURES - STEEL																
	MINT LINE	50 - SQ															
	LEASEHOLD											20 - SQ					
356	OVERHEAD CONDUCTORS AND DEVICES	48 - R1.5		53 - R5	60 - R3		55 - R3	65 - R2	50 - R3	38 - R2.5	65 - R4	60 - S2	53 - R2				
	ROW CLEARING				80 - SQ												
	ON TOWERS																
	MINT LINE	50 - SQ															
357	UNDERGROUND CONDUIT	65 - R3		60 - R5	50 - R3		50 - R4	65 - R3		55 - R4	60 - S4	55 - R4	50 - L3				
358	UNDERGROUND CONDUCTORS AND DEVICES	30 - R3		50 - R3			40 - R3	30 - SQ	50 - R3	55 - R4	50 - S3	50 - R3	40 - R4				
	SUB. CABLE - SOUTH																
	SUB. CABLE - NORTH																
359	ROADS AND TRAILS			65 - R5	50 - SQ		70 - R4		60 - R4	75 - SQ	70 - R4	55 - S3					

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client: Company 65 Survivor Curve	Company 66 Survivor Curve	Company 67 Survivor Curve	Company 68 Survivor Curve	Company 69 Survivor Curve	Company 70 Survivor Curve	Company 71 Survivor Curve	Company 72 Survivor Curve	Company 73 Survivor Curve	Company 74 Survivor Curve	Company 75 Survivor Curve	Company 76 Survivor Curve	Company 77 Survivor Curve	Company 78 Survivor Curve	Company 79 Survivor Curve	Company 80 Survivor Curve
	DISTRIBUTION PLANT																
360	LAND & LAND RIGHTS - RIGHTS				65 - SQ		65 - R3	70 - R3		74 - R4	65 - R4						70 - R3
	EASEMENTS, SURVEYS AND CLEARING																
361	STRUCTURES AND IMPROVEMENTS			55 - L5	45 - R3	55 - R3	65 - R2.5	60 - R1.5	55 - R3	50 - S3	55 - R3	65 - R2.5	50 - R3			56 - R2.5	45 - R3
	STRUCTURES AND IMPROVEMENTS - MAJOR	50 - R2															
	STRUCTURES AND IMPROVEMENTS - SMALL	45 - R1.5															
	LEASEHOLD											20 - SQ					
362	STATION EQUIPMENT	50 - R0.5		40 - R2.5	50 - R1	46 - R2.5	50 - R2	50 - R0.5	45 - R1.5	40 - R2	55 - R4	60 - S0.5	40 - S1			46 - S0	48 - R2
	MAJOR																
	ELECTRONIC																
	SCADA																
	COMPANY STATIONS																
	CUSTOMER HIGH TENSION																
	CONTROL CENTER																
	SUPERVISORY																
	TRANSFORMERS																
	OTHER																
	SECURITY																
	COMMUNICATION EQUIPMENT															15 - SQ	
	LEASEHOLD											20 - SQ					
	REMOTE MONITORING EQUIPMENT																
363	STORAGE BATTERY EQUIPMENT			10 - SQ													
363.5	STATION EQUIPMENT - ELECTRONICS																
364	POLES, TOWERS AND FIXTURES	32 - R1.5	42 - R0.5	40 - R2		43 - R0.5		43 - R0.5	45 - R2	23 - R2	65 - R1	44 - R1.5	54 - R2.5			52 - R2	50 - R1.5
	POLES, TOWERS AND FIXTURES - WOOD POLES																
	POLES, TOWERS AND FIXTURES - STEEL TOWERS						55 - R3										
	CUSTOMER TRANSFORMER STATION																
	POLES						44 - O1										
	CLEARING TOWERS						55 - S3										
	CLEARING POLES						65 - R3										
	STEEL																
365	OVERHEAD CONDUCTORS AND DEVICES	34 - R1.5	35 - L2	40 - R2.5	58 - R0.5	40 - S2.5	45 - R1	50 - R0.5	40 - R2.5	24 - R2	55 - R3	55 - R2	51 - R1			50 - R2	38 - O1
	ROW CLEARING				65 - SQ												
366	UNDERGROUND CONDUIT			54 - R4	65 - R3	60 - R4	55 - R3	65 - R3	50 - R4	51 - S1.5	65 - R4	43 - R3	65 - R3			50 - R2	55 - R2
	ENCASED																
	NOT ENCASED																
	UNDERGROUND CONDUIT - MANHOLES	60 - R3															
367	UNDERGROUND CONDUCTORS AND DEVICES	32 - R2	30 - R2.5	39 - R4	35 - R3	55 - R2	43 - S1.5	55 - R2	35 - R2.5	29 - R0.5	65 - R4	45 - S0.5	40 - R3			40 - R1.5	45 - R2
	CABLE INJECT																
	DUCT SYSTEM																
	DIRECT BURIED																
368	LINE TRANSFORMERS	33 - R2.5	39 - R1.5		32 - S0	32 - S0		35 - R1	40 - R2	26 - R1.5	50 - R0.5	44 - R2	40 - S1			40 - R1	35 - R1.5
	TRANSFORMER INSTALLATIONS												35 - L2				
	OVERHEAD			32 - R2.5			34 - SQ										
	UNDERGROUND			29 - S2.5													
	PAD MOUNT						48 - SQ										
	NON-NETWORK HOUSING						35 - SQ										
	NETWORK																
	UNDERGROUND RESIDENTIAL DISTRIBUTION																
	CUSTOMER																
369	SERVICES	45 - R3	40 - R1				42 - R1.5		45 - R3	22 - S2.5	60 - R2		44 - R2			51 - R1.5	
	OVERHEAD			47 - R3	39 - O1	48 - R0.5		35 - R1				60 - R3					50 - R1.5
	UNDERGROUND			44 - R4	36 - R3	45 - S4		40 - R1.5				65 - R3				51 - R1.5	55 - R2.5
	UNDERGROUND CABLE					50 - S1											
370	METERS	28 - R4	32 - R3	30 - R1.5	26 - S0	39 - R2	28 - SQ	32 - R2	35 - R2.5	25 - S1	30 - R0.5	44 - R1	32 - R2			15 - L0	25 - R0.5
	METER INSTALLATIONS												65 - R5			17 - R0.5	
	METERING DEVICES															38 - R1	
	AMR AND ELECTRONIC						15 - SQ					15 - S2.5	15 - S3				14 - R3
	LOAD RESEARCH METERS																
	AMI METERS															15 - S2.5	
	IDAHO STANDARD																
	IDAHO AMR																
	WASHINGTON STANDARD																
371	INSTALLATIONS ON CUSTOMERS' PREMISES	16 - R1	30 - R1	40 - S1	25 - SQ	30 - R4	35 - R3	14 - L0			35 - R2		30 - O1			25 - R3	26 - R1.5
	AREA LIGHTING				20 - O1		19 - L0.5						19 - R1.5				
	PHOTOVOLTAIC INSTALLATIONS																
	LOAD CONTROL DEVICES																
372	LEASED PROPERTY			16 - S1	30 - SQ												
373	STREET LIGHTING AND SIGNAL SYSTEMS	29 - R1.5	30 - R1		22 - O1		30 - L1.5	24 - R1	35 - R2	27 - S0	50 - R2	33 - S1	35 - L1			40 - R2.5	44 - R1
	MERCURY VAPOR																
	HIGH PRESSURE SODIUM																
	OVERHEAD			30 - R0.5		7 - L0											
	UNDERGROUND					30 - R2.5											
	TRANSFORMERS																
	BOULEVARD																
	CUSTOMER POLES																
	DUCK TO DAWN					32 - O1											
	NONROADWAY LIGHTING																
	CONDUIT AND CABLE			25 - S6													
	LAMPS AND EQUIPMENT			22 - L0													
	ELECTROLIERS			24 - L3													
375	EASEMENTS								50 - SQ								

Service Life and Net Salvage Statistics - US - Electric

FERC Acct.	Description	Client:	Company 65	Company 66	Company 67	Company 68	Company 69	Company 70	Company 71	Company 72	Company 73	Company 74	Company 75	Company 76	Company 77	Company 78	Company 79	Company 80
			Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve	Survivor Curve
	GENERAL PLANT																	
389	LAND & LAND RIGHTS - RIGHTS					50 - SQ		65 - R4			55 - R4	65 - R4						
390	STRUCTURES AND IMPROVEMENTS				40 - R3		50 - R3			35 - R4	40 - R2.5	57 - R4	37 - S0.5	125 - R1*			40 - R0.5	50 - R1.5*
	LEASEHOLD IMPROVEMENTS							JLLY ACCRUE						SQUARE*				
	LARGE		SQUARE*			80 - S0*	60 - R2*	55 - S0*	60 - R1*				25 - S2					
	SMALL		33 - S1			40 - R1		45 - R3	40 - R3									
	AIR CONDITIONING							30 - R2										
	PAD																	
	LEASE												20 - SQ					
	MISCELLANEOUS																	
391	OFFICE FURNITURE & EQUIPMENT				20 - SQ				20 - SQ		10 - SQ	20 - SQ	20 - SQ	20 - SQ			20 - SQ	
	FURNITURE					20 - SQ	15 - SQ	20 - SQ										
	EQUIPMENT					10 - SQ		15 - SQ		20 - SQ							5 - SQ	
	COMPUTERS AND SOFTWARE		6 - R4			3 - SQ		5 - SQ	5 - SQ	5 - SQ	6 - SQ	5 - SQ		5 - SQ			5 - SQ	5 - SQ
	COMPUTER HARDWARE																	
	SOFTWARE																	
	LARGE APPLICATION SOFTWARE																	
	DATA HANDLING						8 - SQ						20 - SQ					
	INFORMATION SYSTEMS						10 - SQ											
	AML&P - EKLUTNA																	
	POWER MANAGEMENT SYSTEMS							7 - SQ										
	CASH PROCESSING EQUIPMENT																	
	EDP												5 - SQ					
	SYSTEM DEVELOPMENT																	
392	TRANSPORTATION EQUIPMENT		13 - R2					SQUARE		10 - SQ		14 - L1					12 - R1.5	
	PASSENGER CARS & VANS										5 - S2			7 - L4				
	TRUCKS, TRAILERS AND VANS																	
	LIGHT TRUCKS					7 - L3					10 - S1			12 - L2.5				
	MEDIUM TRUCKS																	
	HEAVY TRUCKS					10 - S3								14 - S3				
	MEDIUM TRUCKS / POWER EQUIPPED																	
	HEAVY TRUCKS / POWER EQUIPPED																	
	AIRPLANES AND HELICOPTERS																	
	AIRPLANES																	
	HELICOPTERS																	
	TRACTORS																	
	TRAILERS					26 - S1		19 - L0.5	26 - L1.5									
	MOTOR HOME																	
	OTHER																	
	SUBUNIT																	
393	STORES EQUIPMENT					20 - SQ	25 - SQ	25 - SQ	20 - SQ	20 - SQ	15 - SQ	20 - SQ	25 - SQ	10 - SQ			20 - SQ	
394	TOOLS, SHOP AND GARAGE EQUIPMENT				25 - SQ	25 - SQ	25 - SQ	20 - SQ	25 - SQ	20 - SQ	20 - SQ	25 - SQ	20 - SQ	20 - SQ			25 - SQ	
	ELECTRIC VEHICLES																	
395	LABORATORY EQUIPMENT				20 - SQ	20 - SQ	15 - SQ	20 - SQ	20 - SQ	20 - SQ	20 - SQ	15 - SQ	20 - SQ	10 - SQ			15 - SQ	
396	POWER OPERATED EQUIPMENT		18 - L0.5		20 - SQ	21 - S0.5	22 - S2.5	15 - SQ	20 - S0.5	15 - SQ	14 - S1.5	14 - R1.5		18 - S0.5			14 - L1.5	
	TRENCHERS AND CABLE PLOWS																	
	RUBBER TIRED TRACTORS																	
	HEAVY CONSTRUCTION EQUIPMENT																	
	MOBILE CRANES																	
	FORKLIFTS																	
	TRAILERS WITH MOUNTED EQUIPMENT																	
	MISCELLANEOUS NON-HIGHWAY EQUPMENT																	
	MISCELLANEOUS EQUPMENT																	
	OTHER POWER OPERATED EQUIPMENT																	
	OFF ROAD POWER EQUIPMENT - SHORT LIFE																	
	OFF ROAD POWER EQUIPMENT - LONG LIFE																	
397	COMMUNICATION EQUIPMENT		20 - R1.5		15 - SQ	15 - R1	15 - SQ	15 - SQ	19 - L2	15 - SQ	15 - SQ	15 - SQ	8 - SQ	10 - SQ			15 - SQ	10 - SQ
	COMPUTERS																	
	STRUCTURES & IMPROVEMENTS																	
	COMMUNICATION & CONTROL EQUIPMENT																	
	FIBER OPTIC CABLE																	
	SCADA																	
	TELEPHONE AND DATA COLLECTION EQUIPMENT																	
	TRANS LINE																	
	EMS					SQUARE*												
	MICROWAVE																	
	ELECTRONIC																	
	TOWER/BUILDING																	
	CLEARING																	
	MASSED																	
	OTHER																	
	REMOTE MONITORING EQUIPMENT																	
398	MISCELLANEOUS EQUIPMENT				20 - SQ	20 - SQ	20 - SQ	20 - SQ	15 - SQ	15 - SQ	10 - SQ	20 - SQ	20 - SQ	10 - SQ				
399	OTHER TANGIBLE PROPERTY													5 - SQ				
	MINING EQUIPMENT																	

* Curve shown is interim survivor curve.

APPROVED INTERIM SURVIVOR CURVES AND
NET SALVAGE PERCENTS FOR ELECTRIC COMPANIES

COMPANIES INCLUDED IN THIS LIST ARE THE FOLLOWING:

Dominion - Virginia Power
Nova Scotia Power, Inc.
Michigan Electric Transmission Company
Duke Power Company
Potomac Electric Power Company
NSTAR - Electric
Owen Elecrtric Cooperative
Omaha Public Power District
Puget Sound Energy
Reliant Energy
Dominion Resources, Inc.
UGI Utilities, Inc. - Electric Division
Greater Missouri Operations - L&P Jurisdiction
Chugach Electric Association, Inc
PSI Energy, Inc.
Madison Gas and Electric Company
Bangor Hydro - Electric Company
Entergy Arkansas, Inc.
Kentucky Utilities
Bonneville Power Administration

MidAmerican Energy Company
Alliant Energy - Wisconsin Power & Light
Northern Indiana Public Service Company
AmerenUE
Cincinnati Gas and Electric Company
Duke Energy Indiana
Anchorage Municipal Power & Light
Boston Edison Company
Entergy Texas, Inc.
Central Vermont Public Service Corporation
Exelon Generation Company
Pacific Gas & Electric Company
Maine Public Service Company
Allegheny Energy Supply, Inc.
Jackson Energy Cooperative Corporation
Maritime Electric Company
Duquesne Light Company
Westar Energy, Inc. - North
Alliant - Iowa
AmerenIP

Idaho Power Company
AmerenCILCO
South Carolina Electric & Gas Company
PPL Electric Utilities Corporation
Alliant - Minnesota
Sierra Pacific Power Company
Atlantic City Electric Company
Arizona Public Service Company
Greater Missouri Operations - MPS Jurisdiction
Allegheny Energy - Monongahela Power Company
Entergy Gulf States Louisiana, LLC.
Oklahoma Gas and Electric
Duke Energy Ohio
Wisconsin Power and Light Company
Wisconsin Public Service Corporation
AmerenCIPS
Pennsylvania Electric Company
Duke Energy Kentucky
Entergy Mississippi, Inc.
Nevada Power Company

Oklahoma Gas and Electric (Holding Company Assets)
East Kentucky Power Cooperative
Allegheny Energy - Potomac Edison Company
Centerpoint Energy - Houston Electric LLC
NSTAR Electric & Gas Company - Commonwealth Electric Company
Duke Energy Carolinas
Central Hudson Gas and Electric
Kansas City Power and Light Company - Kansas Jurisdiction
Westar Energy, Inc. - South
Louisville Gas & Electric
Metropolitan Edison Company
Black Hills Colorado Electric Utility Company, LP
Avista Corporation
Maui Electric Company
Florida Power & Light Company
Kansas City Power and Light Company - Missouri Jurisdiction
El Paso Electric Company
Alliant - Illinois
Entergy Louisiana, LLC.
Greater Missouri Operations - ECORP

Service Life and Net Salvage Statistics - Canada - Electric

Client:	Company 1	Company 2	Company 3	Company 4	Company 5	Company 6	Company 7	Company 8	Company 9	Company 10	Company 11	Company 12	Company 13	Company 14
Description	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**
WIND TURBINES														
EQUIPMENT											40 - R3			
WIND TURBINES											5 - SQ	40 - R3		
RESIDUAL HEATING SYSTEMS											25 - R2	25 - R2		
HYDRO PRODUCTION														
LAND AND LAND RIGHTS						75 - R4								
STRUCTURES AND IMPROVEMENTS						65 - L3					100 - R3			
RESERVOIRS, DAMS, AND WATERWAYS						75 - R4					100 - R3			
WATER WHEELS, TURBINES, AND GENERATORS						75 - R3					65 - L1.5			
ACESSORY ELECTRICAL EQUIPMENT						45 - R2.5					31 - L2.5			
ROADS, RAILROADS AND BRIDGES						75 - S4					75 - R4			
CANALS, PENSTOCKS, SURGE TANKS AND TAILRACES														
OTHER POWER PLANT EQUIPMENT						45 - R3					15 - L1			30 - R3
OTHER PRODUCTION														
STRUCTURES AND IMPROVEMENTS										50 - S1.5	30 - S2.5	35 - R2.5		40 - R2.5
ELECTRICAL PLANT														
PRIME MOVERS, GENERATORS AND AUXILIARIES										25 - R1.5		25 - R1.5		27 - R2.5
PRIME MOVERS											20 - R3			
GENERATORS											28 - R4	27 - R2.5		
FUEL HOLDERS										23 - L2	30 - L4	20 - R2		35 - R4
ACCESSORY ELECTRICAL EQUIPMENT										30 - R1.5	21 - L4	25 - R2		35 - R3
OTHER PRODUCTION PLANT						40 - R4				27 - R3	19 - R4	20 - R3		35 - R3
TRANSMISSION PLANT														
LAND AND LAND RIGHTS	75 - R3	52 - S6				75 - R3					65 - SQ			
SUBSTATION STRUCTURES AND IMPROVEMENTS		50 - R2									40 - R3		40 - R4	
BUILDINGS				40 - R2.5			40 - R4							
SITE DEVELOPMENT				40 - R3										
SUBSTATION EQUIPMENT	53 - R3	45 - L2		45 - R3		50 - S3	38 - R2			45 - R4	31 - L1.5		35 - R2	40 - R4
TRANSFORMERS AND REGULATORS													40 - R2	
RELAYING AND PROTECTION EQUIPMENT													20 - R1.5	
MISCELLANEOUS														
TELECONTROL SYSTEM							15 - R1.5						15 - R1.5	
TELECONTROL LINKS				13 - R0.5										
SUPERVISORY EQUIPMENT				10 - L1.5										
FIBER OPTIC CABLE							10 - SQ							
SYSTEM COMMUNICATION		24 - L0.5					10 - SQ							
SCADA							12 - SQ							
ROADS AND TRAILS						40 - R0.5					40 - R2			
LAND RIGHTS				50 - R4										
POLES, TOWERS AND FIXTURES						45 - S2	45 - R3			50 - R4				
WOOD				50 - R1.5										
STEEL				50 - R4										
INSULATORS				37 - R0.5										
TOWERS AND FIXTURES	50 - R4	45 - R2									65 - R4			
POLES AND FIXTURES	55 - R3	52 - R3	30 - S1								45 - R3			
OVERHEAD CONDUCTOR		60 - R4	45 - R2.5	47 - R3		50 - R3				50 - R4	60 - R4			
POLES	60 - R4													
TOWERS	60 - R4													
UNDERGROUND CONDUIT				40 - R4							25 - R3			
MANHOLES				50 - R4										
UNDERGROUND CONDUCTOR		45 - R5									25 - R3			
UNDERGROUND CABLE LPOF				45 - R5										
UNDERGROUND CABLE HPOF				45 - R4										
UNDERGROUND CABLE SOLID DIELECTRIC				35 - S3										
DISTRIBUTION PLANT														
LAND AND LAND RIGHTS	75 - R3			50 - SQ	36 - L3	75 - R3			75 - R3	75 - R3				75 - R3
SUBSTATION STRUCTURES AND IMPROVEMENTS					25 - L1						40 - R1.5	40 - R2		
BUILDINGS				40 - SQ	40 - R1.5									
SITE DEVELOPMENT				35 - SQ										
STORAGE BATTERY EQUIPMENT												15 - R3		
POLES, TOWERS AND FIXTURES	45 - R2.5		30 - R1.5		45 - R1.5	40 - R3			45 - R4	44 - R4	45 - R3	38 - R3		40 - R3
WOOD POLES				50 - R1.5										
OVERHEAD TRANSFORMERS				50 - SQ										
INSULATORS				60 - SQ										
CONCRETE AND STEEL														
STEEL TOWERS														
OVERHEAD CONDUCTOR	55 - R2.5		35 - R1.5		45 - R1	40 - R3			40 - R4	50 - R3	45 - R4	40 - R3		40 - R3
PRIMARY CONDUCTOR				50 - R1.5										
SECONDARY CONDUCTOR				60 - R3										

Service Life and Net Salvage Statistics - Canada - Electric

Client:	Company 1	Company 2	Company 3	Company 4	Company 5	Company 6	Company 7	Company 8	Company 9	Company 10	Company 11	Company 12	Company 13	Company 14
Description	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**
FAULT INDICATORS				65 - R2										
SWITCHES				55 - R2										
BARE COPPER														
WEATHER-PROOF COPPER														
BARE ALUMINUM														
WEATHER-PROOF ALUMINUM														
AERIAL CABLE														
DUPLEX, TRIPLEX, AND QUADRUPLEX														
UNDERGROUND CONDUIT	55 - R4			40 - SQ							25 - R3	25 - R3		50 - R4
TRANSOFRMER PADS				65 - SQ										
PULL BOXES				55 - SQ										
MANHOLES				60 - SQ										
UNDERGROUND CONDUCTOR			35 - R1.5		58 - R2				50 - R3	59 - R3	25 - R3	25 - R3		
PRIMARY CABLE				45 - R3										
SECONDARY CABLE				45 - R3										
SWITCHES				32 - R3										
SPECIAL INSULATED COPPER CABLE														
SUBTATION EQUIPMENT	50 - R3		45 - R2		27 - R0.5	45 - R2.5			31 - S2	50 - R2	30 - R4	35 - S3		35 - R3
LINE TRANSFORMERS	40 - R2.5					45 - L2.5			35 - S3	33 - R3	40 - S3	35 - R2		35 - R3
TRANSFORMERS - OVERHEAD				50 - R3										
TRANSFORMERS - PADMOUNT				50 - R3										
TRANSFORMERS - MINIPAD				55 - SQ										
TRANSFORMERS - SUBSTATIONS				45 - SQ										
SWITCHGEAR				35 - SQ										
STRUCTURES				35 - SQ										
PROTECTION				35 - SQ										
SCADA					10 - R2									
AMR					15 - R1.5									
AMR - SKID INFRASTRUCTURE					25 - R1.5									
VOLTAGE REGULATORS														
CAPACITOR BANKS														
RECLOSERS														
CAPACITORS AND REGULATORS			30 - R1.5											
STREET LIGHTING AND SIGNAL SYSTEMS	43 - R4				20 - R1	35 - R3			35 - S3	35 - S3	45 - R4	35 - S1.5		25 - R3
SENTINEL LIGHTS	31 - R1								30 - R1	30 - S1.5				23 - R2
TELECONTROL LINKS				35 - SQ										
SUPERVISORY EQUIPMENT				15 - SQ										
STREET LIGHT POLES					45 - R1.5									
SERVICES			30 - S3			75 - R4					55 - R4	40 - R3		
OVERHEAD	50 - R4								45 - R3	50 - R3				40 - R3
UNDERGROUND	50 - R3								40 - R3	35 - R3				40 - R4
METERS	20 - R1.5		15 - R1.5	25 - SQ		25 - L1				16 - L0	20 - R3	25 - S2		
AMI														
AMR	15 - R2.5				15 - R0.5				15 - R2.5					25 - S2
WATT-HOUR														
DEMAND														
INSTRUMENT TRANSFORMERS														
METERING TANKS														
INSTALLATIONS ON CUSTOMER PREMISES			15 - R1.5			25 - R1					20 - R3	25 - S2		
GENERAL PLANT														
STRUCTURES AND IMPROVEMENTS	55 - R3	43 - R3		100 - R1					42 - S2	45 - R3		45 - R3	80 - R1	32 - R4
LEASEHOLD IMPROVEMENTS				5 - SQ										
HOUSES	12 - L0													40 - R3
FRAME AND IRON						40 - R3								
MASONRY						30 - R2								
GENERAL								20 - SQ						
SCADA								15 - SQ						
BUILDINGS								50 - R2						
LARGE											100 - R2			
SMALL											15 - L3			
OFFICE FURNITURE AND EQUIPMENT	15 - R3	15 - SQ	15 - SQ	20 - SQ	15 - SQ	15 - SQ		15 - SQ	15 - SQ	15 - SQ 5 - SQ	15 - SQ	5 - SQ		15 - SQ
COMPUTERS														
FURNITURE													15 - SQ	
EQUIPMENT													10 - SQ	
COMPUTER SOFTWARE											5 - SQ			
COMPUTER HARDWARE			5 - SQ								5 - SQ			
TRANSPORTATION EQUIPMENT		9 - L0.5		13 - L3		13 - L2.5				20 - L1	7 - S1	12 - L1.5		10 - R0.5
CATEGORY 1	10 - L1.5								9 - L2					
CATEGORY 2	12 - L1													
CATEGORY 3	25 - R3								20 - R3					
CATEGORY 4	12 - R2													
FLEET VEHICLES					5 - L1									
CORPORATE VEHICLES					3 - SQ									
OTHER					14 - S4			17 - L1.5						
CARS								6 - S3						
LIGHT TRUCKS								8 - S3						
MEDIUM TRUCKS								7 - L3						

Service Life and Net Salvage Statistics - Canada - Electric

Client:	Company 1	Company 2	Company 3	Company 4	Company 5	Company 6	Company 7	Company 8	Company 9	Company 10	Company 11	Company 12	Company 13	Company 14
Description	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**	**SURVIVOR CURVE**
HEAVY TRUCKS								13 - L4						
TRAILERS								15 - L2.5						
HEAVY EQUIPMENT								17 - L1.5						
SNOWMOBILES AND ATV'S								9 - L2.5						
STORES EQUIPMENT			25 - SQ								25 - R3	25 - R3		
TOOLS AND WORK EQUIPMENT	10 - R2	10 - SQ	25 - SQ	20 - SQ	10 - SQ	15 - SQ	15 - SQ	15 - SQ	10 - SQ	10 - SQ	15 - SQ	15 - SQ	8 - SQ	15 - SQ
METER READERS								3 - L2.5						
LABORATORY EQUIPMENT			20 - SQ								25 - SQ	20 - SQ		
HEAVY WORK EQUIPMENT														
POWER OPERATED EQUIPMENT		25 - L2									27 - S1.5	20 - L1		
COMMUNICATION STRUCTURES AND EQUIPMENT	25 - R2		15 - SQ			15 - SQ			15 - R4	20 - L3	20 - R3	25 - R3		15 - SQ
RADIOS				15 - SQ										
MOBILE					7 - SQ									
BASE STATIONS														
RADIO SITES - ROADS														
RADIO SITES - BUILDINGS														
COMMUNICATION CABLES														
SCADA														
TELEPHONE														
POWER LINE CARRIER														
TEST EQUIPMENT														
COMPUTER SYSTEMS	5 - S0.5				3 - SQ	5 - SQ		6 - SQ						5 - SQ
SOFTWARE		5 - SQ		5 - SQ	5 - SQ				10 - SQ				4 - SQ	
HARDWARE		5 - SQ		5 - SQ	5 - R4				5 - SQ				4 - SQ	
ENTERPRISE SOFTWARE				10 - SQ										
INFORMATION SYSTEMS							10 - SQ							
SAP					10 - R4									
MAJOR APPLICATIONS					5 - R4									
LOAD SETLLEMENT SOFTWARE					5 - R4									
MISCELLANEOUS EQUIPMENT			25 - L2								15 - SQ	15 - SQ		
ENVIRONMENT							15 - SQ							
ENGINEERING														
OTHER TANGIBLE PLANT											20 - SQ			

APPROVED INTERIM SURVIVOR CURVES AND
NET SALVAGE PERCENTS FOR ELECTRIC COMPANIES

COMPANIES INCLUDED IN THIS LIST ARE THE FOLLOWING:

NB Power
The City of Red Deer Electric System
Northwest Territories Power Corporation
Atco Electric
FortisAlberta, Inc.
Qulliq Energy Corporation
Cap Rock Energy
The City of Lethbridge Electic Utility
Yukon Electrical Company Limited
AltaLink LP
Northland Utilities (Yellowknife) Power Corporation
FortisBC Inc.
Enmax Power Corporation
Northland Utilities (NWT) Power Corporation

The Yukon Electrical Company Limited
Fully Loaded Labour Rates 2008-2012

	Job Class	Job Title	2008	2009	2010	2011	2012
Salary Rate per Hour:	570000	Entry Level Labourer (Note 1)	$ 17.00	$ 17.51	$ 18.04	$ 18.58	$ 19.13
	573000	Equipment Operator - Entry (Note 2)	$ 17.66	$ 19.33	$ 19.86	$ 20.46	$ 21.18
	558100/558110	Lead Lineman / PLT Team lead (Note 2)	$ 36.53	$ 41.16	$ 42.30	$ 43.57	$ 45.11
Burden Rates (per System):		Fringe Benefits	21%	24%	24%	24%	31%
		Other Earnings	10%	10%	10%	10%	10%
		Vacation	21%	21%	21%	21%	21%
Total Loaded Hourly Rate:		Labourer	$ 25.84	$ 27.14	$ 27.95	$ 28.79	$ 31.00
		Equipment Operator - Entry	$ 26.84	$ 29.96	$ 30.78	$ 31.71	$ 34.31
		Supervisor / PLT Team lead	$ 55.53	$ 63.80	$ 65.57	$ 67.53	$ 73.08

Note 1 - This position is paid at the going hourly rate.
Note 2 - Per the Collective Agreement.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 55
Line and Service Jobs
Minimum Monthly (Hourly) Wage Ranges

2008

Job Class Number	Job Title	Wage Range Effective Jan. 1, 2007 (4.75)	Increment	Wage Range Effective Jan. 1, 2008 (4.5)	Increment
556100	Serviceman Lineman Journeyman	5,731-6,023 (32.94-34.61)	292 (1.68)	5,989-6,294 (34.42-36.17)	305 (1.75)
556300	Serviceman Lineman Journeyman (Maximum Range)	6,023-6,380 (34.61-36.67)	357 (2.05)	6,294-6,667 (36.17-38.32)	373 (2.14)
558100	Senior Serviceman Lead Lineman	6,083-6,959 (34.96-39.99)	292 (1.68)	6,357-7,272 (36.53-41.79)	305 (1.75)

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 57
General Operations Jobs
Minimum Monthly (Hourly) Wage Ranges

2008

Job Class Number	Job Title	Wage Range Effective Jan. 1, 2007 (3.5)	Increment	Wage Range Effective Jan. 1, 2008 (3.5)	Increment
570000	Labourer Groundman	Shall be paid the going hourly rate		Shall be paid the going hourly rate	
570100	Warehouseman	2,866-3,937 (16.47-22.63)	153 (.88)	2,968-4,074 (17.06-23.41)	158 (.91)
570300	Senior Warehouseman	3,784-4,396 (21.75-25.26)	153 (.88)	3,917-4,549 (22.51-26.14)	158 (.91)
570500	Stockkeeper	3,918-4,868 (22.52-27.98)	190 (1.09)	4,054-5,039 (23.30-28.96)	197 (1.13)
572100	Meter Reader	2,780-4,096 (15.98-23.54)	188 (1.08)	2,876-4,241 (16.53-24.37)	195 (1.12)
573000	Equipment Operator Entry Level	2,970-4,110 (17.07-23.62)	190 (1.09)	3,073-4,255 (17.66-24.45)	197 (1.13)
573100	Equipment Operator	4,121-4,978 (23.68-28.61)	190 (1.09)	4,265-5,153 (24.51-29.61)	197 (1.13)

1) Annual increments except those marked with an asterisk ( ) which are semi-annual.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 56
Plant Maintenance Jobs
Minimum Monthly (Hourly) Wage Ranges

Job Class Number	Job Title	Wage Range Effective Jan. 1, 2009 (5.25%)	Increment
566100	Maintenance Man I	2,992-4,887 (17.20-28.09)	*379 (*2.18)
566300	Maintenance Man II	4,907-6,044 (28.20-34.74)	*379 (*2.18)
566500	Maintenance Man III	6,055-7,192 (34.80-41.33)	*379 (*2.18)
566700	Lead Maintenance Man	7,454 (42.84)	

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

2009

THE YUKON ELECTRICAL COMPANY LIMIITED
SCHEDULE 57
General Operations Jobs
Minimum Monthly (Hourly) Wage Ranges

Job Class Number	Job Title	Wage Range Effective Jan. 1, 2009 (5.25%)	Increment
570000	Labourer/Groundman	Shall be paid the going hourly rate	
570100	Warehouseman	3,249-4,460 (18.67-25.63)	*173 (*0.99)
570300	Senior Warehouseman	4,288-4,980 (24.64-28.62)	*173 (*0.99)
570500	Stockkeeper	4,437-5,517 (25.50-31.71)	216 (1.24)
572100	Meter Reader	3,147-4,645 (18.09-26.70)	*214 (*1.23)
572300	Field Services Representative	3,360-4858 (19.31-27.92)	*214 (*1.23)
573000	Equipment Operator Entry Level	3,363-4,659 (19.33-26.78)	*216 (*1.24)
573100	Equipment Operator	4,668-5,642 (26.83-32.43)	*216 (*1.24)

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

2009

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 55
Line and Service Jobs
Minimum Monthly (Hourly) Wage Ranges

Job Class Number	Job Title	Wage Range Effective Jan. 1, 2009 (5.25%)	Increment
556110	Power Line Technician	6,745-7,509 (38.76-43.16)	*382 (*2.20)
558110	Power Line Technician Team Lead	7,161-8,190 (41.16-47.07)	305 (1.75)

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 54
Apprenticeship Jobs
Minimum Monthly (Hourly) Wage Ranges

Job Group Code(s)	Apprentice Journeyman Ticket Title	Training Term/Wage Range Effective January 1, 2009 (5.25%)							
		543101 1-1	543102 1-2	543103 2-1	543104 2-2	543105 3-1	543106 3-2	543107 4-1	543108 4-2
543101-543108	Power Line Technician	4,047 (23.26)	4,385 (25.20)	4,719 (27.12)	5,056 (29.06)	5,383 (30.99)	5,730 (32.93)	6,069 (34.88)	6,406 (36.82)

1) The Company Apprenticeship Guidelines set out all articles, conditions and administration necessary toward these apprenticeship arrangements.
2) Employees enrolled in recognized apprenticeship programs must successfully meet all apprenticeship requirements before being advanced.
3) When the Company enrolls an employee in a recognized apprenticeship program, the employee shall be reclassified to the applicable Journeyman Job classification upon successful completion of the full program and receipt of the Journeyman ticket.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 56 - Plant Maintenance Jobs
Plant Maintenance Jobs
Minimum Bi-Weekly Wage Ranges

2010 - 2012

Job Class Number	Job Title	Bi-Weekly Wage Range Jan 1, 2010 2.75%	Increment	Bi-Weekly Wage Range Jan 1, 2011 3.00%	Increment	Bi-Weekly Wage Range Jan 1, 2012 3.50%	Increment
566100	Maintenance Man I	1,414.05 - 2,309.33 (17.68 - 28.87)	*179.06 *2.24	1,456.65 - 2,378.90 (18.21 - 29.74)	*184.45 *2.31	1,507.93 - 2,462.65 (18.85 - 30.78)	*190.94 *2.39
566300	Maintenance Man II	2,318.38 - 2,856.04 (28.98 - 35.70)	*179.22 *2.24	2,388.22 - 2,942.08 (29.85 - 36.78)	*184.62 *2.31	2,472.30 - 3,045.66 (30.90 - 38.07)	*191.12 *2.39
566500	Maintenance Man III	2,860.98 - 3,397.82 (35.76 - 42.47)	*178.95 *2.24	2,947.16 - 3,500.18 (36.84 - 43.75)	*184.34 *2.30	3,050.91 - 3,623.41 (38.14 - 45.29)	*190.83 *2.39
566700	Lead Maintenance Man	3,521.96 44.02		3,628.06 45.35		3,755.79 46.95	

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 57
General Operations Jobs
Minimum Bi-Weekly Wage Ranges

Job Class Number	Job Title	Bi-Weekly Wage Range Jan. 1, 2010 2.75%	Increment	Bi-Weekly Wage Range Jan. 1, 2011 3.00%	Increment	Bi-Weekly Wage Range Jan. 1, 2012 3.50%	Increment
570000	Labourer/Groundman	Shall be paid the going hourly rate		Shall be paid the going hourly rate		Shall be paid the going hourly rate	
570100	Warehouseman	1,594.09 - 2,192.59 (19.93- 27.41)	*85.50 *1.07	1,642.11- 2,258.64 (20.53 – 28.23)	*88.08 *1.10	1,699.93 - 2,338.16 (21.25 – 29.23)	*91.18 *1.14
570300	Senior Warehouseman	2,104.63 - 2,446.63 (26.31 – 30.58)	*85.50 *1.07	2,168.03 - 2,520.33 (27.10 – 31.50)	*88.08 *1.10	2,244.36 - 2,609.06 (28.05 – 32.61)	*91.18 *1.14
570500	Stockkeeper	2,177.79 - 2,703.95 (27.22 – 33.80)	105.23 1.32	2,243.40 - 2,785.41 (28.04 – 34.82)	108.40 1.36	2,322.39 - 2,883.47 (29.03 – 36.04)	112.22 1.40
572100	Meter Reader	1,487.21 - 2,195.06 (18.59 - 27.44)	*101.12 *1.26	1,532.02 - 2,261.19 (19.15 - 28.26)	*104.17 *1.30	1,585.96 - 2,340.80 (19.82 - 29.26)	*107.83 *1.35
572300	Field Services Representative	1,587.52 - 2,295.36 (19.84 - 28.69)	*101.12 *1.26	1,635.35 - 2,364.51 (20.44 - 29.56)	*104.17 *1.30	1,692.93 - 2,447.75 (21.16 - 30.60)	*107.83 *1.35
573000	Equipment Operator Entry Level	1,589.16 - 2,201.64 (19.86 - 27.52)	102.08 1.28	1,637.04 - 2,267.97 (20.46 - 28.35)	105.16 1.31	1,694.68 - 2,347.82 (21.18 - 29.35)	108.86 1.36
573100	Equipment Operator	2,205.75 - 2,666.14 (27.57 - 33.33)	*115.10 *1.44	2,272.20 - 2,746.46 (28.40 - 34.33)	*118.57 *1.48	2,352.19 - 2,843.15 (29.40 - 35.54)	*122.74 *1.53

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

2010 - 2012

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 54
Apprentice Jobs
Minimum Bi-Weekly Wage Ranges

Job Class Code(s)	Apprentice Journeyman Ticket Title							
Training Term/Wage Range Effective January 1, 2010 Bi Weekly 2.75%								
		543101	543102	543103	543104	543105	543106	543107	543108
		1-1	1-2	2-1	2-2	3-1	3-2	4-1	4-2
543101-543108	Power Line Technician	1,912.26	2,071.74	2,229.59	2,389.08	2,547.75	2,707.24	2,867.56	3,027.04
		23.90	25.90	27.87	29.86	31.85	33.84	35.84	37.84
Training Term/Wage Range Effective January 1, 2011 Bi Weekly 3.00%									
		543101	543102	543103	543104	543105	543106	543107	543108
		1-1	1-2	2-1	2-2	3-1	3-2	4-1	4-2
543101-543108	Power Line Technician	1,969.87	2,134.15	2,296.76	2,461.06	2,624.50	2,788.80	2,953.95	3,118.23
		24.62	26.68	28.71	30.76	32.81	34.86	36.92	38.98
Training Term/Wage Range Effective January 1, 2012 Bi Weekly 3.50%									
		543101	543102	543103	543104	543105	543106	543107	543108
		1-1	1-2	2-1	2-2	3-1	3-2	4-1	4-2
543101-543108	Power Line Technician	2,039.22	2,209.29	2,377.62	2,547.71	2,716.89	2,886.99	3,057.94	3,228.01
		25.49	27.62	29.72	31.85	33.96	36.09	38.22	40.35

1) The Company Apprenticeship Guidelines set out all articles, conditions and administration necessary toward these apprenticeship arrangements.
2) Employees enrolled in recognized apprenticeship programs must successfully meet all apprenticeship requirements before being advanced.
3) When the Company enrolls an employee in a recognized apprenticeship program, the employee shall be reclassified to the applicable Journeyman Job classification upon successful completion of the full program and receipt of the Journeyman ticket.

THE YUKON ELECTRICAL COMPANY LIMITED
SCHEDULE 55
Line and Service Jobs
Minimum Bi-Weekly Wage Ranges

Job Class Number	Job Title	Bi-Weekly Wage Range Jan 1, 2010 2.75%	Increment	Bi-Weekly Wage Range Jan 1, 2011 3.00%	Increment	Bi-Weekly Wage Range Jan 1, 2012 3.50%	Increment
556110	Power Line Technician	3,186.54 - 3,548.27	*180.87	3,282.53 - 3,655.16	*186.32	3,398.10 - 3,783.84	*192.87
		(39.83 - 44.35)	*2.26	(41.03 - 45.69)	*2.33	(42.48 - 47.30)	*2.41
558110	Power Line Technician Team Lead	3,383.85 - 3,869.72	161.96	3,485.79 - 3,986.30	166.84	3,608.51 - 4,126.65	172.71
		(42.30 - 48.37)	2.02	(43.57 - 49.83)	2.09	(45.11 - 51.58)	2.16

1) Annual increments except those marked with an asterisk (*) which are semi-annual.

ATCO Electric	Company Division: Distribution Asset Management Target audience: District - Service areas	
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A. EXECUTIVE SUMMARY

ATCO Electric transmits and distributes electric energy to customers. ATCO Electric is regulated primarily by the Alberta Energy and Utilities Board (EUB) and under the Public Utilities Board Act, Electric Utilities Act, and Hydro and Electric Energy Act(HEEA). ATCO Electric's Distribution Team works in 37 offices across Alberta to deliver safe, reliable power by operating and maintaining more than 70,000 kilometers of power lines that bring electricity to more than 200 communities. More than 640,000 wood poles are available in our network for the support of power distribution lines, distribution equipment and street lights representing a value of about C$1.15 billion. Substituting wood with alternative materials like steel and construction methods would mean an increase in investment by 100 to 200% not including the attendant costs in handling and installation costs.

Untreated wood poles are susceptible to damage and failure caused by insects, fungi etc and hence prone to premature failure of structure thereby posing serious threat to network reliability and safety. Increase in average life span of wood poles due to treatment results in significant cost benefits achieved through deferment of pole replacement. So, wood poles are tested, treated with wood preservative pesticides and monitored periodically to ensure their healthiness.

Wood preservatives are pesticides. The registration and use of pesticides in Canada is regulated under the authority of the Pest Control Products Act (PCPA), administered by Health Canada through the Pest Management Regulatory Agency (PMRA). Other federal legislation affecting preserved wood includes the Transportation of Dangerous Goods Act which covers the movement of regulated quantities of chemicals, hazardous products and wastes, and the Fisheries Act which covers impacts of environmental contaminants on fish and fish habitat.

In addition, the application of pesticides is regulated through some provincial regimes. Provinces can enforce some aspects of federal legislation or can issue regulations, covering various points in the life cycle of treated wood which meet or exceed federal requirements. Our wood pole treatment procedures shall comply with the requirements of Alberta Environmental Protection and Enhancement Act and Regulations, Clean Water Act (Alberta Environment) and Clean Air Act (Alberta Environment).

The Distribution Wood Pole Asset Management Guidelines are applicable to all wood poles under the scope of our maintenance program. Our Wood Pole Asset Management Program has developed over the years to achieve service life extension of wood poles economically without compromising on safety, quality and reliability.

Part-1 Wood Pole Asset Management

1.0 INTRODUCTION

The guidelines for Wood Pole Asset Management Program are based on engineering, environmental and operational requirements. They ensure uniformity in test, treatment procedures and quality control.

1.1 Purpose

The purpose of these guidelines is to achieve optimum asset life cycle management of all distribution wood poles. It will enable us to ensure that the purchases are made wisely making the best use of available resources and that we protect these investments by maintaining them in good service condition.

1.2 Strategy

The overall Asset Management strategy shall be cost effective without compromising on the safety, reliability and quality of service to our customers. It shall take into consideration the latest regulations and standards applicable and it shall be competitive as compared to the strategies adopted by the best utilities in North America.

The maintenance strategy employed shall be Reliability Centered Maintenance employing Failure Mode Causes and Effects Analysis, Root Cause Failure Analysis, Preventive/Proactive maintenance plans and Total Quality Management (TQM).

1.3 Objectives

a. Effective life cycle management of wood pole assets.
b. Optimize utilization of field resources
c. To standardize the management of wood poles across the organization through application of quality control measures, test procedures and maintenance techniques.
d. Proper documentation of policies, procedures and activities related to life cycle of wood poles in order to monitor, review and justify the fund plans.
e. To ensure that the program aligns with the organizational and departmental business objectives.

2.0 UTILITY WOOD POLE - LIFE CYCLE STAGES & STANDARDS

2.1 Pole selection:

Selection of wood pole shall be according to specification S31 in the latest version of Distribution Construction Standards Manual. Also the manufacturer, physical properties, method of treatment, dimensions and inspection method shall be as per this specification.

Unless specified otherwise in the Distribution Construction Standards manual, the poles shall meet the following criteria.

1. Pole material requirement - ANSI O5.1, AWPA U1-09
2. Preservative treatment - AWPA T1-09
3. Engineering design stresses (Design values) - CSA O15-05

Glued-laminated poles, if chosen for special applications and shape shall be as per ANSI O5.2 standard. The critical mechanical properties for wood pole include the sweep and crook properties of the poles and shall meet the limit requirements specified in ANSI O5.1 and ASTMD25. Pole structure design shall be as per ANSI C2.

Material evaluation shall include an assessment of availability. Locally available species of timber in acceptable form and quality shall be preferred. The other traits for consideration include thick and easily treated sapwood, favorable strength properties & form and availability in popular pole sizes.

The preferred wood species are Western Red Cedar, Alaska Yellow Cedar, Lodge Pole Pine, Jack Pine and any other species with written authorization from the purchasing utility.

2.2 Critical properties of wood:

The elastic properties of wood measure its ability to recover completely from its deformations due to low stresses after removal of loads. Elasticity is defined by modulus of elasticity, modulus of rigidity and Poisson's ratio. These properties vary within and between species and with moisture content and specific gravity.

Mechanical properties related to structural strength of wood include modulus of rupture in bending, maximum stress in compression parallel to grain, compressive stress perpendicular to grain and shear strength parallel to grain.

The test methods used to establish the strength and mechanical properties shall be based on standard test procedures in ASTM D143.

Some natural characteristics affecting mechanical strength of wood poles are specific gravity, knots, slope of grain, annual ring orientation, reaction of wood, juvenile wood, pitch pockets, bird peck, compression failure and extractives.

Manufacturing and service environment factors affecting strength of wood poles are moisture content, temperature, duration of load, fatigue, ageing, preservative treatment, mold and stain fungi, decay and insect damage.

ANSI – American National Standards Institute; **AWPA** – American Wood-Preserver's Association. **ASTM** – American Society for Testing and Materials.

2.3 Preparation and treatment of timber for utility poles:

The wood preservation processes are aimed at injecting requisite amounts of preservative liquids deep into the wood to provide long term protection against wood-destroying insects and fungi. The majority of wood preservation is through pressure impregnation process and non-pressure treatments are of secondary importance.

Wood preservatives may be classified as

i) Oil borne preservatives, such as creosote, petroleum solutions of pentachlorophenol and copper naphthenate.
ii) Waterborne preservatives are those applied as water solutions; standard wood preservatives used in water solution include ammoniacal copper arsenate (ACA), ammoniacal copper zinc arsenate (ACZA), or chromated copper arsenate (CCA) (Types A and C)

The poles shall be treated with one of the following preservatives –

a. Chromated Copper Arsenate (CCA) Type C – AWPA P23-08
b. Copper Naphthenate dissolved in hydrocarbon solvent - CAN/CSA-080.201.

The choice of wood preservatives depends upon the character of the wood to be treated, the anticipated service and the properties of the chemical or formulation. Wood preservation formulations must:

- protect against attacking organisms;
- be able to penetrate wood;
- remain in the wood for the length of the intended service;
- be chemically stable;
- be safe to handle;
- be economical to use;
- not weaken structural strength;
- not cause significant dimensional changes within the wood.

Other factors that determine selection of chemicals or formulations include fire resistance, color or odor; paint ability, corrosiveness, electrical conductivity and environmental considerations.

The effectiveness of preservatives is influenced not only by the protective value of the preservative chemical, but also by the method of application and extent of penetration and retention of the preservative in the treated wood. Even with an effective preservative, good protection cannot be expected with poor penetration or substandard retention levels. Higher retention levels are justified in poles to be installed under severe climatic or exposure conditions.

The key factors of preservative treatment are preservative chemistry (type of chemical), preservative retention, initial kiln-drying temperature, post-treatment drying temperature and pretreatment incising.

Peeling is necessary to enable the wood to dry quickly enough to avoid decay and insect damage and to permit the preservative to penetrate satisfactorily. Drying of wood before treatment is necessary to prevent decay and stain and to obtain preservative penetration. Kiln drying has the important added advantage of quickly reducing moisture content, thereby reducing transportation charges on poles. When green wood is to be treated under pressure, steaming-and-vacuum process or boiling-under-vacuum

(Boulton) process is used. The Boulton method removes much less moisture from heartwood than from sapwood.
Wood that is resistant to penetration by preservatives may be incised before treatment to permit deeper and more uniform penetration. The effectiveness of incising depends on the fact that preservatives usually penetrate into wood much farther in the longitudinal direction than in a direction perpendicular to the faces of the timber. Incising is especially effective in improving penetration in the heartwood areas of sawn surfaces.

Three pressure processes are commonly used: full-cell, modified full-cell, and empty-cell. The full-cell (Bethel) process is used when the retention of a maximum quantity of preservative is desired. The modified full-cell process is basically the same as the full-cell process except for the amount of initial vacuum and the occasional use of an extended final vacuum. The objective of the empty-cell process is to obtain deep penetration with a relatively low net retention of preservative. For treatment with oil preservatives, the empty-cell process should always be used if it will provide the desired retention. Complete penetration of the sapwood should be the ideal in all pressure treatments.

2.4 Quality Assurance for Treated Wood

The AWPA Processing and Treatment Standard T1-09, specifies the processing and treatment requirements. It also specifies the minimum requirements for preservative penetration and retention levels and recommendations for handling wood after treatment to provide a quality product.

2.5 Inspection

There are two important factors to consider depending upon the intended end use of preservative-treated wood: (a) the grade or appearance of the lumber and (b) the quality of the preservative treatment in the lumber. Poles to be used in sensitive environments shall be produced in compliance with Best Management Practices (BMPs) specified by Western Wood Preservers Institute (WWPI). The inspection of pole material should be in accordance with the AWPA standards M2-07- "Standard for Inspection of Wood Products Treated with Preservatives".

2.6 Purchase of Treated Wood

The appropriate specifications to obtain a treated-wood product of high quality shall be as per AWPA standards U1-09 6D (commodity specification for poles) and AWPA standards M1-08 – "Standard for the Purchase of Treated Wood Products".

2.7 Handling and installation of poles

Wood treated with preservative oils should generally be installed as soon as practicable after treatment to minimize lateral movement of the preservative, but sometimes cleanliness of the surface can be improved by exposing the treated wood to the weather for a limited time before installation. Waterborne preservatives or copper naphthenate in a volatile solvent are best suited to uses where cleanliness or paintability is of great importance.
Unsheltered exterior storage of treated wood for long periods before installation should be avoided because such storage encourages deep and detrimental checking and can also result in significant loss of some preservatives. Treated wood that must be stored before use should be covered for protection from the sun and weather.

Although cutting wood after treatment is highly undesirable, it cannot always be avoided. When cutting is necessary, the damage can be partly overcome in timber for land or freshwater use by a thorough application of copper naphthenate (2% copper) to the cut surface. This provides a protective coating of preservative on the surface that may slowly migrate into the end grain of the wood. AWPA M4-08 standards – "Care Of Preservative-Treated Wood Products" shall be applicable.

2.8 Treatment of in-service poles

In treatments of standing poles, the preservative can be injected into the pole at groundline with a special tool or applied on the pole surface as a paste/bandage or poured into holes bored in the pole at the groundline. These treatments have recognized value for application to untreated standing poles and treated poles where preservative retention levels are determined to be inadequate. The applicable guidelines are as per AWPA M13-07 – "Guidelines for a Pole Maintenance Program".

3.0 WOOD POLE TEST AND TREAT PROGRAM

3.1 Program Schedule

Test and treat program for all wood pole structures is being carried out on a nine-year cycle based on the observed retention level of preservatives in poles over the years.

For efficiency each plant is to be fully completed and any small plant within the larger plant will be completed. n the case of numbered lines, it is recommended to complete each complete line as one project that feeds or is within the boundaries of the plants being work on. Working from one switching device to another will help avoid overlapping outages for pole changes.

The pole plant maintenance schedule shall be based on previous test and treat cycles and line patrol findings. Rotation can be adjusted, if found necessary.

Each year, use the pole plant maintenance schedule to prepare maps indicating the lines to be tested, treated and recorded according to specific property numbers and/or line ownership (e.g., R.E.A.L poles, oilfield poles, '5L' distribution line poles, etc)

The second cycle of program shall be based on the first cycle with suitable changes made wherever required.

3.2 Two-Step Program

The program consists of two steps – test & treat.
The R.E.A.L offices need to be intimated in advance through the region CSS for necessary approval to proceed in their areas. (If an REA declines the test & treat, Atco will still test the poles)
All poles owned by ATCO Electric or R.E.A.L should be tested and treated, according to schedule requirements. Customer-owned poles are excluded from the schedule.
The availability of pole species and their treatment methods vary by region and service area. (Refer Appendix A: Pole Identification).
The existing test & treat database to be verified for identifying poles which have been treated on more than one occasion. In general, bandages should be applied to:

- All poles identified for treatment during the course of the test and treat program (Explained in detail in Part-2, section 4.0);
- All poles that have been partially excavated or reset;
- Butt-treated poles where the ground level has been raised above the commercially treated area and
- Full Length Pressure Treated (F.L.P.T.) poles, which no longer have sufficient preservative to prevent decay.

A reasonable estimate of the remaining service life of F.L.P.T. poles can be attained by analyzing the core samples to determine the amount of preservative retained. In the case of butt treated poles, most of which are over 40 years old, a field examination will be adequate.

3.2.1 Pole Plant Test and Treat Priority

The following poles have been prioritized for treatment has been established on the basis of previous test & treat results and information from utility industry.

A. Previously Untreated Poles.

B. Butt Treated Poles

Also the pole records indicate the variation in effectiveness of treatment among different species. The detailed test and treat requirements are specified in Part-2 section 4.1.

a. Fir & Larch species

Additional efforts may be required in locating fir poles and if located, a permanent record should be kept for future reference.

Due to density, these species have a very thin shell of originally treated wood. A first time ground line bandage should be installed after poles have been in service 20 years

If Hollow Heart is found, and the pole has adequate shell strength, the poles should be given an internal treatment. In case the poles have been affected by pole top decay, the Wood Pole Strength Table (Appendix B) shall be used to determine the remaining strength and decide whether it needs replacement.

b. Pine

In general, Pine poles have received the original treatment well. A first time ground line bandage should be installed after the poles have been in service for 20 years.

Pine poles should be tested for Hollow Heart. If strength is adequate, an internal treatment should be administered. If above ground decay has advanced to an unsafe condition, the pole should be replaced. These poles should be re-examined every nine years and re-treated, if required.

c. Butt Treated Western Red Cedar

Decay in these poles will be greatest at ground line and usually external. If the decay is not too far advanced, a ground line bandage should be installed as cedar readily accepts re-treatment. If decay has advanced beyond recommended limits, the pole should be replaced.

If internal decay is discovered and the pole has adequate strength, an internal treatment should be administered. These poles should be re-examined every nine years and retreated, if justified.

C. Full Length Pressure Treated (F.L.P.T.) Poles

In general, FLPT poles with oil-based preservative provide a service life of 20 - 30 years before preservative retention levels drop below the acceptable levels. The relevant standards to measure the level of preservative retentions are ASTM D5583-94 & AWPA – A12-09. When poles are relocated, or have their ground line changed, they shall be retreated. Random sampling for assays should be carried out by persons who are properly trained in sampling and handling methods. The reports should specify the nature of corrective treatment required and identify further tests, if any, required. Poles procured in the last three decades have been mostly treated with water based

preservative (CCA etc.) and preferably require retreatment after 20 years to maintain the preservative content to required level.

The following program shall be adhered to for testing and treating of full-length pressure treated wood poles:

Species	1st Test & Treatment	2nd & Subsequent Tests
Fir & Larch	First test cycle after 20 years	9 year cycle
Pine	First test cycle after 20 years	9 year cycle
Cedar	First test cycle after 20 years	9 year cycle

3.2.2 Test and Treat Program Outline

: #	Group	Test (drill) & record	Treat internally	Apply bandage	Visual inspection, sound & record	Remarks
1	Butt treated poles	√	√*	*	√	*if required
2	F.L.P.T. poles aged 20years or more	√	√	√ #	√	# If not done earlier
3	F.L.P.T. poles aged 10 years or more, but below 20 years					
	a. 10 % poles at random	√	√	-	√	
	b. Remaining 90% poles	-	-	-	√	
4	F.L.P.T. poles aged less than 10 years	-	-	-	√	

Test and Treat technical details are provided in Part-2 of this manual.

4. DOCUMENTATION

To aid contract inspectors in identifying line ownership, a color-coded map with legend must be prepared prior to the start-up meeting.

- Pole inspectors are to record all poles using the Electronic Pole Inspection Report Form All inspection data, treatment and recommended actions must be recorded.
- Inspectors are required to send the completed electronic Pole Inspection data base to the ATCO Electric D.A.M. Supervisor.
- The Pole Inspection data base will be used to administer the test and treat contract payment.
- The Pole inspection data base will define the scope of the pole change and stubbing requirements. The information can also be used for manpower planning and to define material, equipment and outage requirements.

4.1 Invoicing

To assist in assigning expenses to the appropriate budget (O&M or Capital), the contractor invoices will provide a breakdown of test and treat activities based on pole age. (Refer Part-2, section 3.0 for details).

This distinction is necessary because testing does not increase the life expectancy of poles, and is therefore deemed a maintenance cost. However, treating poles does add life expectancy to the pole plant system and is therefore deemed a capital expense.

4.2 T&T Invoice Verification Process

- Match "miles" indicated on master map with "miles" documented on hardcopy or electronic record.
- Verify that number of poles per master map "mile" approximate to the numbers indicated in the records [sequence number].
- Verify that poles sequence numbers on urban master maps match sequence numbers in the records.
- Verify ownership indicated in record as REA or AE matches color coding on master map.
- Match tasks indicated on invoice with tasks indicated in appropriate Pole Admin. Electronic version "Action Count Report".
- Review all information documented per pole for accuracy on a random selection basis [5% to 6% of each plant number] i.e. land location, treatment, etc.
- Verify calculation, original circumference – decay deduction = present circumference.
- Verify that required circumference is accurate as per wind load chart Appendix B, Table H-11-4 in program.
- Remember
    - *O&M tasks are indicated as such on upper left side of invoices
    - *Capital tasks are indicated as such on lower left side of invoices

5.0 QUALITY CONTROL

5.1 Quality Control Audit

A quality control audit is to be completed to make sure contractors hired to carry out test and treat within the distribution system are doing quality work and are completing all requirements as described in Part-2, section 4.0.

The audit includes:

- Completing a random (one percent to two percent) sampling of the test population to check that proper drilling, plugging and tagging has been completed on poles that are to remain in service.
- Completing a random (one percent to two percent) sampling of the population to check that proper drilling, plugging and tagging for internal treatment has occurred.
- Completing a random (one percent to two percent) sampling of the population to check that pole bandages were properly applied.

Test and Treat Audit Form is provided in Appendix E.

- Ensure all poles are in REAs are inspected

5.2 Safety

ATCO Electric Supervisor or designee will complete a weekly work site visit and ATCO Electric Job Observation form "Review of Worksite Safe Work Performance" (refer to the AE Intranet, Health & Safety Forms and Reports) and return to appropriate D.A.M Edmonton clerk. All audits to be sent to contractor office also

5.2.1. ATV / OHV:

All contract personnel are to be formally trained in operations and hazards associated with ATV operation. A training certificate or letter stating that the individuals are trained is to be submitted to ATCO Electric.

When operating an ATV or snow vehicle as defined in the off-highway vehicle act, the worker shall wear protective headgear approved by one of the following organizations for use as protective headwear in motor vehicle applications:

(a) Canadian Standards Association (CSA CAN3-D230-M85)
(b) American National Standards Institute (ANSI)
(c) Snell Memorial Foundation
(d) British Standards Institution

5.2.2. Safety Glasses:

Approved safety glasses are to be worn by Test and Treat personnel while performing all tasks associated with testing and treating of poles.

5.2.3. First Aid:

Field locations have specified hazards deemed High Risk Hazards and will require the following for each truck in the field:

- One #2 First Aid Kit
- Each crew member is a holder of Standard First Aid Certificate????

5.2.4. Restricted Sites:

All Test and Treat personnel shall be familiar with the procedures (ATCO Electric Safe Practices Manual) working in or around H_2S sites.

5.2.5. Clothing:

Test and Treat crews shall have F.R.C clothing readily available and shall wear the same when insisted by ATCO Electric.

5.2.6. Underground Service Risers:

No excavations will be attempted by test and treat crew personnel at poles with under ground services attached unless they are Qualified Utility Journeymen. (See Part-2, Section-2.3 for details)

5.2.7. WHIMIS/TDG:

All lead testers shall have valid Workplace Hazardous Materials Information System (WHIMIS) certificate. A valid Transportation of Dangerous Goods (TDG) certificate is required, if the crews are handling or shipping any hazardous material.

6.0 Construction Lead RESPONSIBILITIES

Responsibilities of the Construction Lead shall include the following activities.

- Review and assist the Project Manager in preparation of program schedule,
- Ensure the concerned Team Lead, was contacted by the contractor supervisor to review the schedule and arranged a start up meeting in each District
- Attend start up meeting with contract crew and the concerned D.A.M. Supervisor & assist with competency verification of new crews
- Contractor supervisor to complete weekly status report detailing targets and achievements
- Identify future scheduling and completion requirements with D.A.M. Supervisor
- Report safety and quality lapses, if any, to D.A.M. Supervisor as soon as possible and shall stop work, if necessary, to help rectify the lapses.
- Assist contractor crews with any additional information regarding specific districts in their daily tailboards
- Ensure that government legislated and ATCO Electric Safe Work Environmental Practices and Procedures are understood and adhered to by contractor.
- Update the D.A.M. Supervisor of any incidents, personal, vehicle, environmental or customer related
- Follow up on any further requests regarding incident reports
- Ensure contract supervisor is following reporting in requirements of the TDSOP
- Ensure contract crews are completing accurate and concise inspection reports and master maps as per the program requirement
- Monitor accuracy of work and safety of random crews by completing a biweekly work activity check as per Appendix E Test and Treat Audit Form
- Audit completed work for Quality control as per item 5.1
- Ensure familiarity of personnel with the program technical details on an ongoing basis
- Assist D.A.M. Supervisors with interpretation of records and invoices when required
- Coordinate/execute other duties as required

7.0 BUDGETING

The current rate for internal treat (Rod/ Boracol) is to be ascertained from O&M.

Sl. No.	Test & Treat	O&M Exp.	Cap. Exp.
1.	Test & Record	√	
2.	Inspect, Re-treat & Record		√
3.	Re-treat & Record		√
4.	Internal Treat & Record		√
5.	Field Check for replacement work order prep		√
6.	Prep Replacement work order		√

Part-2 – Test and Treat Technical Detail

1. General

1.1 Qualifications

LEAD INSPECTOR shall be well trained to recognize decay and other defects, calculate wood pole strength from the tables in the appendices, identify the pole species, prepare the field report and organize the work. They shall hold a valid driver's license and be well versed in dealing with property owners.

ASSISTANT INSPECTOR shall train under a Lead Inspector until they become competent in all aspects of decay and other defect interpretation, wood pole strength determination, pole species identification and are able to perform independently. The period of training will usually be about 5000 poles under direct supervision.

LABORER must be physically fit to undertake the rigorous work of excavation and back filling. Laborer will be knowledgeable in product application and job quality. Shall be able to recognize the obvious rejects and exercise caution where called for, such as on poles with underground services.

CONTRACTOR shall have a current and recognized Safety Program. ATCO Electric and contract personnel are to obtain permission prior to entering private property.

TESTING includes visual inspection, sound testing, excavation and drilling to determine if the pole has sufficient strength to support the load it carries. Poles requiring testing include:

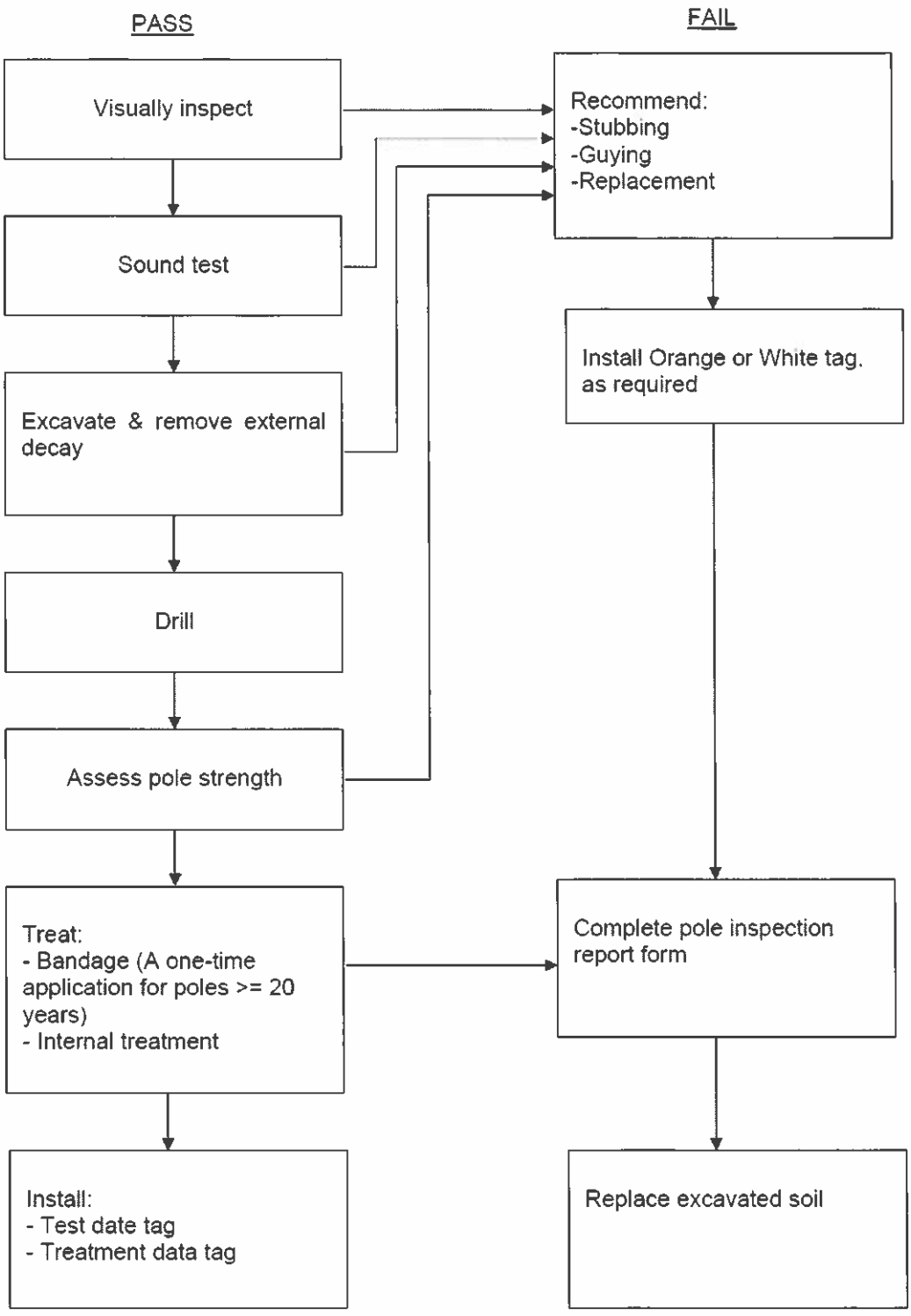
- In-service poles scheduled for test and treat.
- Poles which are to bear additional loads.
- Poles in doubtful condition.

TREATMENT means the application of a preservative to prevent decay.
Pole testing and treating, should be done only by trained and competent personnel.

2.0 Process

The steps involved in the pole test & treat process are as shown below. In case of any pole failure during the process, further testing is to be aborted and the recommendations made for further action to be followed.

TEST AND TREAT FLOW CHART



2.1 Visual Inspection

A thorough inspection above groundline is done first to detect defects such as split tops, through checks, lightning damage, shrinkage or discoloration at the top of poles. Defects should be reported on the Pole Inspection Report form so that further investigation can be made by a lineman. Broken poles, including poles with cracks or cross breaks, should be immediately condemned for replacement.

Sawdust in checks or on the ground at base of pole is indicative of the presence of carpenter ants or bees in the upper part of pole. If present, continue with sound testing and drilling to determine the extent of the damage.

2.2 Sound Testing

Sound testing is used to detect decay inside the pole. Use a hammer to strike the pole around the sides from the ground line to about eight feet above the ground line. The minimum number of sounding marks per pole required is as follows: Four sounding marks in the first foot of poles starting at ground line (one in each quadrant of the pole). Twelve sounding marks in the remaining height of the pole should be evenly distributed in all four quadrants of the pole. If a pocket is detected at a particular sounding mark, then additional sounding will be required. The hammer blow will usually detect rot immediately below the surface by breaking the thin outer shell of sound wood. Remove this as external decay.

2.3 Excavation/ Divot

The following precautions are required before undertaking excavation around poles.

1. No excavations to be under taken on poles with underground cables attached
2. No excavations required around poles encased in cement or pavement.

The test holes in this case (maximum of 3 holes regardless of circumference) will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm - 400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.

Divot the base of the pole, to a minimum of six inches to expose decay below the ground line. Decayed wood on the surface can best be detected by inserting a knife blade about 1/8 of an inch below the surface and prying a splinter loose. If the splinter pulls along the grain from the wood, the wood is sound. If the wood is broken without forming a splinter, the wood should be considered decayed.

2.4 Probing

Probing is used to detect decay in checks and exposed pockets. It is done with a piece of steel wire 6 inches long and about 1/8th of an inch in diameter (the reinforcing wire from scrap ACSR is ideal). Jabbing sharpened bars or claws of hammer into the surface of a pole is prohibited as this may damage fungus resistant wood and allow decay to start in less resistant areas. The surface of the pole should be probed

concentrating on areas near and in deep checks. If the wood is felt to yield under pressure, decay should be suspected.

All external decay, including decay in enclosed pockets and checks, must be removed before taking circumference measurements. If decayed wood is included in these measurements, the strength of the pole will be over-estimated. Also, decayed wood on the surface or in pockets may deprive sound wood of treatment. Suitable tools for removing decay include scrapers, wire brush, hatchet, and wood chisel.

Take care not to remove sound wood as this will weaken the pole. After removing the decay, form a taper to about 6"above the ground line to provide a smooth surface.

2.5 Drilling – Hollow Heart, Effective Shell Thickness

The following precautions are required before undertaking excavation around poles.

1. No excavations to be under taken on poles with underground cables attached.
2. No excavations required around poles encased in cement or pavement.

The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.

To detect Hollow Heart, the pole should be drilled at least three times at a minimum depth of 6" below ground, angling the bit at 45° drilling toward the center at the N, SW and SE quadrants. The drill is to be 12.5 mm (1/2"). Depth of bore should be 200-250 mm minimum depending on circumference of pole.

While drilling, note any change in the rate of the penetration of the drill – the sudden collapse of wood under the drill indicates decay. Powdery borings also indicate decayed wood.

After completing three drillings, measure the length of sound wood in each hole using the shell thickness indicator or another acceptable method. The radial thickness of sound wood in the shell is calculated by multiplying these measurements by 2/3. To find the "Effective Shell Thickness," disregard the largest thickness and take the average of the two smaller thicknesses.

For example:

The lengths of sound wood in each boring have been measured at 7-1/2", 6" and 3-3/4".

Thickness of the shell at each boring:

Boring 1: 7 ½" X 2/3 = 5"

Boring 2: 6" X 2/3 = 4"

Boring 3: 3 ¾ X 2/3 = 2 ½"

Disregard the largest reading. Take the average of the two smaller readings:

Average: (4" +2 ½")/2 = 3 ¼"

Refer to Appendix B, Wood Pole Strength Table H-11-4, for Hollow Heart Deductions of Pole Strength. Deductions for shell thickness are provided in ½" increments. Find the nearest measurement BELOW the average reading of 3 ¼". Deduct the corresponding allowance from the minimum measured circumference to determine the Hollow Heart effective shell thickness.

Poles with a shell thickness of less than two inches are to be condemned. (RED tagged)

Pole with a shell thickness of less than one inch are to be condemned. (white tagged)

If the pole is to be maintained in service, all drilled holes must be plugged with oversized plastic plugs. If this plugging is not done, decay organisms will have easy access to wood, which may be less decay resistant. A supply of 2" long plastic plugs is required for plugging holes.

2.6 Pole Strength Assessment

After external decay has been removed and drilling is completed, measurements to assess strength are made as follows:

- **Minimum Measured Circumference**

On poles where there has been no loss of wood, a thin (1/4"wide) flexible metal tape should be drawn tightly round the pole at the ground line; this measurement will be the "minimum measured circumference."

On poles that have been cleared of rot near the ground line, the measurement should be made over the trimmed portion. A series of measurements down the trimmed portion (may be required to determine the smallest measurement. This smallest measurement will be the "minimum measured circumference."

- **Exposed Pockets**

The width and depth of all exposed pockets should be measured. The length of the pockets along the pole axis is not significant.

Measure the width of the pocket at its widest point. If the pocket widens below the surface of the pole, estimate this width.

Measure the depth of pocket (the distance across the growth rings toward the center of the pole) by tightly drawing the measuring tape from the surface opening of the pocket to the sound wood inside the pole.
After each exposed pocket has been measured, deduct pocket allowances from the minimum measured circumference (i.e. pocket or pockets)

- **Effective Circumference & Required Circumference**

The Effective Circumference of a pole is a measure of its actual strength. It is found by deducting allowances for exposed pockets and Hollow Heart from the minimum measured circumference.
The Required Circumference is a measure of pole strength necessary to support its conductors and other attachments. Appendix B: Wood Pole Strength Table H-11-4 gives the basis for calculating these requirements.
When a line is to be inspected, note the factors common to each pole. For example, the line might be constructed on 40-foot poles in a heavy loading area with three-phase 3/0 conductors at 250-foot spans.
The required circumference for most poles is calculated as follows: Heavy loading used only on Butt treat.

Starting Circumference	**24.5"**
Load Factors: Heavy Load Area(butt treat only)	+ 3.0"
Three-Phase Primary	+ 4.0"
Required Circumference	**31.5"**

For additional loading, add the allowance to the basic 31.5". For example, adding two secondary conductors will add 2" to the required circumference (1" each), for a total of 33.5".

If the Effective Circumference is equal to or greater than the Required Circumference (that is, the pole is strong enough to support its load), recommend treatment, depending on pole age.

- **Assessing Above-ground Strength**

The procedures outlined above are usually adequate for assessing the strength of a pole. However, there may be circumstances when it becomes necessary to check the strength of the above-ground portion of the pole. These circumstances include:

a. When a line is to be loaded with three phase or larger conductor, or when heavy banks of transformers are to be installed.
b. When there has been no ground line deterioration, but sapwood has rotted on the above-ground surface of the pole.
c. When poles appear to have extreme taper, rot or obvious damage such as bird holes.

Assess the required strength halfway up by multiplying the ground line circumference by 0.8. The required strength at the top of the pole can be assessed by multiplying the ground line circumference by 0.6.

If there are decay pockets in these areas, use the Wood Pole Strength Table (Appendix B) to make the necessary deductions.

2.7 Treatment

If the pole has sufficient strength, proceed with treatment as per the requirements in section 4.0. Further information on specific treatments is available in Appendix F. Material used in test and treat program shall meet specification No. S27 (Rev. no. 1)

2.6.1 External Treatment (Bandage)

External treatment involves the application of a preservative bandage below the ground line to prevent ingress of fungus and insects for 20 years.

Bandage Requirements:

1. The bandage shall be S.D. 49.53 cm wide (19.5 "), such that a layer of preservative 44.45-cm (17.5") wide is applied to the pole.
2. Active ingredients may include copper, copper naphthenate and borax and shall meet the relevant AWPA preservative standards.
3. Copper Naphthenate based greases require a grease thickness of 6.35 mm.

Bandage Application:

1. Bandage application will be done for all poles at the first test cycle after they have been installed for 20 years or more, on a one-time basis.
2. To prepare the pole, excavate to a minimum depth of 20.5" below ground line, allowing wrap to extend 2" above ground level. (Remove dirt and decay from pole surface), remove all external decay and any decay in exposed pockets. If the pole is set in a lawn or pasture, continue the excavation to a minimum depth of 20.5" so that when work is completed, the top of the bandage will be at ground level.
   (If the surrounding area is pavement or concrete or have live underground service cables, apply an internal treatment instead of a bandage.)
2. Measure the circumference of the pole 2"above the ground line. Cut the bandage at a separation point that allows for this length plus 2" to 6" for overlap.
3. Apply wrap over ground wire.
4. Lower the bandage into the excavation and place around the pole, smoothing against the pole surface and using the overlap to draw the bandage tight at the top. Do not apply excessive pressure that might displace the preservative. (It may be helpful to have a coworker assist in this part of the operation.)

5. Staple the top edge of the bandage to the pole, overlapping the ends. Use a hand tacker rather than a hammer as a hammer blow might cause preservative to be splashed.
6. Backfill the excavation, being careful to protect the bandage from large rocks by placing the face of a spade against it. Recommended to use hand tamper to ensure unsupported pole does not come over.
7. When the application is complete, the top of the bandage should be about 2" above ground level except in lawns and pasture, where the top of the bandage should be level with the ground.
8. Attach a product identification tag (Appendix-R) to the pole at eye level on the roadside face to show the bandage.
   (See Appendix G for diagrams.)

2.6.2 Internal Treatment

Apply to all poles with Internal Decay (Hollow Heart & Heart Rot) resulting from decay or insect infestation. This treatment is effective for eight to ten years.

Treatment requirements:

Internal treatment consists of a boron rod or fumigant (Cobra rod and Timbor professional) applied as described below. Active ingredients may include copper, copper naphthenate, anhydrous disodium octaborate, disodium octaborate, tetrahydrate & anhydrous sodium and shall meet the latest AWPA preservative standards applicable.

Treatment application:

Internal Treatment Application:

Application efficacy is dependent on initial treatment load rates and the preservative's ability to lock into the wood cell structure. Internal pole treatment with a copper/boron, water soluble diffusible co-biocide is a proven system to effectively control and prevent the internal infestation of wooden utility poles by various forms of fungal spores and insects. Using this method, an initial load rate is 6kg. /M^3 of BAE equivalent copper/boron complex will be adequate to establish an 8-10 year efficacy term.

Installation instructions:

Follow the label instruction and insert 1-10 mm X 120mm copper/boron rod in each of the three previously drilled inspection holes located 6" below ground line. Tightly plug with an oversized treated plastic plug. The plug must be removable to permit Q.C. inspection and also to re-access the hole to do subsequent re-treatment without drilling extra holes. If the poles circumference (see Table #1 below) dictates the necessity for more than 3 rods, an additional treatment zone will be developed at the ground line zone unless pole is in pavement or concrete.

Drill a second trio of three additional holes starting at ground line using compass points South (S), NE, and NW, to alternate with the holes drilled below. Prior to drilling these holes measure the circumference to determine if one rod per hole is sufficient or whether an additional rod per hole will be required to achieve the toxic loading desired. This decision will determine the proper drill depth for either one or two rods per hole in the second tier of holes. These holes are drilled at the ground line. This drill pattern and hole location will allow the migration of the active ingredients within the pole to dome up to the upper threshold and down to the lower levels (18") below ground line. This application procedure is in compliance with label instructions, manufacturers labeling and ATCO Electric Appendix 1.

Table #1:

Pole Circumference	Treatment
Up to and including 34"	- 3 rods, one per hole
35" to 39"	- 6 rods, two per hole
40" and greater	- 9 rods, three per hole

See Appendix I for the recommended drilling pattern. Drill to be 12.5 mm (1/2")

2.6.2.1 Internal Flood

Depending on the results of the test at each applicable pole, a field decision will be made by the tester to internal flood the pole to destroy or inhibit active fungus or insects at or above the ground line area. A minimum of 0.5 liters of liquid Boron (10% in-solution and purity as per AWPA standards) will be injected into each pole to accomplish this, as follows. Start at the 6" above ground line level and continue up the pole at 6" intervals, in a spiral fashion until beyond the infestation area. Under normal conditions a maximum of 3 holes up to 18" above ground line will be sufficient. These holes will be drilled with a 19 mm bit to a depth of 10"-12" and bore cleaned of all cuttings, filled, then plugged with an oversized treated, removable plastic plug. To ensure each pole receives the required amount of liquid treatment, ensure product is injected slowly and that no air pockets are created to give the false impression that the bore is filled.

2.6.3 Other Recommendations

While treatment is to be completed by the pole inspector, decisions on type of stub, guying, or will usually rest with the supervisor.

- **Stubbing**

Stubbing is recommended only as a last resort measure to keep the pole in service where it cannot be replaced due to constraints like non-availability of outage, busy 4-way pole that should be redesigned etc. Poles considered ideal candidates for stubbing should meet the requirement that the pole shell and heart are in good condition with no shell, heart, or butt rot present, starting from 12" above ground and

proceeding up the poles and from 12" below ground and down, to provide a solid surface for the stub to align itself to.

- **Guying**

Where poles are inadequate because of side load due to unsupported services, guying should be recommended. With guying, treatment or stubbing may be adequate to maintain the poles in service.

- **Replacement**

These include broken poles, poles that have both internal and external decay at the ground line area and poles that have Hollow Heart with effective shell thickness less than two inches. Poles in this condition have deteriorated where they have become unsafe and are not economical to maintain.

2.7 Tag Installation

2.7.1 Inspected and Treated Poles

The tags used should meet the relevant specification (Appendix-R) and should be placed not less than 5' and not more than 7' above the ground line.

- Inspected Only – Attach a dated test tag at eye level on the roadside face of the pole.
- Inspected and Treated – The dated test tag is to be attached to the pole at eye level on the roadside face of the pole. If internal treatment was applied, the dated product tag will be installed at eye level on the roadside face of the pole.
- Stubbed Poles – The dated test tag is to be attached on the side of the stub facing the road. The date tag should be located immediately below the upper band. If steel stubs are installed, the date tag is to be located immediately above the stub face of the pole on the roadside.

2.7.2 Poles Requiring Additional Attention

Inspected poles which require additional attention or replacement must be marked with an Orange plastic tag stapled to the pole.

Poles posing immediate safety hazard will be tagged with a White replacement tag and poles will be changed in the same year as the test. The exact location and type of structure must be identified.

Call the District Team Lead and Construction Lead. The D.A.M. Supervisor is to be notified immediately. When evaluations are completed after normal working hours or on weekends, contact After Hours Assistance (1-800-667-1261) to advise the Region Supervisor On-call or the Edmonton Emergency Centre (780-423-4211).

2.8 Pole Inspection Report Form

The Pole Inspection Report form is the primary record of all test and treat activities and the basis for administering payment to contractors.

Specific instructions on completing each section of the form are provided . It is important that the abbreviations and codes provided there be used consistently for ease of budgeting.

- All inspection data, treatment and recommendations are to be included on the Pole Inspection Report form.
- All Pole Inspection Report form numbers are to correspond to numbers indicating the location (miles) on the master map.
- One clean master map to be provided with numbered miles corresponding to the Inspection Report page numbers.
- One master map for a combination of REA/AE/OF poles in a block.
- One master map for each town
- One master map for each '5L' distribution line in block
- Inspection routes and numbering are to be in an organized and easy to follow sequence.
- All Pole Inspection Report information are to indicate line ownership so that plant numbers can be charged with the appropriate capital charges. (To aid contract inspectors in identifying line ownership, a color-coded map with legend will be provided at the start-up meeting.)
- Inspectors are to indicate on a new, clean map all pole replacement locations noted on the Pole Inspection Report information
- All Pole Inspection Report information are to be sent electronically to the ATCO Electric region maintenance supervisor. ATCO Electric will be the sole owner of all records.

3.0 Invoicing

Contractor invoices must indicate the number of poles tested, recorded and/or treated according to each pole age block, and assign the cost to the correct budget, as per Table-A. Summary sheet indicating number of poles in each age group and tasks completed to accompany each invoice by Plant Number.

- One for REA
- One for Company Rural Poles
- One for Oilfield Poles
- One for Towns
- One for each '5L' distribution line

Table-A:

Poles	Activity	Budget
a. F.L.P.T. Poles aged 20 years or more with bandage & b. Butt-treated Poles	• Visual, sound, test (drill) and record (100%)	O&M
	• Internal treat(liquid)/boron	Capital
Poles aged 20 years or more without bandage	• Visual, sound, test (drill), Internal treat (liquid)/boron, bandage and record (100%)	Capital
Poles aged 10 to 19 years	• Visual and record (90%)	O&M
	• Visual, sound, test (Drill), Internal treat (liquid)/boron and record (10%)	Capital
Poles less than 10 years	• Visual, sound and record	O&M

3.1 Task Codes

A –Test (drill), Boron, Bandage, Record
I –Test (drill) and record
V –Visual, sound and record
B –Install boron rod
L –Internal treat (liquid)
F – Foam treatment & ant bait
N – Add identification tag

4.0 Test and Treat Requirements

Pole identification information is provided in Appendix A.

- **Sounding Poles with Cobra Wrap installed:**
  When sounding poles with Cobra Wrap installed, the pole should be sounded at ground level, every 6" apart to determine if any external and internal weaknesses can be detected, as part of the normal sounding process of the pole.
- **Retreating Poles with Cobra Wrap Installed:**
  When treating poles with Cobra Wrap installed, sound the pole at ground level to determine external and internal weaknesses and drill a hole at 60 degrees in the N, SE and SW quadrants above the wrap and install the appropriate amount of rods to correspond with the diameter of the poles. If an internal deterioration is detected, activate the rods with Timbor liquid.

- **Retreating Poles with Cobra Rods above ground level:**
  Sound the pole at ground level to determine external and internal weaknesses, remove one of the plugs from a quadrant and test with the shell depth indicator for internal deterioration. If any damage is detected, pull the two remaining plugs and check for internal deterioration. If no deterioration is found in the first hole, drill 2" above the existing plugs in the N, SE and SW quadrants at 60 degrees and install the appropriate number of rods to correspond with the diameter of the pole. If any internal deterioration is detected in the drilled holes, activate the newly installed rods with Timbor liquid.

Before starting excavation on any pole, check whether it needs to be tested (drilled). The following categories of poles **DO NOT** require testing (drilling):

- **Full Length Pressure Treated Poles (F.L.P.T), depending on age**
  Some of these poles may require visual, sound and recording only, as indicated in Table-A above. See sections 4.1 to 4.4 for details.

- **Broken Poles**
  These poles should be immediately condemned for stubbing or replacement.

- **Severely Decayed Poles**
  Poles so obviously decayed at the ground line or pole top that the minimum required circumference would not be met are usually condemned for stubbing or replacing.

  The procedures outlined below are based on the age of the poles, Procedures for stub and burned poles are given in section 4.5.

Refer to section 2.0 for details on testing, treatment application and tag installation.

4.1 F.L.P.T. Poles aged 20 years or more with bandage, butt-treated poles.

1. Refer section 4.0 above, for test & treat of poles with Cobra wraps and Cobra rods installed already.
2. Check visually, sound test, excavate, drill and assess the strength of each pole according to the instructions provided in sections 2.0 to 2.5. If the pole fails any test, stop testing and follow instruction step 4 given below.
3. If the pole passes all tests:
   - Install a test date tag and remove any previous test date tags.
   - Treat internally for hollow heart and/or insects using the approved treatment. Install a treatment date tag.
   - Install the appropriate number of rods to correspond with the diameter of the pole as per section 4.0, above.
4. Determine any further action required (i.e., stubbing,* guying, replacement) and tag the pole accordingly.
5. Record inspection data, treatment and recommended action (if any) on the Pole Inspection Report form.

6. If a pole installation date tag is not available, provide a suitable tag identifying the installation decade to simplify age identification in the next cycle.
7. Replace the excavated soil.

NOTE: Stubbing may not be economically justified in all areas.

NOTE: Do not excavate around poles with underground services attached unless supervised by a qualified utility employee.

***** NOTE: No excavations required around poles encased in cement or pavement. The test holes in this case will be drilled at 30° to the pole axis downward from ground level to a depth of 300mm-400mm (depending on the circumference of the pole) toward the center of the pole. Use the multiplying factor of 0.5 to obtain shell thickness.***

4.2 Poles aged 20 years or more without bandage:

1. Check visually, sound test, excavate, drill and assess the strength of each pole according to the instructions provided in sections 2.0 to 2.5. If the pole fails any test, stop testing and follow instruction step 9 given below.
2. If the pole passes all tests:
3. Install a test date tag and remove any previous test date tags.
4. Treat internally for hollow heart and/or insects using the approved treatment.
5. Install the appropriate number of rods to correspond with the diameter of the pole as per section 2.6.2.
6. Install the Cobra Wrap as per section 2.6.1.
7. Install a treatment date tag.
8. If a pole installation date tag is not available, provide a suitable tag identifying the installation decade to simplify age identification in the next cycle.
9. Determine any further action required (i.e., stubbing,* guying, replacement) and tag the pole accordingly.
10. Record inspection data, treatment and recommended action (if any) on the Pole Inspection Report form.
11. Replace the excavated soil.

4.3 F.L.P.T Poles aged 10 to 19 years:

On 10 percent of these poles (one pole every kilometer):

1. Conduct visual inspection and sound tests on all poles, and install test date tags. Test (drill) and treat internally for hollow heart and/or insects using the approved treatment. If the pole fails any test, stop testing and determine any further action required (i.e., stubbing,* guying, replacement) and tag the pole accordingly.
2. Install test and treatment date tags.
3. Record inspection and treatment data on the Pole Inspection Report Form

On the remaining 90% of poles,

1. Conduct visual inspection and sound tests on all poles, and install test date tags. No treatment is required unless data indicates (i.e., evidence of insects).
2. Record inspection and treatment data on the Pole Inspection Report Form.

4.4 F.L.P.T Poles aged less than 10 years:

1. Conduct visual inspection and sound tests on all poles, and install test date tags. No treatment is required unless data indicates (i.e., evidence of insects).
2. Record inspection and treatment data on the Pole Inspection Report Form.

4.5 Other Poles

4.5.1 Stub Poles

1. Conduct visual inspection and sound test.
2. Inspect the tightness of the metal bands:

a. If the bands are loose and there is indication of shell rot, the pole should be replaced.

b. If the bands are tight, drill near the metal banding area. (between bands)
   - If the pole passes the drill test, treat for Hollow Heart and/or insects, install test and treatment date tags and record all inspection and treatment data on the Pole Inspection Report form.
   - If the pole fails the drill test, this is an indication of sub-surface rot. Recommend replacement of the pole and stub on the Pole Inspection Report form.

c. Test stub if pole passes test.

4.5.2 Burned Poles

For poles that have been scarred by prairie or forest fire but still have adequate strength to remain in service, install a bandage at normal level (if burned at ground line) and apply an internal treatment to deter infestation of insects and ingress of fungus at ground line.

5.0 Storage, handling, transportation, application and disposal of preservatives.

The personnel concerned with storage, handling, transportation, application and disposal of wood preservatives shall comply with the requirements of the Alberta Environmental Protection and Enhancement Act and Regulations.

Based on the nature of preservative employed and regulations applicable, a certified applicator may be required to:

- Be in continuous attendance at the site while wood preservatives are being applied.
- Preferably have proof of relevant applicator certification at or near the treatment location, readily available for inspection.

- Supervise no more than four uncertified individuals at one time.
- Maintain continuous contact, auditory and/or visual, with the uncertified individuals.
- Be within 500 metres of persons being supervised.

General requirements:
Personnel engaged in wood preservative storage, handling, transportation, application and disposal must adhere to the following requirements when preparing to apply wood preservatives.

- Check the program schedule to ensure that the proposed treatment locations, the proposed treatment (including the preservative and its method of application), and the total number of wood poles to be treated are correct.
- Be aware of the boundaries of the proposed treatment area, the requirements for personal protection (including Material Safety Data Sheets), and the procedures required to protect human health and the environment.
- Carry out a site inspection at each pole to ensure that the applicable regulatory requirements and standards can be met in carrying out the use.
- Keep wood preservatives in their original containers and with original packaging and labeling affixed, or in appropriate containers with trade name, name of active ingredient, concentration of active ingredient, and pesticide registration number affixed.
- Ensure that domestic and agricultural water sources and soil used for agricultural crop production are protected. In addition, perform a field check to look for drinking water sources, and note any unregistered water intakes or wells.
- Ensure that application equipment is in good working order, and is properly cared for and stored.
- Hold a tail-board meeting or conference call to discuss the following:
  - intended work schedule
  - work plan for the site
  - types of wood preservatives being used
  - specific issues relating to the site, such as Farms or public
  - concerns
  - environment and safety issues
- Have current Material Safety Data Sheets and product labels for the products they are using, read and follow product labels, and keep a copy of this document available at all times.
- Complete Daily Operations Records, and closely follow all specifications.
- Report promptly any violation to AE's Construction Lead.

Storage requirements
Wood preservatives must be stored in a manner that minimizes hazards to human health and the environment. Personnel must adhere to the following legal requirements for all storage facilities for wood preservatives.

Storage instructions

- Store wood preservatives separately from food intended for human or animal consumption.
- Keep wood preservatives in storage facilities that are locked when unattended, accessible only to authorized persons.
- Keep facilities clean, well-marked, and ventilated to the outside.
- Mark storage facility in block letters "WARNING: CHEMICAL STORAGE – AUTHORIZED PERSONS ONLY" so signs are visible to persons approaching each door providing access to the facility.
- Keep storage facilities separate from work and living areas, flammable materials, and bodies of water.
- Store fumigants and other wood preservatives that release vapours or those which display a poison symbol on the label in a storage facility that is not attached to or within a building used for living accommodations.
- Mixing procedures do not apply to wood preservatives, as all products are pre-mixed by the manufacturer and are purchased ready to use.
- Loading involves applying pre-mixed grease to site-made bandages.
- Personnel must handle, load, apply, or dispose of preservatives and containers in a manner that minimizes hazards to human health and the environment.
- Personnel must adhere to the following legal requirements for the handling of wood preservatives, as per the Alberta Regulations.
- Do not wash or submerge in a body of water any container used to prepare, mix, or apply preservatives.
- Ensure that adequate water for washing, first aid equipment, spill kits, and emergency phone numbers are close at hand.
- Decant liquid preservatives and make bandages at least 15 metres from any body of water, and in a location that will minimize the potential for spills entering a body of water (e.g., on flat terrain with a non-porous substrate).
- Keep containers well below eye level to prevent splashing or spilling preservatives in the face or eyes.
- Report promptly any violation to AE's Construction Lead.

Transportation requirements

Personnel must adhere to the following legal requirements for the transportation of wood preservatives.

Ensure that the wood preservative is properly secured during transport to prevent accidental discharge or unauthorized removal, and to prevent contamination of food or drink intended for animal or human consumption, household furnishings, toiletries, clothing, bedding, or similar items transported with the wood preservative.

In addition, the personnel involved in transportation of preservatives need to:

- Be familiar with the product label and Material Safety Data Sheet outlining the transportation requirements for each regulated product used as wood preservative.

- Keep in the vehicle a first aid kit, fire extinguisher, spill response contingency plan, and spill contingency kit. Vehicle operators must be trained to handle spills.
- Inspect containers for defects prior to transport. Transfer any defective packages to empty pesticide containers of the same type, or secure any defective containers into secondary containment vessels for transportation.

Application requirements

In general, personnel who will be applying wood preservatives will adhere to the following requirements.

- Do not apply preservatives if water fills the excavation during belowground treatments.
- Do not apply any wood preservatives within a no-treatment zone.
- Do not treat more than the number of wood poles specified on the Program schedule.
- Report promptly any violation to AE's Construction Lead.

Disposal requirements

The disposal of preservatives and their containers shall be as per the guidelines given in Alberta User Guide for Waste Managers. In general,

- Rinse the empty containers according to the following table.
- Dispose of empty containers at an approved sanitary landfill or send them back to the manufacturer for appropriate disposal.

#	Type of container	Rinse method
1	Rigid plastic or metal (non-pressurized)	Pressure rinse, or rinse 3 times
2	Glass bottle	Rinse 3 times
3	Plastic bag	Rinse
4	Paper bag	Rinse

Handling Spillage

Personnel must comply with the following requirements:

- Ensure that an appropriate spill containment kit and a spill contingency plan are at the application site.
- Ensure the safety of workers and public by limiting access to the spill area, protecting people from exposure, and ensuring wash facilities are nearby.
- Put on protective equipment before cleaning up the spill, including protective clothing, respirators, and eye protection as required.
- Contain the spill.
- Report promptly any spillage to AE's Construction Lead.
- Clean up the site.

Part 3 - Pole Replacement and Stubbing

1.0 Miscellaneous Pole Replacement

These include any rotten (shell/hollow heart) undersized (pole circumference) fire/machine/lightning/storm damaged or clearance deficient pole in general identified by field staff. These are to be replaced under the blanket project assigned to each Region.)MWR must be completed and sent to D.A.M. Supervisor for that region for approval prior to work being undertaken.

2.0 Danger Pole/ White tag pole

Danger poles are those not meeting specifications and determined by formal test to be of sufficient critical condition to have to be changed in the same year as the formal test. Poles in critical condition and posing safety hazard are to be immediately attended by guying, bracing, or replacement. In general, two poles per Plant Number can be changed using the emergency/danger project number set up for each Region. Use Regional danger pole project number to track the change. A field check form and map will need to be completed to activate the change. A separate project number per plant would be required for a large quantity of poles to be replaced.

3.0 Pole Replacement/Stubbing/ Orange tag pole

All necessary documentation must be prepared in advance (i.e., field check, maps etc.). Complete, in-depth documents and maps will provide the main information for the tendering package. Pole replacement process shall include the following steps.

3.1 Obtain approval from REAs to proceed with work.

3.2 Obtain appropriate Project number from the D.A.M. Clerk.

3.3 Pole replacement tags will be marked with sequential numbers that match those on the staking list to avoid congestion on busy non-urban maps.

3.4 Follow the selected route. Document pole replacements taking care of re-spanning requirements, , re-conductoring if feasible; structure height increases or rerouting. The documentation should also include the physical conditions of the site (e.g., swamps, crops and farm field operations) and replacement timing. Arrange manpower to complete a formal field check, using design criteria summary produced by the Technical Services Group to aid the field checker in determining pole selection to match conditions found in the field. Document all replacements on maps and pertinent information on the Pole Change Field Check Form). The field check should also determine the most economical and feasible route to aid the replacement crews. Field checks can be done by a Journeyman or Lineman survey.

3.5 Completed Field check is returned to D.A.M. Supervisor to ensure field check notes, tool kit jacket, scope document and requisition are complete. Package is then forwarded to Technical Services to review, estimate, and approve. D.A.M. Program Supervisor is to negotiate necessary due dates with Project Leads and document electronically in Project Planning Database.

3.6 When Project package is returned from Engineering, forward to D.A.M. Supervisor for approval.

3.7 When Project package is approved, D.A.M. Supervisor to release to the Project Lead for construction scheduling.

3.8 Construction Supervisor then assigns a Construction Lead and contracts for work either internally or externally by cost plus unit or tendering.

3.9 Construction Lead and/or assigned crew design a work plan to carry out the project. When project is complete, the crew foreman completes a commissioning report and sends it to the Construction Supervisor.

3.10 Construction Lead or Supervisor completes a quality check and documents findings as per Appendix D; Construction Inspection Report.

3.11 Five percent of replaced poles are to be cut and photographed for quality control in order to provide program justification and to aid research and development.

3.12 Disposal of all poles changed will follow the Materials Management Process for NCV material disposal. A Release and Indemnity Agreement will be completed and filed for selling or donating all treated wood products deemed NCV.

3.13 Construction Lead reconciles WO as per WO Process and returns to Tech Services.

3.14 Project Lead informs D.A.M Supervisor of all applicable dates.

3.15 Transformers on poles being changed during replacement will be re-installed where they are not overloaded. Replace the ones that have oversized breakers or are in a location where we expect they have seen a lot of overload. Small parallel transformers shall be replaced with a single unit. In any case, the replaced equipment shall be charged to the blanket transformer equipment work order.

3.16 It is important to handle the transformer/equipment gently when removing and reinstalling them at the same location.

3.17 Orange tagged poles are to be targeted for replacement at the end of the second calendar year from year of test. Any pole change projects that cannot be completed within these time frames will require the approval of the Distribution Asset Management group, who will conduct a further review and analysis, and may require some of the poles to be white-tagged for immediate replacement while allowing others to be deferred.

4.0 Woodpecker hole repair

Woodpeckers and their nests are protected under the Migratory Birds Convention Act. Please refer to Appendix-Q for repair of woodpecker holes.

After repair, two brightly colored plastic streamers (reflector type bird repeller ribbon) of lengths 3 feet each to be stapled/duct taped to the pole opposite to each other (i.e. @ 180◦) at an elevation where the woodpecker activity has been noticed. This is to deter woodpeckers away from the pole.

Poles treated for woodpecker hole need to be recorded for future follow-up visits at random.

5.0 Treatment and control of ants

Ants (mostly, carpenter ants or wood ants) cause extensive damage to poles by carving wood within a short span of time. These ants are more active during nights but could be spotted anytime. In severe infestations, there could be about ten satellite colonies connected to the main colony by trails and located as far as 300 feet. Ant infestations could be identified by wood shavings, soil, dead ants and insect parts. A carpenter ant attack on wood is distinguished from termite damages by the smooth and clean carvings usually across the grain and by the absence of mud in the carvings.

If the pole has been already affected by ants, then both the infected and nearby uninfected portions of the pole are to be directly sprayed with Bora-care or equivalent and then to be followed up with foaming.

Foaming is used to achieve better penetration of the affected pole areas. The process involves injection of Bora-care and foaming agent like Termitafoam by means of a suitable applicator.

Ant baits are effective means of ant control. They work by decreasing the ants' population in an area and thereby reducing their potential to damage the poles. Apply Niban FG fine granular bait or equivalent in an annular band of width about 30 cm and about 5cm depth below groundline about 60cm away from the pole (see fig 1, below). This bait is reasonably weather-resistant and will be effective in reducing the number of ants in the surrounding colonies.

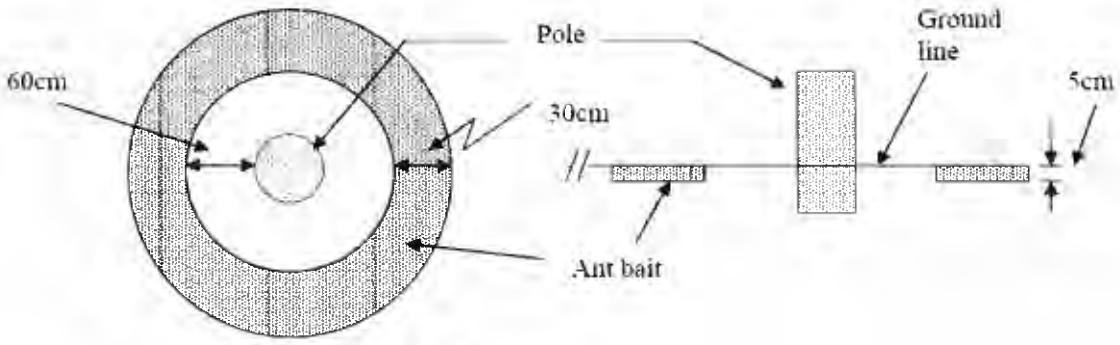


Fig-1

Note: Necessary care to be taken **not to** mix or contaminate the bait with spray/foam. Use separate containers, cups, dusters etc. to avoid contamination. ***Even traces of pesticide/foam could render the bait ineffective.***

Poles treated for ants are to be recorded. These poles shall be revisited at random for follow-up of the treatment employed.

ID	Account Number	Group Number	Company Number	Transaction Year	Installation Year	Transaction Code	Amount	Adjusted TY	Comments	HasEdits	ParentID
1	42000			1994	1955	0	-12,000.00	0		FALSE	0
2	42000			2011	1987	8	767,223.86	0		FALSE	0
3	42000			2011	1989	8	106,282.56	0		FALSE	0
4	42000			2011	1990	8	1,347.72	0		FALSE	0
5	42000			2011	1991	8	12,675.08	0		FALSE	0
6	42000			2011	1992	8	15,093.64	0		FALSE	0
7	42000			2001	1993	3	-19,084.20	1993		FALSE	0
8	42000			2011	1993	8	152,203.08	0		FALSE	0
9	42000			2001	1994	3	-3,657.90	1994		FALSE	0
10	42000			1997	1996	3	-53,558.80	1996		FALSE	0
11	42000			2001	1996	4	3,500.40	1996		FALSE	0
12	42000			2011	1996	8	24,178.48	0		FALSE	0
13	42000			2001	1997	3	-186.40	1997		FALSE	0
14	42000			2011	1997	8	36,567.29	0		FALSE	0
15	42000			2001	1998	3	-47,260.40	1998		FALSE	0
16	42000			2001	1999	3	-5,411.40	1999		FALSE	0
17	42000			2002	2000	3	6,999.80	2000		FALSE	0
18	42000			2011	2000	8	113,629.19	0		FALSE	0
19	42000			2011	2001	8	20,729.69	0		FALSE	0
20	42000			2011	2002	8	11,519.73	0		FALSE	0
21	42000			2011	2003	8	2,788.31	0		FALSE	0
22	42000			2011	2004	8	42,198.95	0		FALSE	0
23	42000			2011	2005	8	111,863.49	0		FALSE	0
24	42000			2009	2007	4	98,112.46	0		FALSE	0
25	42000			2011	2007	8	98,112.46	0		FALSE	0
26	42000			2009	2008	4	3,594.79	0		FALSE	0
27	42000			2011	2008	8	361,040.89	0		FALSE	0
28	42000			2010	2009	4	657.80	0		FALSE	0
29	42000			2011	2009	4	2,769.59	2009		FALSE	0
30	42000			2011	2009	8	165,479.56	0		FALSE	0
31	42000			2011	2010	4	1,271,471.71	2010		FALSE	0
32	42000			2011	2010	8	1,271,471.71	0		FALSE	0
33	42000			2011	2011	8	408,237.27	0		FALSE	0
34	44200			1978	1958	0	-100.00	0		FALSE	0
35	44200			1986	1959	0	-6.00	0		FALSE	0
36	44200			1971	1966	0	-5,674.00	0		FALSE	0
37	44200			2011	1971	8	163,957.92	0		FALSE	0
38	44200			2011	1974	8	8,707.10	0		FALSE	0
39	44200			2011	1976	8	15,576.34	0		FALSE	0
40	44200			2011	1977	0	-170.40	0		FALSE	0
41	44200			2011	1978	8	170.40	0		FALSE	0
42	44200			2003	1980	0	-10,000.00	0		FALSE	0
43	44200			2011	1982	8	55,338.07	0		FALSE	0
44	44200			2011	1983	8	42,062.15	0		FALSE	0
45	44200			2004	1985	0	-2,028.00	0		FALSE	0
46	44200			2011	1985	8	13,952.01	0		FALSE	0
47	44200			2011	1986	8	22,121.90	0		FALSE	0
48	44200			2011	1987	8	311,360.32	0		FALSE	0
49	44200			2011	1988	8	39,385.22	0		FALSE	0
50	44200			2011	1989	8	29,819.59	0		FALSE	0
51	44200			2011	1991	8	1,409.87	0		FALSE	0
52	44200			2011	1992	8	10,141.91	0		FALSE	0

53	44200	2011	1993	8	59,158.97	0	FALSE	0
54	44200	2011	1996	8	8,908.07	0	FALSE	0
55	44200	1997	1997	4	20,338.09	1997	FALSE	0
56	44200	2001	1997	4	186.47	1997	FALSE	0
57	44200	2011	1997	8	53,204.86	0	FALSE	0
58	44200	2011	1998	8	54,144.48	0	FALSE	0
59	44200	2011	1999	8	29,783.20	0	FALSE	0
60	44200	2011	2001	8	186.47	0	FALSE	0
61	44200	2011	2004	8	1,001.91	0	FALSE	0
62	44200	2011	2005	8	243,013.04	0	FALSE	0
63	44200	2011	2006	8	221,326.80	0	FALSE	0
64	44200	2008	2007	4	2,926.15	2007	FALSE	0
65	44200	2009	2007	4	61,929.53	0	FALSE	0
66	44200	2011	2007	8	181,455.77	0	FALSE	0
67	44200	2009	2008	4	238,386.55	0	FALSE	0
68	44200	2011	2008	8	322,680.35	0	FALSE	0
69	44200	2010	2009	4	30.85	0	FALSE	0
70	44200	2011	2009	4	274.76	2009	FALSE	0
71	44200	2011	2009	8	25,330.54	0	FALSE	0
72	44200	2011	2011	8	28,306.73	0	FALSE	0
73	44400	1959	1957	0	-7,910.00	0	FALSE	0
74	44400	1961	1957	0	-1,700.00	0	FALSE	0
75	44400	1966	1960	0	-349.00	0	FALSE	0
76	44400	1997	1960	0	-120.00	0	FALSE	0
77	44400	1987	1963	0	-1,986.00	0	FALSE	0
78	44400	1988	1963	0	-1,203.00	0	FALSE	0
79	44400	1987	1968	0	-1,640.00	0	FALSE	0
80	44400	1983	1969	0	-2.00	0	FALSE	0
81	44400	2011	1971	0	-9,402.20	0	FALSE	0
82	44400	2011	1971	8	3,005.24	0	FALSE	0
83	44400	1978	1973	0	-8.00	0	FALSE	0
84	44400	1998	1973	0	-8,509.00	0	FALSE	0
85	44400	2007	1973	0	-1,425.70	0	FALSE	0
86	44400	2011	1973	0	-7,891.80	0	FALSE	0
87	44400	2011	1973	8	5,061.79	0	FALSE	0
88	44400	2011	1976	8	8,400.29	0	FALSE	0
89	44400	1998	1978	0	-1,491.00	0	FALSE	0
90	44400	2007	1978	0	-1,774.00	0	FALSE	0
91	44400	2011	1978	0	-228.00	0	FALSE	0
92	44400	2011	1978	8	989.00	0	FALSE	0
93	44400	2003	1980	0	-10,000.00	0	FALSE	0
94	44400	1992	1982	0	-301.60	0	FALSE	0
95	44400	2011	1982	8	52,075.44	0	FALSE	0
96	44400	2011	1985	0	-6,229.50	0	FALSE	0
97	44400	2011	1985	8	1.00	0	FALSE	0
98	44400	2011	1986	8	7,089.08	0	FALSE	0
99	44400	2004	1987	0	-9,322.00	0	FALSE	0
100	44400	2011	1987	8	20,835.31	0	FALSE	0
101	44400	2011	1988	8	86,979.73	0	FALSE	0
102	44400	2011	1989	8	9,936.21	0	FALSE	0
103	44400	2011	1990	8	14,133.96	0	FALSE	0
104	44400	2011	1993	8	126,332.65	0	FALSE	0
105	44400	2011	1994	8	92,190.19	0	FALSE	0

106	44400	2011	1996	8	5,470.27	0		FALSE	0
107	44400	2011	1997	8	397,144.70	0		FALSE	0
108	44400	2011	1998	8	212,029.62	0		FALSE	0
109	44400	2001	1999	4	0.71	1999		FALSE	0
110	44400	2011	1999	8	146,101.74	0		FALSE	0
111	44400	2011	2003	8	74,195.05	0		FALSE	0
112	44400	2011	2004	8	40,176.97	0		FALSE	0
113	44400	2011	2005	8	685,038.50	0		FALSE	0
114	44400	2011	2006	8	100,239.51	0		FALSE	0
115	44400	2011	2007	8	25,562.13	0		FALSE	0
116	44400	2011	2008	8	27,179.87	0		FALSE	0
117	44400	2010	2009	4	364.82	0		FALSE	0
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121	44500	1991	1955	0	-10,970.00	0		FALSE	0
122	44500	1990	1956	0	-13,164.00	0		FALSE	0
123	44500	1984	1957	0	-18,800.00	0	Corrected Transaction year	TRUE	0
124	44500	1961	1957	0	-1,613.00	0		FALSE	0
125	44500	1969	1957	0	-1,432.00	0		FALSE	0
126	44500	1972	1957	0	-2,550.00	0		FALSE	0
127	44500	1990	1957	0	-8,600.40	0		FALSE	0
128	44500	1970	1959	0	-19,433.00	0		FALSE	0
129	44500	1973	1959	0	-19,433.00	0		FALSE	0
130	44500	1961	1960	0	-2,695.00	0		FALSE	0
131	44500	1980	1960	0	-10,000.00	0	Corrected Transaction year	TRUE	0
132	44500	1963	1960	0	-2,013.00	0		FALSE	0
133	44500	1966	1960	0	-581.00	0		FALSE	0
134	44500	1989	1960	0	-2,272.00	0		FALSE	0
135	44500	1989	1961	0	-14,259.00	0		FALSE	0
136	44500	1973	1962	0	-6,718.00	0		FALSE	0
137	44500	1985	1962	0	-3,937.30	0		FALSE	0
138	44500	1988	1962	0	-6,364.00	0		FALSE	0
139	44500	1989	1962	0	-17,370.00	0		FALSE	0
140	44500	1991	1962	0	-2,772.10	0		FALSE	0
141	44500	1967	1963	0	-17,371.00	0		FALSE	0
142	44500	1970	1963	0	-1,193.00	0		FALSE	0
143	44500	1975	1963	0	-630.00	0		FALSE	0
144	44500	1983	1963	0	-10,422.00	0		FALSE	0
145	44500	1986	1963	0	-30,762.20	0		FALSE	0
146	44500	1987	1963	0	-8,299.00	0		FALSE	0
147	44500	1988	1963	0	-10,119.00	0		FALSE	0
148	44500	1967	1964	0	-6,969.00	0		FALSE	0
149	44500	1967	1964	0	-24,838.00	0		FALSE	0
150	44500	1985	1964	0	-34,302.90	0		FALSE	0
151	44500	1991	1965	0	-387.90	0		FALSE	0
152	44500	1967	1966	0	-1,776.00	0		FALSE	0
153	44500	1973	1966	0	-7,375.00	0		FALSE	0
154	44500	1986	1966	0	-7,502.10	0		FALSE	0
155	44500	1989	1966	0	-14,902.00	0		FALSE	0
156	44500	1997	1966	0	-27,883.90	0		FALSE	0
157	44500	1969	1967	0	-5,226.00	0	Corrected Transaction year	TRUE	0
158	44500	1992	1967	0	-62,822.00	0	Corrected Transaction year	TRUE	0

159	44500	1970	1967	0	-1,113.00	0		FALSE	0
160	44500	1972	1967	0	-3,586.00	0		FALSE	0
161	44500	1972	1967	0	-4,645.00	0		FALSE	0
162	44500	1973	1967	0	-2,005.00	0		FALSE	0
163	44500	1974	1967	0	-2,005.00	0		FALSE	0
164	44500	1985	1967	0	-1,995.70	0		FALSE	0
165	44500	1991	1967	0	-100,003.00	0		FALSE	0
166	44500	1996	1968	0	-108,433.00	0	Corrected Transaction year	TRUE	0
167	44500	1969	1968	0	-809.00	0		FALSE	0
168	44500	1983	1968	0	-129.00	0		FALSE	0
169	44500	1984	1968	0	-20.00	0		FALSE	0
170	44500	2011	1970	4	11,318.70	1970		FALSE	0
171	44500	2011	1971	3	-73,842.60	1971		FALSE	0
172	44500	1978	1972	0	-2,267.00	0		FALSE	0
173	44500	1984	1972	0	-25,020.00	0		FALSE	0
174	44500	1985	1972	0	-3,256.00	0		FALSE	0
175	44500	2011	1972	0	-15,938.60	0		FALSE	0
176	44500	2011	1972	3	-839.50	1972		FALSE	0
177	44500	2011	1972	8	2,226.84	0		FALSE	0
178	44500	1990	1973	0	-297.80	0		FALSE	0
179	44500	1991	1973	0	-27,045.00	0		FALSE	0
180	44500	1998	1973	0	-20,000.00	0		FALSE	0
181	44500	2011	1973	0	-19,855.50	0		FALSE	0
182	44500	2011	1973	3	-6,420.80	1973		FALSE	0
183	44500	2011	1973	8	11,370.97	0		FALSE	0
184	44500	1976	1974	0	-5,500.00	0		FALSE	0
185	44500	1985	1974	0	-72,929.80	0		FALSE	0
186	44500	1985	1974	3	-6,457.30	1974		FALSE	0
187	44500	1991	1974	0	-26,682.00	0		FALSE	0
188	44500	2011	1974	0	-1,346.10	0		FALSE	0
189	44500	2011	1974	3	-27,872.50	1974		FALSE	0
190	44500	2011	1974	3	-3,539.80	1974		FALSE	0
191	44500	2011	1974	8	10,228.27	0	3539.81 adjustment to correct credit balance	FALSE	0
192	44500	2011	1975	0	-3,760.60	0		FALSE	0
193	44500	2011	1975	8	0.00	0	3539.81 adjustment to correct credit balance	FALSE	0
194	44500	1999	1976	0	-145,438.00	0		FALSE	0
195	44500	2011	1976	3	-27,045.00	1976		FALSE	0
196	44500	2011	1976	8	0.00	0		FALSE	0
197	44500	2011	1977	0	-19,460.80	0		FALSE	0
198	44500	2011	1977	3	-6,073.10	1977		FALSE	0
199	44500	2011	1977	8	13,449.59	0		FALSE	0
200	44500	1979	1978	0	-1,504.00	0		FALSE	0
201	44500	1992	1978	0	-2,560.00	0		FALSE	0
202	44500	1993	1978	0	-2,200.00	0		FALSE	0
203	44500	1998	1978	0	-32,500.00	0		FALSE	0
204	44500	1999	1978	0	-141,383.00	0		FALSE	0
205	44500	2011	1978	0	-15,356.40	0		FALSE	0
206	44500	2011	1978	8	2,815.04	0		FALSE	0
207	44500	1999	1981	0	-38,966.30	0		FALSE	0
208	44500	2011	1981	0	-29,667.70	0		FALSE	0
209	44500	2011	1981	3	-32,617.20	1981		FALSE	0
210	44500	2011	1981	8	9,768.58	0		FALSE	0
211	44500	2011	1982	3	-37,352.50	1982		FALSE	0

212	44500	1989	1983	0	-36,362.00	0		FALSE	0
213	44500	1997	1983	0	-62,899.50	0		FALSE	0
214	44500	2011	1983	0	-20,431.80	0		FALSE	0
215	44500	2011	1983	4	31,559.61	1983		FALSE	0
216	44500	2011	1983	8	38,289.51	0		FALSE	0
217	44500	2011	1984	0	-65,205.70	0		FALSE	0
218	44500	2011	1984	3	-58,533.60	1984		FALSE	0
219	44500	2011	1984	8	6,948.18	0		FALSE	0
220	44500	1989	1985	0	-26,447.00	0		FALSE	0
221	44500	2011	1985	0	-144,856.00	0		FALSE	0
222	44500	2011	1985	4	599,823.40	1985		FALSE	0
223	44500	2011	1985	8	627,455.45	0		FALSE	0
224	44500	1987	1986	3	-1,162.00	1986		FALSE	0
225	44500	2011	1986	0	-51,819.80	0		FALSE	0
226	44500	2011	1986	4	47,795.60	1986		FALSE	0
227	44500	2011	1986	8	54,554.61	0		FALSE	0
228	44500	2011	1987	0	-7,375.00	0		FALSE	0
229	44500	2011	1987	3	-472,845.20	1987		FALSE	0
230	44500	2011	1987	8	70,155.25	0		FALSE	0
231	44500	2011	1988	0	-72,928.00	0		FALSE	0
232	44500	2011	1988	4	33,642.31	1988		FALSE	0
233	44500	2011	1988	8	68,773.17	0		FALSE	0
234	44500	2011	1989	0	-224,816.20	0		FALSE	0
235	44500	2011	1989	4	19,051.30	1989		FALSE	0
236	44500	2011	1989	8	246,298.62	0		FALSE	0
237	44500	1997	1990	0	-2,107.60	0		FALSE	0
238	44500	2011	1990	0	-80,042.40	0		FALSE	0
239	44500	2011	1990	4	71,679.87	1990		FALSE	0
240	44500	2011	1990	8	155,349.50	0		FALSE	0
241	44500	2011	1991	0	-323,968.00	0		FALSE	0
242	44500	2011	1991	4	29,179.86	1991		FALSE	0
243	44500	2011	1991	8	1,236,559.37	0		FALSE	0
244	44500	1993	1992	3	-729.60	0		FALSE	0
245	44500	2011	1992	0	-15,108.60	0		FALSE	0
246	44500	2011	1992	3	-97,492.00	1992		FALSE	0
247	44500	2011	1992	8	115,927.75	0		FALSE	0
248	44500	2011	1993	0	-52,219.40	0		FALSE	0
249	44500	2011	1993	8	1,102,745.73	0		FALSE	0
250	44500	2011	1994	0	-15,350.80	0		FALSE	0
251	44500	2011	1994	4	25,643.11	1994		FALSE	0
252	44500	2011	1994	8	192,607.71	0		FALSE	0
253	44500	1997	1996	4	2,107.57	1996		FALSE	0
254	44500	2001	1996	3	-3,500.40	1996		FALSE	0
255	44500	2011	1996	4	2,902.37	1996		FALSE	0
256	44500	2011	1996	8	307,541.93	0		FALSE	0
257	44500	2011	1985	0	-194,859.50	0	Corrected Transaction year	TRUE	0
258	44500	2011	1997	3	-31,559.60	1997		FALSE	0
259	44500	2011	1997	8	114,594.28	0		FALSE	0
260	44500	2004	1985	0	-47,038.00	0	Corrected Transaction year	TRUE	0
261	44500	2011	1988	0	-228,732.50	0	Corrected Transaction year	TRUE	0
262	44500	2011	1998	4	40,303.14	1998		FALSE	0
263	44500	2011	1998	8	404,901.30	0		FALSE	0
264	44500	2011	1999	0	-61,101.50	0		FALSE	0

265	44500	2011	1999	3	-36,802.70	1999		FALSE	0
266	44500	2011	1999	8	631,591.85	0		FALSE	0
267	44500	2011	2000	8	33,218.56	0		FALSE	0
268	44500	2011	2002	8	6,723.20	0		FALSE	0
269	44500	2011	2003	0	-28,717.40	0		FALSE	0
270	44500	2011	2003	4	4,164.42	2003		FALSE	0
271	44500	2011	2003	8	147,610.66	0		FALSE	0
272	44500	2011	2004	0	-19,953.10	0		FALSE	0
273	44500	2011	2004	3	-4,164.40	2004		FALSE	0
274	44500	2011	2004	8	804,795.07	0		FALSE	0
275	44500	2010	2009	4	23,668.11	0		FALSE	0
276	44500	2011	2009	4	3,165.49	2009		FALSE	0
277	44500	2011	2009	8	58,488.49	0		FALSE	0
278	44500	2011	2010	4	84,523.79	2010		FALSE	0
279	44500	2011	2010	8	181,335.10	0		FALSE	0
280	44500	2011	2011	8	536,447.29	0		FALSE	0
281	44600	1960	1957	0	-7,460.00	0		FALSE	0
282	44600	1990	1958	0	-2,134.30	0		FALSE	0
283	44600	1961	1960	0	-260.00	0		FALSE	0
284	44600	1965	1960	0	-789.00	0		FALSE	0
285	44600	1966	1960	0	-1,766.00	0		FALSE	0
286	44600	1989	1960	0	-8,726.00	0		FALSE	0
287	44600	1968	1963	0	-2,070.00	0		FALSE	0
288	44600	1970	1963	0	-240.00	0		FALSE	0
289	44600	1985	1963	0	-72.00	0		FALSE	0
290	44600	1989	1963	0	-2,615.00	0		FALSE	0
291	44600	1989	1964	0	-1,654.00	0		FALSE	0
292	44600	1969	1967	0	-35.00	0		FALSE	0
293	44600	1969	1967	0	-17,205.00	0		FALSE	0
294	44600	1970	1967	0	-8.00	0		FALSE	0
295	44600	1972	1967	0	-1,110.00	0		FALSE	0
296	44600	1973	1967	0	-393.00	0		FALSE	0
297	44600	2011	1971	0	-21,142.30	0		FALSE	0
298	44600	2011	1971	8	77,773.34	0		FALSE	0
299	44600	2011	1972	0	-1,850.00	0		FALSE	0
300	44600	2011	1972	8	17,103.07	0		FALSE	0
301	44600	1985	1973	4	6,457.34	1973		FALSE	0
302	44600	2011	1973	0	-4,462.10	0		FALSE	0
303	44600	2011	1973	8	14,978.26	0		FALSE	0
304	44600	2011	1974	0	-2,615.10	0		FALSE	0
305	44600	2011	1974	8	5,780.31	0		FALSE	0
306	44600	2011	1975	0	-103.50	0		FALSE	0
307	44600	2011	1975	8	0.00	0		FALSE	0
308	44600	2011	1976	0	-2,274.10	0		FALSE	0
309	44600	2011	1976	8	3,460.07	0		FALSE	0
310	44600	2011	1977	0	-2,453.80	0		FALSE	0
311	44600	2011	1977	8	161.28	0		FALSE	0
312	44600	2011	1980	0	-3,583.50	0		FALSE	0
313	44600	2011	1980	8	3,849.70	0		FALSE	0
314	44600	2011	1981	0	-417.00	0		FALSE	0
315	44600	2011	1981	8	4,382.96	0		FALSE	0
316	44600	2011	1982	0	-600.00	0		FALSE	0
317	44600	2011	1982	8	26,720.48	0		FALSE	0

318	44600	2011	1983	0	-1,069.40	0	FALSE	0
319	44600	2011	1983	8	3,521.61	0	FALSE	0
320	44600	2011	1984	8	9,095.34	0	FALSE	0
321	44600	1990	1985	0	-712.00	0	FALSE	0
322	44600	2011	1985	0	-6,617.30	0	FALSE	0
323	44600	2011	1985	8	1,408.73	0	FALSE	0
324	44600	2011	1986	0	-8,057.70	0	FALSE	0
325	44600	2011	1986	8	28,730.57	0	FALSE	0
326	44600	2011	1987	8	220,208.40	0	FALSE	0
327	44600	2011	1988	0	-4,746.20	0	FALSE	0
328	44600	2011	1988	8	0.00	0	FALSE	0
329	44600	2011	1989	0	-12,122.00	0	FALSE	0
330	44600	2011	1989	8	100,058.64	0	FALSE	0
331	44600	2011	1990	0	-107,410.10	0	FALSE	0
332	44600	2011	1990	8	121,839.18	0	FALSE	0
333	44600	2011	1991	0	-6,347.40	0	FALSE	0
334	44600	2011	1991	8	14,955.00	0	FALSE	0
335	44600	2011	1992	0	-809.00	0	FALSE	0
336	44600	2011	1992	3	-81.20	1992	FALSE	0
337	44600	2011	1992	8	27,196.00	0	FALSE	0
338	44600	1994	1993	4	144.34	1993	FALSE	0
339	44600	2001	1993	3	-17,452.50	1993	FALSE	0
340	44600	2011	1993	0	-1,500.10	0	FALSE	0
341	44600	2011	1993	8	88,937.87	0	FALSE	0
342	44600	2011	1994	8	9,356.98	0	FALSE	0
343	44600	2011	1997	8	219,877.38	0	FALSE	0
344	44600	2001	1998	4	47,260.48	1998	FALSE	0
345	44600	2011	1998	8	120,839.55	0	FALSE	0
346	44600	2001	1999	4	5,411.47	1999	FALSE	0
347	44600	2011	1999	8	163,692.44	0	FALSE	0
348	44600	2001	2000	0	-15,000.00	0	FALSE	0
349	44600	2011	2000	8	178,760.24	0	FALSE	0
350	44600	2011	2001	8	187,978.07	0	FALSE	0
351	44600	2011	2002	8	30,735.63	0	FALSE	0
352	44600	2011	2003	8	129,841.31	0	FALSE	0
353	44600	2011	2004	8	38,327.34	0	FALSE	0
354	44600	2011	2005	8	4,960.69	0	FALSE	0
355	44600	2011	2006	8	28,872.72	0	FALSE	0
356	44600	2008	2007	3	-357.50	2007	FALSE	0
357	44600	2011	2007	8	69,798.76	0	FALSE	0
358	44600	2009	2008	4	48,819.98	0	FALSE	0
359	44600	2010	2008	4	4,852.61	0	FALSE	0
360	44600	2011	2008	8	195,779.65	0	FALSE	0
361	44600	2011	2009	8	8,766.27	0	FALSE	0
362	44600	2011	2010	4	3,712.47	2010	FALSE	0
363	44600	2011	2010	8	3,712.47	0	FALSE	0
364	44600	2011	2011	8	52,856.96	0	FALSE	0
365	44700	1959	1957	0	-2,205.00	0	FALSE	0
366	44700	1963	1957	0	-1,000.00	0	FALSE	0
367	44700	1985	1963	0	-64.00	0	FALSE	0
368	44700	2011	1971	0	-14,213.00	0	FALSE	0
369	44700	2011	1971	8	3,380.71	0	FALSE	0
370	44700	2011	1979	8	4,179.21	0	FALSE	0

371	44700	1992	1982	0	-1,327.00	0	FALSE	0
372	44700	2011	1982	8	22,303.41	0	FALSE	0
373	44700	2011	1987	8	14,434.04	0	FALSE	0
374	44700	2011	1991	8	34,034.46	0	FALSE	0
375	44700	2011	1992	8	92,241.67	0	FALSE	0
376	44700	2011	1993	8	198.09	0	FALSE	0
377	44700	2011	1996	8	76.70	0	FALSE	0
378	44700	2011	1997	8	54,613.60	0	FALSE	0
379	44700	2011	1998	8	27,448.30	0	FALSE	0
380	44700	2011	1999	8	8,046.80	0	FALSE	0
381	44700	2011	2000	8	1,450.00	0	FALSE	0
382	44700	2011	2003	8	37,097.53	0	FALSE	0
383	44700	2011	2004	8	61,572.40	0	FALSE	0
384	44700	2011	2005	8	18,356.25	0	FALSE	0
385	44700	2011	2006	8	27,067.90	0	FALSE	0
386	44700	2008	2007	4	36,039.21	2007	FALSE	0
387	44700	2011	2007	8	258,491.11	0	FALSE	0
388	44700	2009	2008	3	-3,364.90	0	FALSE	0
389	44700	2011	2008	8	26,941.49	0	FALSE	0
390	44700	2011	2009	8	53,480.83	0	FALSE	0
391	44700	2011	2010	4	3,578.86	2010	FALSE	0
392	44700	2011	2010	8	8,942.89	0	FALSE	0
393	44700	2011	2011	8	91,716.59	0	FALSE	0
394	45700	1959	1948	0	-5,610.00	0	FALSE	0
395	45700	1974	1948	0	-5,175.00	0	FALSE	0
396	45700	2009	1957	0	-3,952.60	0	FALSE	0
397	45700	2011	1957	8	8,481.84	0	FALSE	0
398	45700	2009	1960	0	-1,739.20	0	FALSE	0
399	45700	2011	1960	8	3,229.85	0	FALSE	0
400	45700	2009	1961	0	-354.20	0	FALSE	0
401	45700	2011	1961	8	657.80	0	FALSE	0
402	45700	2009	1963	0	-547.10	0	FALSE	0
403	45700	2011	1963	8	1,015.95	0	FALSE	0
404	45700	2009	1964	0	-115.20	0	FALSE	0
405	45700	2011	1964	8	213.85	0	FALSE	0
406	45700	2009	1965	0	-220.90	0	FALSE	0
407	45700	2011	1965	8	410.15	0	FALSE	0
408	45700	2009	1966	0	-33.60	0	FALSE	0
409	45700	2011	1966	8	62.60	0	FALSE	0
410	45700	1988	1967	0	-33.00	0	FALSE	0
411	45700	2009	1967	0	-3,165.30	0	FALSE	0
412	45700	2011	1967	8	5,878.36	0	FALSE	0
413	45700	1984	1968	0	-79.00	0	FALSE	0
414	45700	2008	1968	0	-7,355.50	0	FALSE	0
415	45700	2009	1968	0	-35.50	0	FALSE	0
416	45700	2011	1968	8	14,018.01	0	FALSE	0
417	45700	1976	1969	0	-1,349.00	0	FALSE	0
418	45700	2011	1969	8	25,261.00	0	FALSE	0
419	45700	1975	1970	0	-253.00	0	FALSE	0
420	45700	1976	1970	0	-16,423.00	0	FALSE	0
421	45700	2011	1970	8	17,772.00	0	FALSE	0
422	45700	1983	1971	0	-2,888.00	0	FALSE	0
423	45700	1984	1971	0	-118.00	0	FALSE	0

424	45700	2011	1971	8	3,930.00	0		FALSE	0
425	45700	2011	1974	8	41,250.75	0		FALSE	0
426	45700	1987	1975	4	12,434.14	1975		FALSE	0
427	45700	2011	1975	8	143,608.80	0		FALSE	0
428	45700	2011	1981	8	8,150.00	0		FALSE	0
429	45700	2011	1984	8	9,590.00	0		FALSE	0
430	45700	2011	1985	8	14,603.26	0		FALSE	0
431	45700	2011	1986	8	43,015.79	0		FALSE	0
432	45700	2011	1988	8	21,596.39	0		FALSE	0
433	45700	2011	1989	8	18,476.14	0		FALSE	0
434	45700	2001	1992	4	231,307.73	1992		FALSE	0
435	45700	2011	1992	8	231,307.73	0		FALSE	0
436	45700	1994	1993	0	-4,795.70	0		FALSE	0
437	45700	1994	1993	4	5,179.38	1993		FALSE	0
438	45700	2011	1993	8	460,428.37	0		FALSE	0
439	45700	1997	1996	3	-636,810.60	1996		FALSE	0
440	45700	2011	1996	8	147,978.24	0		FALSE	0
441	45700	2001	1997	4	93,710.35	1997		FALSE	0
442	45700	2011	1997	8	94,152.91	0		FALSE	0
443	45700	2011	1999	8	62,040.09	0		FALSE	0
444	45700	2011	2000	8	4,081.39	0		FALSE	0
445	45700	2011	1982	8	3,210.00	0	Record changed as per Client advice	TRUE	0
446	47100	2011	1971	8	1,500.00	0		FALSE	0
447	47100	2011	1979	8	198.05	0		FALSE	0
448	47100	2011	1994	8	12,700.80	0		FALSE	0
449	47100	2011	1995	8	44,975.18	0		FALSE	0
450	47100	2011	1996	8	46,085.52	0		FALSE	0
451	47100	2011	1997	8	140,113.75	0		FALSE	0
452	47100	2011	1998	8	50,522.14	0		FALSE	0
453	47100	2011	1999	8	50,004.19	0		FALSE	0
454	47100	2011	2000	8	49,670.66	0		FALSE	0
455	47100	2011	2001	8	55,348.17	0		FALSE	0
456	47100	2011	2002	8	34,647.85	0		FALSE	0
457	47100	2011	2003	8	1,972.64	0		FALSE	0
458	47100	2011	2004	8	60,926.26	0		FALSE	0
459	47100	2011	2005	8	204,085.51	0		FALSE	0
460	47100	2011	2006	8	46,254.29	0		FALSE	0
461	47100	2008	2007	4	103.77	2007		FALSE	0
462	47100	2011	2007	8	69,728.37	0		FALSE	0
463	47100	2009	2008	3	-99.00	0		FALSE	0
464	47100	2011	2008	8	103,657.56	0		FALSE	0
465	47100	2010	2009	4	1,310.97	0		FALSE	0
466	47100	2011	2009	4	81.68	2009		FALSE	0
467	47100	2011	2009	8	72,924.99	0		FALSE	0
468	47100	2011	2010	3	0.00	2010		FALSE	0
469	47100	2011	2010	8	86,743.57	0		FALSE	0
470	47100	2011	2011	8	75,548.93	0		FALSE	0
471	47300	1960	1945	0	-1,912.00	0		FALSE	0
472	47300	1961	1945	0	-1,441.00	0		FALSE	0
473	47300	1980	1945	0	-1,865.00	0		FALSE	0
474	47300	1961	1946	0	-503.00	0		FALSE	0
475	47300	1980	1946	0	-280.00	0		FALSE	0
476	47300	1961	1947	0	-578.00	0		FALSE	0

477	47300	1980	1947	0	-322.00	0	FALSE	0
478	47300	1961	1948	0	-666.00	0	FALSE	0
479	47300	1980	1948	0	-370.00	0	FALSE	0
480	47300	1961	1949	0	-421.00	0	FALSE	0
481	47300	1962	1949	0	-344.00	0	FALSE	0
482	47300	1980	1949	0	-426.00	0	FALSE	0
483	47300	1962	1950	0	-879.00	0	FALSE	0
484	47300	1980	1950	0	-490.00	0	FALSE	0
485	47300	1962	1951	0	-1,012.00	0	FALSE	0
486	47300	1980	1951	0	-563.00	0	FALSE	0
487	47300	1962	1952	0	-1,551.00	0	FALSE	0
488	47300	1980	1952	0	-863.00	0	FALSE	0
489	47300	1962	1953	0	-149.00	0	FALSE	0
490	47300	1963	1953	0	-641.00	0	FALSE	0
491	47300	1965	1953	0	-271.00	0	FALSE	0
492	47300	1966	1953	0	-367.00	0	FALSE	0
493	47300	1967	1953	0	-306.00	0	FALSE	0
494	47300	1969	1953	0	-944.00	0	FALSE	0
495	47300	1970	1953	0	-114.00	0	FALSE	0
496	47300	1980	1953	0	-1,554.00	0	FALSE	0
497	47300	1970	1954	0	-725.00	0	FALSE	0
498	47300	1971	1954	0	-2,905.00	0	FALSE	0
499	47300	1980	1954	0	-475.00	0	FALSE	0
500	47300	1991	1954	0	-1,125.40	0	FALSE	0
501	47300	1994	1954	0	-109.30	0	FALSE	0
502	47300	1995	1954	0	-101.10	0	FALSE	0
503	47300	1971	1955	0	-423.00	0	FALSE	0
504	47300	1972	1955	0	-165.00	0	FALSE	0
505	47300	1974	1955	0	-2,558.00	0	FALSE	0
506	47300	1978	1955	0	-568.00	0	FALSE	0
507	47300	1995	1955	0	-373.10	0	FALSE	0
508	47300	2002	1955	0	-809.00	0	FALSE	0
509	47300	1974	1956	0	-3,774.00	0	FALSE	0
510	47300	1978	1956	0	-2,101.00	0	FALSE	0
511	47300	1974	1957	0	-269.00	0	FALSE	0
512	47300	1975	1957	0	-2,721.00	0	FALSE	0
513	47300	1976	1957	0	-1,539.00	0	FALSE	0
514	47300	1977	1957	0	-237.00	0	FALSE	0
515	47300	1978	1957	0	-2,284.00	0	FALSE	0
516	47300	1961	1958	0	-103.00	0	FALSE	0
517	47300	1970	1958	0	-1,782.00	0	FALSE	0
518	47300	1971	1958	0	-46.00	0	FALSE	0
519	47300	1972	1958	0	-1,058.00	0	FALSE	0
520	47300	1973	1958	0	-804.00	0	FALSE	0
521	47300	1981	1958	0	-38.00	0	FALSE	0
522	47300	2002	1958	0	-3,465.00	0	FALSE	0
523	47300	2004	1958	0	-2,437.00	0	FALSE	0
524	47300	2005	1958	0	-676.90	0	FALSE	0
525	47300	2006	1958	0	-5,315.60	0	FALSE	0
526	47300	2008	1958	0	-183.40	0	FALSE	0
527	47300	2009	1958	0	-303.30	0	FALSE	0
528	47300	2011	1958	8	3,014.82	0	FALSE	0
529	47300	1961	1959	0	-117.00	0	FALSE	0

530	47300	1962	1959	0	-321.00	0	FALSE	0
531	47300	1963	1959	0	-38.00	0	FALSE	0
532	47300	1965	1959	0	-273.00	0	FALSE	0
533	47300	1967	1959	0	-188.00	0	FALSE	0
534	47300	1969	1959	0	-53.00	0	FALSE	0
535	47300	1971	1959	0	-16.00	0	FALSE	0
536	47300	1972	1959	0	-1,777.00	0	FALSE	0
537	47300	1973	1959	0	-2,674.00	0	FALSE	0
538	47300	1974	1959	0	-1,876.00	0	FALSE	0
539	47300	1975	1959	0	-1,054.00	0	FALSE	0
540	47300	1976	1959	0	-461.00	0	FALSE	0
541	47300	1977	1959	0	-2,191.00	0	FALSE	0
542	47300	2005	1959	0	-36.00	0	FALSE	0
543	47300	2006	1959	0	-2,907.80	0	FALSE	0
544	47300	2008	1959	0	-429.10	0	FALSE	0
545	47300	2009	1959	0	-461.70	0	FALSE	0
546	47300	2010	1959	0	-6,028.70	0	FALSE	0
547	47300	2011	1959	8	3,422.64	0	FALSE	0
548	47300	1960	1960	0	-1,194.00	0	FALSE	0
549	47300	1965	1960	0	-205.00	0	FALSE	0
550	47300	1966	1960	0	-24.00	0	FALSE	0
551	47300	1967	1960	0	-369.00	0	FALSE	0
552	47300	1968	1960	0	-24.00	0	FALSE	0
553	47300	1970	1960	0	-388.00	0	FALSE	0
554	47300	1972	1960	0	-144.00	0	FALSE	0
555	47300	1973	1960	0	-4,372.00	0	FALSE	0
556	47300	1974	1960	0	-124.00	0	FALSE	0
557	47300	1976	1960	0	-58.00	0	FALSE	0
558	47300	1995	1960	0	-2,474.80	0	FALSE	0
559	47300	1996	1960	0	-1,772.70	0	FALSE	0
560	47300	1999	1960	0	-283.30	0	FALSE	0
561	47300	2000	1960	0	-307.40	0	FALSE	0
562	47300	2001	1960	0	-267.90	0	FALSE	0
563	47300	2003	1960	0	-525.80	0	FALSE	0
564	47300	2005	1960	0	-4,267.00	0	FALSE	0
565	47300	2008	1960	0	-1,639.50	0	FALSE	0
566	47300	2009	1960	0	-1,838.70	0	FALSE	0
567	47300	2010	1960	0	-6,799.40	0	FALSE	0
568	47300	2011	1960	8	64,066.35	0	FALSE	0
569	47300	1968	1961	0	-39.00	0	FALSE	0
570	47300	1971	1961	0	-50.00	0	FALSE	0
571	47300	1972	1961	0	-393.00	0	FALSE	0
572	47300	1973	1961	0	-838.00	0	FALSE	0
573	47300	1975	1961	0	-201.00	0	FALSE	0
574	47300	1976	1961	0	-294.00	0	FALSE	0
575	47300	1977	1961	0	-80.00	0	FALSE	0
576	47300	1979	1961	0	-1.00	0	FALSE	0
577	47300	2006	1961	0	-356.90	0	FALSE	0
578	47300	2008	1961	0	-492.40	0	FALSE	0
579	47300	2010	1961	0	-495.90	0	FALSE	0
580	47300	2011	1961	8	22,262.77	0	FALSE	0
581	47300	1963	1962	0	-364.00	0	FALSE	0
582	47300	1971	1962	0	-2,083.00	0	FALSE	0

583	47300	1972	1962	0	-1,242.00	0	FALSE	0
584	47300	1973	1962	0	-203.00	0	FALSE	0
585	47300	1974	1962	0	-514.00	0	FALSE	0
586	47300	1975	1962	0	-260.00	0	FALSE	0
587	47300	1977	1962	0	-7.00	0	FALSE	0
588	47300	1979	1962	0	-549.00	0	FALSE	0
589	47300	1981	1962	0	-814.00	0	FALSE	0
590	47300	1986	1962	0	-225.00	0	FALSE	0
591	47300	1988	1962	0	-301.00	0	FALSE	0
592	47300	2008	1962	0	-389.70	0	FALSE	0
593	47300	2010	1962	0	-392.60	0	FALSE	0
594	47300	2011	1962	8	17,904.69	0	FALSE	0
595	47300	1964	1963	0	-541.00	0	FALSE	0
596	47300	1965	1963	0	-230.00	0	FALSE	0
597	47300	1966	1963	0	-100.00	0	FALSE	0
598	47300	1969	1963	0	-1,377.00	0	FALSE	0
599	47300	1970	1963	0	-10.00	0	FALSE	0
600	47300	1971	1963	0	-614.00	0	FALSE	0
601	47300	1976	1963	0	-187.00	0	FALSE	0
602	47300	1978	1963	0	-422.00	0	FALSE	0
603	47300	1979	1963	0	-2.00	0	FALSE	0
604	47300	1991	1963	0	-23.40	0	FALSE	0
605	47300	2008	1963	0	-485.10	0	FALSE	0
606	47300	2010	1963	0	-37.00	0	FALSE	0
607	47300	2011	1963	8	22,736.58	0	FALSE	0
608	47300	1972	1964	0	-1,875.00	0	FALSE	0
609	47300	1973	1964	0	-338.00	0	FALSE	0
610	47300	1975	1964	0	-368.00	0	FALSE	0
611	47300	1977	1964	0	-25.00	0	FALSE	0
612	47300	1978	1964	0	-107.00	0	FALSE	0
613	47300	1979	1964	0	-42.00	0	FALSE	0
614	47300	1983	1964	0	-1,664.00	0	FALSE	0
615	47300	1984	1964	0	-213.00	0	FALSE	0
616	47300	2004	1964	0	-119.00	0	FALSE	0
617	47300	2008	1964	0	-543.80	0	FALSE	0
618	47300	2011	1964	8	25,528.25	0	FALSE	0
619	47300	1966	1965	0	-381.00	0	FALSE	0
620	47300	1968	1965	0	-37.00	0	FALSE	0
621	47300	1969	1965	0	-521.00	0	FALSE	0
622	47300	1973	1965	0	-74.00	0	FALSE	0
623	47300	1975	1965	0	-52.00	0	FALSE	0
624	47300	1976	1965	0	-54.00	0	FALSE	0
625	47300	1981	1965	0	-283.00	0	FALSE	0
626	47300	1985	1965	0	-39.00	0	FALSE	0
627	47300	1991	1965	0	-139.70	0	FALSE	0
628	47300	1995	1965	0	-503.10	0	FALSE	0
629	47300	1997	1965	0	-338.10	0	FALSE	0
630	47300	1999	1965	0	-1,696.60	0	FALSE	0
631	47300	2001	1965	0	-445.90	0	FALSE	0
632	47300	2002	1965	0	-1,738.80	0	FALSE	0
633	47300	2005	1965	0	-1,506.80	0	FALSE	0
634	47300	2008	1965	0	-1,052.60	0	FALSE	0
635	47300	2011	1965	8	24,225.28	0	FALSE	0

636	47300	1966	1966	0	-19.00	0	FALSE	0
637	47300	1971	1966	0	-126.00	0	FALSE	0
638	47300	1972	1966	0	-764.00	0	FALSE	0
639	47300	1973	1966	0	-138.00	0	FALSE	0
640	47300	1976	1966	0	-4.00	0	FALSE	0
641	47300	1978	1966	0	-890.00	0	FALSE	0
642	47300	1991	1966	0	-233.70	0	FALSE	0
643	47300	2006	1966	0	-171.00	0	FALSE	0
644	47300	2008	1966	0	-396.90	0	FALSE	0
645	47300	2010	1966	0	-359.90	0	FALSE	0
646	47300	2011	1966	0	-567.90	0	FALSE	0
647	47300	2011	1966	8	70,219.67	0	FALSE	0
648	47300	1967	1967	0	-86.00	0	FALSE	0
649	47300	1968	1967	0	-40.00	0	FALSE	0
650	47300	1971	1967	0	-19.00	0	FALSE	0
651	47300	1972	1967	0	-1,634.00	0	FALSE	0
652	47300	1975	1967	0	-42.00	0	FALSE	0
653	47300	1976	1967	0	-47.00	0	FALSE	0
654	47300	1978	1967	0	-1,309.00	0	FALSE	0
655	47300	1979	1967	0	-14.00	0	FALSE	0
656	47300	1981	1967	0	-28.00	0	FALSE	0
657	47300	1988	1967	0	-37.00	0	FALSE	0
658	47300	2001	1967	0	-6,334.70	0	FALSE	0
659	47300	2002	1967	0	-616.60	0	FALSE	0
660	47300	2004	1967	0	-481.10	0	FALSE	0
661	47300	2008	1967	0	-912.00	0	FALSE	0
662	47300	2009	1967	0	-3,582.30	0	FALSE	0
663	47300	2010	1967	0	-2,632.00	0	FALSE	0
664	47300	2011	1967	0	-354.00	0	FALSE	0
665	47300	2011	1967	8	36,246.48	0	FALSE	0
666	47300	1968	1968	0	-17.00	0	FALSE	0
667	47300	1971	1968	0	-1,832.00	0	FALSE	0
668	47300	1972	1968	0	-593.00	0	FALSE	0
669	47300	1973	1968	0	-4,740.00	0	FALSE	0
670	47300	1981	1968	0	-1.00	0	FALSE	0
671	47300	1991	1968	0	-125.30	0	FALSE	0
672	47300	1997	1968	0	-119.60	0	FALSE	0
673	47300	2001	1968	0	-76.90	0	FALSE	0
674	47300	2002	1968	0	-262.00	0	FALSE	0
675	47300	2003	1968	0	-368.80	0	FALSE	0
676	47300	2005	1968	0	-1,138.00	0	FALSE	0
677	47300	2008	1968	0	-8,066.10	0	FALSE	0
678	47300	2009	1968	0	-1,528.70	0	FALSE	0
679	47300	2010	1968	0	-522.00	0	FALSE	0
680	47300	2011	1968	0	-311.00	0	FALSE	0
681	47300	2011	1968	8	96,667.60	0	FALSE	0
682	47300	1971	1969	0	-95.00	0	FALSE	0
683	47300	1983	1969	0	-1,284.00	0	FALSE	0
684	47300	1984	1969	0	-190.00	0	FALSE	0
685	47300	1991	1969	0	-8.50	0	FALSE	0
686	47300	1992	1969	0	-88.90	0	FALSE	0
687	47300	1993	1969	0	-34.10	0	FALSE	0
688	47300	1999	1969	0	-329.70	0	FALSE	0

689	47300	2005	1969	0	-1,126.90	0	FALSE	0
690	47300	2010	1969	0	-167.00	0	FALSE	0
691	47300	2011	1969	8	106,747.78	0	FALSE	0
692	47300	1978	1970	0	-448.00	0	FALSE	0
693	47300	1983	1970	0	-306.00	0	FALSE	0
694	47300	1984	1970	0	-525.00	0	FALSE	0
695	47300	1992	1970	0	-324.80	0	FALSE	0
696	47300	1993	1970	0	-3,093.30	0	FALSE	0
697	47300	1994	1970	0	-3,017.30	0	FALSE	0
698	47300	1995	1970	0	-8,497.40	0	FALSE	0
699	47300	1996	1970	0	-2,801.20	0	FALSE	0
700	47300	1997	1970	0	-833.50	0	FALSE	0
701	47300	1998	1970	0	-4,259.00	0	FALSE	0
702	47300	1999	1970	0	-3,113.20	0	FALSE	0
703	47300	2000	1970	0	-1,402.70	0	FALSE	0
704	47300	2001	1970	0	-2,460.40	0	FALSE	0
705	47300	2002	1970	0	-1,808.70	0	FALSE	0
706	47300	2003	1970	0	-294.90	0	FALSE	0
707	47300	2003	1970	0	-510.20	0	FALSE	0
708	47300	2003	1970	0	-52,120.60	0	FALSE	0
709	47300	2004	1970	0	-1,157.40	0	FALSE	0
710	47300	2005	1970	0	-11,022.00	0	FALSE	0
711	47300	2006	1970	0	-1,184.80	0	FALSE	0
712	47300	2008	1970	0	-2,152.00	0	FALSE	0
713	47300	2009	1970	0	-1,695.00	0	FALSE	0
714	47300	2010	1970	0	-3,788.10	0	FALSE	0
715	47300	2011	1970	0	-461.00	0	FALSE	0
716	47300	2011	1970	8	16,023.49	0	FALSE	0
717	47300	1976	1971	0	-25.00	0	FALSE	0
718	47300	1979	1971	0	-61.00	0	FALSE	0
719	47300	1983	1971	0	-9,121.00	0	FALSE	0
720	47300	1986	1971	0	-7.00	0	FALSE	0
721	47300	1988	1971	0	-279.00	0	FALSE	0
722	47300	1991	1971	0	-180.40	0	FALSE	0
723	47300	1992	1971	0	-22.00	0	FALSE	0
724	47300	1993	1971	0	-268.80	0	FALSE	0
725	47300	1994	1971	0	-40.40	0	FALSE	0
726	47300	1995	1971	0	-137.80	0	FALSE	0
727	47300	1997	1971	0	-666.70	0	FALSE	0
728	47300	2002	1971	0	-189.60	0	FALSE	0
729	47300	2003	1971	0	-805.30	0	FALSE	0
730	47300	2003	1971	0	-1,257.90	0	FALSE	0
731	47300	2003	1971	0	-41.80	0	FALSE	0
732	47300	2005	1971	0	-1,484.30	0	FALSE	0
733	47300	2008	1971	0	-966.00	0	FALSE	0
734	47300	2011	1971	0	-108.00	0	FALSE	0
735	47300	2011	1971	8	18,709.16	0	FALSE	0
736	47300	1977	1972	0	-281.00	0	FALSE	0
737	47300	1980	1972	0	-42.00	0	FALSE	0
738	47300	1981	1972	0	-29.00	0	FALSE	0
739	47300	1983	1972	0	-4,318.00	0	FALSE	0
740	47300	1984	1972	0	-484.00	0	FALSE	0
741	47300	1992	1972	0	-1,440.80	0	FALSE	0

742	47300	1993	1972	0	-616.40	0	FALSE	0
743	47300	1994	1972	0	-42.80	0	FALSE	0
744	47300	2005	1972	0	-1,066.90	0	FALSE	0
745	47300	2006	1972	0	-386.00	0	FALSE	0
746	47300	2007	1972	0	-136.80	0	FALSE	0
747	47300	2008	1972	0	-912.80	0	FALSE	0
748	47300	2009	1972	0	-3,849.40	0	FALSE	0
749	47300	2010	1972	0	-4,111.90	0	FALSE	0
750	47300	2011	1972	0	-904.20	0	FALSE	0
751	47300	2011	1972	8	129,825.22	0	FALSE	0
752	47300	1976	1973	0	-111.00	0	FALSE	0
753	47300	1978	1973	0	-493.00	0	FALSE	0
754	47300	1979	1973	0	-752.00	0	FALSE	0
755	47300	1981	1973	0	-2.00	0	FALSE	0
756	47300	1982	1973	0	-55.00	0	FALSE	0
757	47300	1984	1973	0	-1,544.00	0	FALSE	0
758	47300	1986	1973	0	-318.00	0	FALSE	0
759	47300	1992	1973	0	-2,184.80	0	FALSE	0
760	47300	1993	1973	0	-171.60	0	FALSE	0
761	47300	1994	1973	0	-458.50	0	FALSE	0
762	47300	2007	1973	0	-314.00	0	FALSE	0
763	47300	2008	1973	0	-2,180.00	0	FALSE	0
764	47300	2009	1973	0	-1,207.00	0	FALSE	0
765	47300	2010	1973	0	-1,972.00	0	FALSE	0
766	47300	2011	1973	8	98,707.41	0	FALSE	0
767	47300	1978	1974	0	-451.00	0	FALSE	0
768	47300	1979	1974	0	-23.00	0	FALSE	0
769	47300	1981	1974	0	-60.00	0	FALSE	0
770	47300	1992	1974	0	-311.00	0	FALSE	0
771	47300	1993	1974	0	-283.20	0	FALSE	0
772	47300	1994	1974	0	-253.40	0	FALSE	0
773	47300	1998	1974	0	-167.40	0	FALSE	0
774	47300	2000	1974	0	-1,439.80	0	FALSE	0
775	47300	2008	1974	0	-1,984.60	0	FALSE	0
776	47300	2009	1974	0	-2,708.00	0	FALSE	0
777	47300	2010	1974	0	-5,217.00	0	FALSE	0
778	47300	2011	1974	0	-193.20	0	FALSE	0
779	47300	2011	1974	8	89,544.20	0	FALSE	0
780	47300	1978	1975	0	-706.00	0	FALSE	0
781	47300	1979	1975	0	-4,835.00	0	FALSE	0
782	47300	1981	1975	0	-1,251.00	0	FALSE	0
783	47300	1982	1975	0	-994.00	0	FALSE	0
784	47300	1983	1975	0	-513.00	0	FALSE	0
785	47300	1984	1975	0	-718.00	0	FALSE	0
786	47300	1985	1975	0	-24.00	0	FALSE	0
787	47300	1986	1975	0	-405.00	0	FALSE	0
788	47300	1991	1975	0	-76.10	0	FALSE	0
789	47300	1992	1975	0	-5,130.80	0	FALSE	0
790	47300	1993	1975	0	-105.90	0	FALSE	0
791	47300	1994	1975	0	-225.90	0	FALSE	0
792	47300	1995	1975	0	-486.50	0	FALSE	0
793	47300	1997	1975	0	-3,067.50	0	FALSE	0
794	47300	1998	1975	0	-3,141.80	0	FALSE	0

795	47300	1999	1975	0	-2,685.90	0	FALSE	0
796	47300	2000	1975	0	-4,485.70	0	FALSE	0
797	47300	2001	1975	0	-3,066.10	0	FALSE	0
798	47300	2002	1975	0	-1,330.00	0	FALSE	0
799	47300	2004	1975	0	-359.50	0	FALSE	0
800	47300	2005	1975	0	-3,033.00	0	FALSE	0
801	47300	2006	1975	0	-14,188.00	0	FALSE	0
802	47300	2007	1975	0	-1,367.60	0	FALSE	0
803	47300	2008	1975	0	-2,494.00	0	FALSE	0
804	47300	2009	1975	0	-7,178.40	0	FALSE	0
805	47300	2010	1975	0	-191.00	0	FALSE	0
806	47300	2011	1975	8	146,445.21	0	FALSE	0
807	47300	1978	1976	0	-73.00	0	FALSE	0
808	47300	1979	1976	0	-3.00	0	FALSE	0
809	47300	1981	1976	0	-1,110.00	0	FALSE	0
810	47300	1982	1976	0	-139.00	0	FALSE	0
811	47300	1983	1976	0	-144.00	0	FALSE	0
812	47300	1985	1976	0	-8.00	0	FALSE	0
813	47300	1986	1976	0	-2,090.00	0	FALSE	0
814	47300	1987	1976	0	-733.00	0	FALSE	0
815	47300	1988	1976	0	-4,395.00	0	FALSE	0
816	47300	1989	1976	0	-1,676.00	0	FALSE	0
817	47300	1992	1976	0	-822.50	0	FALSE	0
818	47300	1993	1976	0	-761.10	0	FALSE	0
819	47300	1994	1976	0	-654.30	0	FALSE	0
820	47300	1995	1976	0	-232.90	0	FALSE	0
821	47300	1997	1976	0	-385.10	0	FALSE	0
822	47300	1999	1976	0	-870.90	0	FALSE	0
823	47300	2000	1976	0	-3,284.40	0	FALSE	0
824	47300	2005	1976	0	-300.00	0	FALSE	0
825	47300	2008	1976	0	-782.00	0	FALSE	0
826	47300	2010	1976	0	-2,428.90	0	FALSE	0
827	47300	2011	1976	0	-760.00	0	FALSE	0
828	47300	2011	1976	8	96,229.81	0	FALSE	0
829	47300	1978	1977	0	-2,317.00	0	FALSE	0
830	47300	1979	1977	0	-17.00	0	FALSE	0
831	47300	1981	1977	0	-210.00	0	FALSE	0
832	47300	1982	1977	0	-365.00	0	FALSE	0
833	47300	1983	1977	0	-10.00	0	FALSE	0
834	47300	1984	1977	0	-519.00	0	FALSE	0
835	47300	1985	1977	0	-596.00	0	FALSE	0
836	47300	1986	1977	0	-5,514.00	0	FALSE	0
837	47300	1987	1977	0	-4,236.00	0	FALSE	0
838	47300	1988	1977	0	-29.00	0	FALSE	0
839	47300	1989	1977	0	-121.00	0	FALSE	0
840	47300	1990	1977	0	-3.30	0	FALSE	0
841	47300	1991	1977	0	-218.10	0	FALSE	0
842	47300	1992	1977	0	-118.20	0	FALSE	0
843	47300	1993	1977	0	-2.50	0	FALSE	0
844	47300	1994	1977	0	-2.50	0	FALSE	0
845	47300	1998	1977	0	-62.40	0	FALSE	0
846	47300	2002	1977	0	-897.90	0	FALSE	0
847	47300	2003	1977	0	-37.90	0	FALSE	0

848	47300	2008	1977	0	-2,004.00	0	FALSE	0
849	47300	2009	1977	0	-1,107.70	0	FALSE	0
850	47300	2010	1977	0	-3,028.00	0	FALSE	0
851	47300	2011	1977	8	240,706.63	0	FALSE	0
852	47300	1979	1978	0	-16.00	0	FALSE	0
853	47300	1982	1978	0	-459.00	0	FALSE	0
854	47300	1983	1978	0	-27.00	0	FALSE	0
855	47300	1984	1978	0	-29.00	0	FALSE	0
856	47300	1985	1978	0	-642.00	0	FALSE	0
857	47300	1986	1978	0	-524.00	0	FALSE	0
858	47300	1987	1978	0	-6,143.00	0	FALSE	0
859	47300	1988	1978	0	-22,968.00	0	FALSE	0
860	47300	1989	1978	0	-5,510.00	0	FALSE	0
861	47300	1992	1978	0	-32.00	0	FALSE	0
862	47300	1995	1978	0	-527.40	0	FALSE	0
863	47300	1996	1978	0	-2,329.30	0	FALSE	0
864	47300	1997	1978	0	-253.70	0	FALSE	0
865	47300	2000	1978	0	-657.40	0	FALSE	0
866	47300	2002	1978	0	-116.60	0	FALSE	0
867	47300	2005	1978	0	-2,161.00	0	FALSE	0
868	47300	2007	1978	0	-1,032.00	0	FALSE	0
869	47300	2010	1978	0	-8,507.00	0	FALSE	0
870	47300	2011	1978	0	-83.00	0	FALSE	0
871	47300	2011	1978	8	212,027.14	0	FALSE	0
872	47300	1980	1979	0	-4.00	0	FALSE	0
873	47300	1981	1979	0	-668.00	0	FALSE	0
874	47300	1983	1979	0	-2,271.00	0	FALSE	0
875	47300	1984	1979	0	-2,643.00	0	FALSE	0
876	47300	1985	1979	0	-6.00	0	FALSE	0
877	47300	1986	1979	0	-187.00	0	FALSE	0
878	47300	1987	1979	0	-229.00	0	FALSE	0
879	47300	1988	1979	0	-279.00	0	FALSE	0
880	47300	1989	1979	0	-1,148.00	0	FALSE	0
881	47300	1990	1979	0	-4.80	0	FALSE	0
882	47300	1992	1979	0	-14,687.80	0	FALSE	0
883	47300	1994	1979	0	-224.70	0	FALSE	0
884	47300	2001	1979	0	-1,279.40	0	FALSE	0
885	47300	2003	1979	0	-590.30	0	FALSE	0
886	47300	2006	1979	0	-715.00	0	FALSE	0
887	47300	2008	1979	0	-8,436.50	0	FALSE	0
888	47300	2011	1979	8	200,296.24	0	FALSE	0
889	47300	1985	1980	0	-562.00	0	FALSE	0
890	47300	1986	1980	0	-95.00	0	FALSE	0
891	47300	1987	1980	0	-5.00	0	FALSE	0
892	47300	1988	1980	0	-439.00	0	FALSE	0
893	47300	1992	1980	0	-195.30	0	FALSE	0
894	47300	1993	1980	0	-3,544.80	0	FALSE	0
895	47300	1995	1980	0	-147.90	0	FALSE	0
896	47300	1996	1980	0	-26,346.40	0	FALSE	0
897	47300	1997	1980	0	-32,987.20	0	FALSE	0
898	47300	1998	1980	0	-6,258.00	0	FALSE	0
899	47300	1999	1980	0	-12,964.90	0	FALSE	0
900	47300	2000	1980	0	-33,426.50	0	FALSE	0

901	47300	2001	1980	0	-16,357.20	0	FALSE	0
902	47300	2002	1980	0	-755.70	0	FALSE	0
903	47300	2003	1980	0	-1,901.20	0	FALSE	0
904	47300	2005	1980	0	-17,053.00	0	FALSE	0
905	47300	2006	1980	0	-999.00	0	FALSE	0
906	47300	2007	1980	0	-7,234.90	0	FALSE	0
907	47300	2008	1980	0	-2,867.00	0	FALSE	0
908	47300	2009	1980	0	-3,653.00	0	FALSE	0
909	47300	2010	1980	0	-2,254.00	0	FALSE	0
910	47300	2011	1980	0	-7,210.00	0	FALSE	0
911	47300	2011	1980	8	108,769.20	0	FALSE	0
912	47300	1984	1981	0	-16.00	0	FALSE	0
913	47300	1986	1981	0	-12,368.00	0	FALSE	0
914	47300	1987	1981	0	-375.00	0	FALSE	0
915	47300	1988	1981	0	-1,225.00	0	FALSE	0
916	47300	1989	1981	0	-68.00	0	FALSE	0
917	47300	1990	1981	0	-1,257.00	0	FALSE	0
918	47300	1991	1981	0	-301.80	0	FALSE	0
919	47300	1992	1981	0	-63.20	0	FALSE	0
920	47300	1995	1981	0	-434.00	0	FALSE	0
921	47300	1996	1981	0	-279.40	0	FALSE	0
922	47300	1997	1981	0	-1,773.10	0	FALSE	0
923	47300	1998	1981	0	-451.90	0	FALSE	0
924	47300	2000	1981	0	-15,072.30	0	FALSE	0
925	47300	2001	1981	0	-105.00	0	FALSE	0
926	47300	2002	1981	0	-1,651.00	0	FALSE	0
927	47300	2003	1981	0	-1,169.40	0	FALSE	0
928	47300	2003	1981	0	-105.10	0	FALSE	0
929	47300	2005	1981	0	-1,445.90	0	FALSE	0
930	47300	2006	1981	0	-283.00	0	FALSE	0
931	47300	2008	1981	0	-696.00	0	FALSE	0
932	47300	2009	1981	0	-3,625.70	0	FALSE	0
933	47300	2010	1981	0	-2,788.00	0	FALSE	0
934	47300	2011	1981	0	-19.30	0	FALSE	0
935	47300	2011	1981	8	129,163.87	0	FALSE	0
936	47300	1983	1982	0	-1,053.00	0	FALSE	0
937	47300	1984	1982	0	-355.00	0	FALSE	0
938	47300	1987	1982	0	-1,505.00	0	FALSE	0
939	47300	1988	1982	0	-1,741.00	0	FALSE	0
940	47300	1989	1982	0	-26,195.00	0	FALSE	0
941	47300	1990	1982	0	-348.60	0	FALSE	0
942	47300	1996	1982	0	-77.70	0	FALSE	0
943	47300	1997	1982	0	-1,576.20	0	FALSE	0
944	47300	1998	1982	0	-1,189.00	0	FALSE	0
945	47300	2001	1982	0	-1,487.30	0	FALSE	0
946	47300	2001	1982	0	-5,403.70	0	FALSE	0
947	47300	2002	1982	0	-1,487.30	0	FALSE	0
948	47300	2003	1982	0	-838.00	0	FALSE	0
949	47300	2003	1982	0	-2,983.90	0	FALSE	0
950	47300	2008	1982	0	-1,569.00	0	FALSE	0
951	47300	2011	1982	8	354,099.48	0	FALSE	0
952	47300	1986	1983	0	-1,177.00	0	FALSE	0
953	47300	1987	1983	0	-10,174.00	0	FALSE	0

954	47300	1988	1983	0	-841.00	0	FALSE	0
955	47300	1989	1983	0	-3,338.00	0	FALSE	0
956	47300	1990	1983	0	-7,808.00	0	FALSE	0
957	47300	1991	1983	0	-875.40	0	FALSE	0
958	47300	1997	1983	0	-1,349.40	0	FALSE	0
959	47300	1998	1983	0	-116.70	0	FALSE	0
960	47300	2001	1983	0	-116.70	0	FALSE	0
961	47300	2002	1983	0	-369.20	0	FALSE	0
962	47300	2011	1983	8	135,039.76	0	FALSE	0
963	47300	1987	1984	0	-32.00	0	FALSE	0
964	47300	1988	1984	0	-7,805.00	0	FALSE	0
965	47300	1989	1984	0	-6,336.00	0	FALSE	0
966	47300	1990	1984	0	-7,129.80	0	FALSE	0
967	47300	1991	1984	0	-3,239.50	0	FALSE	0
968	47300	1992	1984	0	-1.00	0	FALSE	0
969	47300	1994	1984	0	-229.80	0	FALSE	0
970	47300	1995	1984	0	-4,500.00	0	FALSE	0
971	47300	1997	1984	0	-856.10	0	FALSE	0
972	47300	1998	1984	0	-379.40	0	FALSE	0
973	47300	1999	1984	0	-7,020.00	0	FALSE	0
974	47300	2000	1984	0	-3,570.10	0	FALSE	0
975	47300	2001	1984	0	-122.30	0	FALSE	0
976	47300	2002	1984	0	-213.90	0	FALSE	0
977	47300	2003	1984	0	-122.30	0	FALSE	0
978	47300	2003	1984	0	-122.30	0	FALSE	0
979	47300	2003	1984	0	-137.10	0	FALSE	0
980	47300	2004	1984	0	-122.30	0	FALSE	0
981	47300	2006	1984	0	-16,209.00	0	FALSE	0
982	47300	2008	1984	0	-2,248.00	0	FALSE	0
983	47300	2009	1984	0	-1,439.00	0	FALSE	0
984	47300	2010	1984	0	-2,587.50	0	FALSE	0
985	47300	2011	1984	8	273,619.23	0	FALSE	0
986	47300	1989	1985	0	-758.00	0	FALSE	0
987	47300	1990	1985	0	-1,694.40	0	FALSE	0
988	47300	1991	1985	0	-13.90	0	FALSE	0
989	47300	1994	1985	0	-74.00	0	FALSE	0
990	47300	1995	1985	0	-327.10	0	FALSE	0
991	47300	1997	1985	0	-8,678.90	0	FALSE	0
992	47300	1998	1985	0	-5,831.10	0	FALSE	0
993	47300	1999	1985	0	-4,580.70	0	FALSE	0
994	47300	2000	1985	0	-8,754.90	0	FALSE	0
995	47300	2001	1985	0	-1,160.80	0	FALSE	0
996	47300	2002	1985	0	-3,306.00	0	FALSE	0
997	47300	2003	1985	0	-323.10	0	FALSE	0
998	47300	2003	1985	0	-292.50	0	FALSE	0
999	47300	2003	1985	0	-296.30	0	FALSE	0
1000	47300	2003	1985	0	-686.90	0	FALSE	0
1001	47300	2003	1985	0	-642.40	0	FALSE	0
1002	47300	2004	1985	0	-126.90	0	FALSE	0
1003	47300	2005	1985	0	-3,834.40	0	FALSE	0
1004	47300	2006	1985	0	-6,337.70	0	FALSE	0
1005	47300	2007	1985	0	-205.00	0	FALSE	0
1006	47300	2008	1985	0	-2,045.00	0	FALSE	0

1007	47300	2009	1985	0	-3,819.00	0	FALSE	0
1008	47300	2010	1985	0	-3,723.00	0	FALSE	0
1009	47300	2011	1985	8	754,437.87	0	FALSE	0
1010	47300	1987	1986	0	-70.00	0	FALSE	0
1011	47300	1988	1986	0	-381.00	0	FALSE	0
1012	47300	1995	1986	0	-1,161.50	0	FALSE	0
1013	47300	1996	1986	0	-1,301.40	0	FALSE	0
1014	47300	1997	1986	0	-120.70	0	FALSE	0
1015	47300	1998	1986	0	-473.20	0	FALSE	0
1016	47300	1999	1986	0	-664.60	0	FALSE	0
1017	47300	2004	1986	0	-287.90	0	FALSE	0
1018	47300	2005	1986	0	-3,887.00	0	FALSE	0
1019	47300	2009	1986	0	-1,453.00	0	FALSE	0
1020	47300	2010	1986	0	-3,316.80	0	FALSE	0
1021	47300	2011	1986	8	279,561.30	0	FALSE	0
1022	47300	1988	1987	0	-202.00	0	FALSE	0
1023	47300	1996	1987	0	-353.40	0	FALSE	0
1024	47300	1997	1987	0	-1,616.70	0	FALSE	0
1025	47300	2000	1987	0	-1,915.10	0	FALSE	0
1026	47300	2001	1987	0	-1,332.90	0	FALSE	0
1027	47300	2002	1987	0	-682.50	0	FALSE	0
1028	47300	2003	1987	0	-694.50	0	FALSE	0
1029	47300	2003	1987	0	-136.30	0	FALSE	0
1030	47300	2003	1987	0	-596.00	0	FALSE	0
1031	47300	2003	1987	0	-490.90	0	FALSE	0
1032	47300	2007	1987	0	-689.00	0	FALSE	0
1033	47300	2010	1987	0	-7,152.90	0	FALSE	0
1034	47300	2011	1987	8	417,946.08	0	FALSE	0
1035	47300	1990	1988	0	-9.90	0	FALSE	0
1036	47300	1991	1988	0	-3,223.50	0	FALSE	0
1037	47300	1996	1988	0	-2,642.10	0	FALSE	0
1038	47300	1997	1988	0	-827.70	0	FALSE	0
1039	47300	1998	1988	0	-3,706.20	0	FALSE	0
1040	47300	1999	1988	0	-1,906.20	0	FALSE	0
1041	47300	2000	1988	0	-3,300.80	0	FALSE	0
1042	47300	2001	1988	0	-3,395.70	0	FALSE	0
1043	47300	2002	1988	0	-2,201.00	0	FALSE	0
1044	47300	2003	1988	0	-143.10	0	FALSE	0
1045	47300	2003	1988	0	-13,741.70	0	FALSE	0
1046	47300	2010	1988	0	-1,133.00	0	FALSE	0
1047	47300	2011	1988	8	333,623.95	0	FALSE	0
1048	47300	1995	1989	0	-1,052.50	0	FALSE	0
1049	47300	1996	1989	0	-1,436.30	0	FALSE	0
1050	47300	1997	1989	0	-1,915.30	0	FALSE	0
1051	47300	1998	1989	0	-451.80	0	FALSE	0
1052	47300	1999	1989	0	-4,000.20	0	FALSE	0
1053	47300	2008	1989	0	-1,419.00	0	FALSE	0
1054	47300	2009	1989	0	-4,252.00	0	FALSE	0
1055	47300	2010	1989	0	-19.40	0	FALSE	0
1056	47300	2011	1989	8	575,010.94	0	FALSE	0
1057	47300	1995	1990	0	-675.20	0	FALSE	0
1058	47300	1996	1990	0	-1,752.90	0	FALSE	0
1059	47300	1997	1990	0	-2,130.10	0	FALSE	0

1060	47300	1998	1990	0	-3,824.30	0	FALSE	0
1061	47300	1999	1990	0	-18,920.00	0	FALSE	0
1062	47300	2000	1990	0	-5,124.20	0	FALSE	0
1063	47300	2001	1990	0	-2,779.30	0	FALSE	0
1064	47300	2002	1990	0	-4,598.50	0	FALSE	0
1065	47300	2003	1990	0	-210.50	0	FALSE	0
1066	47300	2003	1990	0	-7,267.30	0	FALSE	0
1067	47300	2004	1990	0	-469.10	0	FALSE	0
1068	47300	2005	1990	0	-3,729.00	0	FALSE	0
1069	47300	2008	1990	0	-3,022.00	0	FALSE	0
1070	47300	2009	1990	0	-256.00	0	FALSE	0
1071	47300	2010	1990	0	-3,004.30	0	FALSE	0
1072	47300	2011	1990	0	-309.00	0	FALSE	0
1073	47300	2011	1990	8	1,110,346.89	0	FALSE	0
1074	47300	1998	1991	0	-442.30	0	FALSE	0
1075	47300	1999	1991	0	-294.90	0	FALSE	0
1076	47300	2002	1991	0	-147.50	0	FALSE	0
1077	47300	2003	1991	0	-933.50	0	FALSE	0
1078	47300	2004	1991	0	-1,428.00	0	FALSE	0
1079	47300	2009	1991	0	-309.00	0	FALSE	0
1080	47300	2010	1991	0	-3,027.60	0	FALSE	0
1081	47300	2011	1991	8	782,222.41	0	FALSE	0
1082	47300	1993	1992	4	5,618.94	1992	FALSE	0
1083	47300	1994	1992	0	-387.20	0	FALSE	0
1084	47300	1995	1992	0	-3,654.50	0	FALSE	0
1085	47300	1997	1992	0	-13,200.30	0	FALSE	0
1086	47300	1998	1992	0	-3,132.70	0	FALSE	0
1087	47300	2000	1992	0	-292.00	0	FALSE	0
1088	47300	2002	1992	0	-438.00	0	FALSE	0
1089	47300	2003	1992	0	-5,842.70	0	FALSE	0
1090	47300	2004	1992	0	-491.40	0	FALSE	0
1091	47300	2006	1992	0	-10,084.00	0	FALSE	0
1092	47300	2009	1992	0	-1,780.00	0	FALSE	0
1093	47300	2011	1992	8	1,164,266.14	0	FALSE	0
1094	47300	1994	1993	0	-557.70	0	FALSE	0
1095	47300	1994	1993	4	57,771.17	1993	FALSE	0
1096	47300	1995	1993	0	-134.20	0	FALSE	0
1097	47300	1996	1993	0	-557.60	0	FALSE	0
1098	47300	1996	1993	3	-117,325.20	1993	FALSE	0
1099	47300	1997	1993	0	-67.10	0	FALSE	0
1100	47300	2002	1993	0	-67.10	0	FALSE	0
1101	47300	2005	1993	0	-668.00	0	FALSE	0
1102	47300	2008	1993	0	-27,146.90	0	FALSE	0
1103	47300	2009	1993	0	-305.00	0	FALSE	0
1104	47300	2010	1993	0	-2,064.80	0	FALSE	0
1105	47300	2011	1993	8	1,574,269.86	0	FALSE	0
1106	47300	1994	1994	4	1,965.79	1994	FALSE	0
1107	47300	1995	1994	0	-1,274.60	0	FALSE	0
1108	47300	1996	1994	0	-1,356.10	0	FALSE	0
1109	47300	1997	1994	0	-351.30	0	FALSE	0
1110	47300	1998	1994	0	-292.00	0	FALSE	0
1111	47300	1999	1994	0	-214.40	0	FALSE	0
1112	47300	2002	1994	0	-1,162.00	0	FALSE	0

1113	47300	2004	1994	0	-146.00	0	FALSE	0
1114	47300	2010	1994	0	-1,605.00	0	FALSE	0
1115	47300	2011	1994	8	1,005,504.27	0	FALSE	0
1116	47300	1996	1995	0	-4,589.20	0	FALSE	0
1117	47300	1996	1995	4	100,000.00	1995	FALSE	0
1118	47300	1997	1995	0	-4,600.00	0	FALSE	0
1119	47300	1998	1995	0	-5,726.50	0	FALSE	0
1120	47300	2000	1995	0	-1,066.90	0	FALSE	0
1121	47300	2001	1995	0	-469.20	0	FALSE	0
1122	47300	2002	1995	0	-2,688.10	0	FALSE	0
1123	47300	2003	1995	0	-641.40	0	FALSE	0
1124	47300	2003	1995	0	-186.00	0	FALSE	0
1125	47300	2004	1995	0	-146.90	0	FALSE	0
1126	47300	2005	1995	0	-7,619.00	0	FALSE	0
1127	47300	2006	1995	0	-309.00	0	FALSE	0
1128	47300	2008	1995	0	-158.00	0	FALSE	0
1129	47300	2009	1995	0	-303.00	0	FALSE	0
1130	47300	2010	1995	0	-11,336.00	0	FALSE	0
1131	47300	2011	1995	0	-543.10	0	FALSE	0
1132	47300	2011	1995	8	900,750.05	0	FALSE	0
1133	47300	1997	1996	4	311,210.93	1996	FALSE	0
1134	47300	1998	1996	0	-1,153.50	0	FALSE	0
1135	47300	1999	1996	0	-67.90	0	FALSE	0
1136	47300	2002	1996	0	-460.00	0	FALSE	0
1137	47300	2008	1996	0	-3,958.00	0	FALSE	0
1138	47300	2011	1996	8	899,513.01	0	FALSE	0
1139	47300	1997	1997	3	-16,661.90	1997	FALSE	0
1140	47300	1999	1997	0	-703.10	0	FALSE	0
1141	47300	2000	1997	0	-1,388.60	0	FALSE	0
1142	47300	2001	1997	0	-145.90	0	FALSE	0
1143	47300	2002	1997	0	-974.80	0	FALSE	0
1144	47300	2003	1997	0	-538.40	0	FALSE	0
1145	47300	2004	1997	0	-67.10	0	FALSE	0
1146	47300	2005	1997	0	-103.00	0	FALSE	0
1147	47300	2011	1997	8	770,189.70	0	FALSE	0
1148	47300	2001	1998	0	-4,408.90	0	FALSE	0
1149	47300	2002	1998	0	-1,060.00	0	FALSE	0
1150	47300	2004	1998	0	-680.30	0	FALSE	0
1151	47300	2005	1998	0	-756.90	0	FALSE	0
1152	47300	2006	1998	0	-162.00	0	FALSE	0
1153	47300	2008	1998	0	-468.00	0	FALSE	0
1154	47300	2011	1998	8	679,543.24	0	FALSE	0
1155	47300	2000	1999	4	109,742.80	1999	FALSE	0
1156	47300	2001	1999	0	-1,822.70	0	FALSE	0
1157	47300	2002	1999	0	-220.20	0	FALSE	0
1158	47300	2003	1999	0	-150.80	0	FALSE	0
1159	47300	2003	1999	0	-69.30	0	FALSE	0
1160	47300	2003	1999	0	-150.80	0	FALSE	0
1161	47300	2003	1999	0	-150.80	0	FALSE	0
1162	47300	2006	1999	0	-630.00	0	FALSE	0
1163	47300	2009	1999	0	-669.00	0	FALSE	0
1164	47300	2010	1999	0	-2,125.60	0	FALSE	0
1165	47300	2011	1999	8	766,596.42	0	FALSE	0

1166	47300	2001	2000	0	-622.50	0	FALSE	0
1167	47300	2001	2000	3	-13,576.10	2000	FALSE	0
1168	47300	2002	2000	0	-2,670.30	0	FALSE	0
1169	47300	2003	2000	0	-956.80	0	FALSE	0
1170	47300	2005	2000	0	-745.00	0	FALSE	0
1171	47300	2006	2000	0	-4,519.00	0	FALSE	0
1172	47300	2008	2000	0	-2,426.00	0	FALSE	0
1173	47300	2009	2000	0	-3,668.00	0	FALSE	0
1174	47300	2010	2000	0	-2,333.00	0	FALSE	0
1175	47300	2011	2000	8	612,683.04	0	FALSE	0
1176	47300	2002	2001	0	-1,400.70	0	FALSE	0
1177	47300	2003	2001	0	-74.70	0	FALSE	0
1178	47300	2003	2001	0	-73.70	0	FALSE	0
1179	47300	2004	2001	0	-73.70	0	FALSE	0
1180	47300	2006	2001	0	-702.00	0	FALSE	0
1181	47300	2011	2001	8	636,466.49	0	FALSE	0
1182	47300	2002	2002	0	-539.80	0	FALSE	0
1183	47300	2003	2002	0	-3,261.30	0	FALSE	0
1184	47300	2003	2002	0	-93.40	0	FALSE	0
1185	47300	2004	2002	0	-7,042.10	0	FALSE	0
1186	47300	2006	2002	0	-258.00	0	FALSE	0
1187	47300	2011	2002	8	985,772.90	0	FALSE	0
1188	47300	2005	2003	0	-2,462.00	0	FALSE	0
1189	47300	2011	2003	8	775,635.83	0	FALSE	0
1190	47300	2005	2004	0	-2,680.40	0	FALSE	0
1191	47300	2007	2004	0	-342.10	0	FALSE	0
1192	47300	2008	2004	0	-5,442.00	0	FALSE	0
1193	47300	2009	2004	0	-786.00	0	FALSE	0
1194	47300	2011	2004	8	1,281,162.37	0	FALSE	0
1195	47300	2008	2005	3	-195.00	2005	FALSE	0
1196	47300	2010	2005	0	-2,542.30	0	FALSE	0
1197	47300	2011	2005	8	989,206.22	0	FALSE	0
1198	47300	2008	2006	4	269.33	2006	FALSE	0
1199	47300	2009	2006	0	-435.90	0	FALSE	0
1200	47300	2009	2006	4	1,267.15	0	FALSE	0
1201	47300	2011	2006	8	1,401,831.25	0	FALSE	0
1202	47300	2008	2007	4	31,740.11	2007	FALSE	0
1203	47300	2009	2007	0	-722.10	0	FALSE	0
1204	47300	2009	2007	4	12,662.99	0	FALSE	0
1205	47300	2010	2007	3	-2,703.30	0	FALSE	0
1206	47300	2011	2007	3	-6.90	2007	FALSE	0
1207	47300	2011	2007	8	1,091,993.21	0	FALSE	0
1208	47300	2009	2008	0	-4,412.70	0	FALSE	0
1209	47300	2009	2008	4	18,640.19	0	FALSE	0
1210	47300	2010	2008	0	-15,837.00	0	FALSE	0
1211	47300	2010	2008	3	-2,236.30	0	FALSE	0
1212	47300	2011	2008	8	1,616,156.35	0	FALSE	0
1213	47300	2010	2009	0	-10,833.70	0	FALSE	0
1214	47300	2010	2009	4	16,023.84	0	FALSE	0
1215	47300	2011	2009	4	27,092.62	2009	FALSE	0
1216	47300	2011	2009	8	327,095.60	0	FALSE	0
1217	47300	2011	2010	4	155,028.07	2010	FALSE	0
1218	47300	2011	2010	8	874,751.64	0	FALSE	0

1219	47300	2011	2011	8	2,882,760.32	0	FALSE	0
1220	47300	2001	1988	0	143.10	0 Orig 9844 for install corrected for suspected misalignment - insignificant amt seems be a double entry: net off	TRUE	0
1221	47400	1960	1945	0	-531.00	0	FALSE	0
1222	47400	1961	1945	0	-1,234.00	0	FALSE	0
1223	47400	1980	1945	0	-2,437.00	0	FALSE	0
1224	47400	1961	1946	0	-95.00	0	FALSE	0
1225	47400	1962	1946	0	-170.00	0	FALSE	0
1226	47400	1980	1946	0	-365.00	0	FALSE	0
1227	47400	1962	1947	0	-305.00	0	FALSE	0
1228	47400	1980	1947	0	-420.00	0	FALSE	0
1229	47400	1962	1948	0	-350.00	0	FALSE	0
1230	47400	1980	1948	0	-110.00	0	FALSE	0
1231	47400	1991	1948	0	-96.60	0	FALSE	0
1232	47400	2010	1948	0	-100.10	0	FALSE	0
1233	47400	2011	1948	0	-7.00	0	FALSE	0
1234	47400	2011	1948	8	148.71	0	FALSE	0
1235	47400	1962	1949	0	-402.00	0	FALSE	0
1236	47400	1991	1949	0	-69.40	0	FALSE	0
1237	47400	2011	1949	8	510.02	0	FALSE	0
1238	47400	1962	1950	0	-463.00	0	FALSE	0
1239	47400	1995	1950	0	-30.60	0	FALSE	0
1240	47400	2002	1950	0	-470.20	0	FALSE	0
1241	47400	2005	1950	0	-5.00	0	FALSE	0
1242	47400	2011	1950	8	123.73	0	FALSE	0
1243	47400	1962	1951	0	-367.00	0	FALSE	0
1244	47400	1963	1951	0	-165.00	0	FALSE	0
1245	47400	2011	1951	8	739.89	0	FALSE	0
1246	47400	1963	1952	0	-816.00	0	FALSE	0
1247	47400	2011	1952	8	1,127.00	0	FALSE	0
1248	47400	1963	1953	0	-1,033.00	0	FALSE	0
1249	47400	1965	1953	0	-436.00	0	FALSE	0
1250	47400	2011	1953	8	2,029.00	0	FALSE	0
1251	47400	1965	1954	0	-1,495.00	0	FALSE	0
1252	47400	1967	1954	0	-178.00	0	FALSE	0
1253	47400	1969	1954	0	-236.00	0	FALSE	0
1254	47400	2011	1954	8	2,638.00	0	FALSE	0
1255	47400	1969	1955	0	-137.00	0	FALSE	0
1256	47400	1970	1955	0	-414.00	0	FALSE	0
1257	47400	1971	1955	0	-1,104.00	0	FALSE	0
1258	47400	2004	1955	0	-643.70	0	FALSE	0
1259	47400	2010	1955	0	-971.00	0	FALSE	0
1260	47400	2011	1955	0	-253.00	0	FALSE	0
1261	47400	2011	1955	8	418.31	0	FALSE	0
1262	47400	1971	1956	0	-778.00	0	FALSE	0
1263	47400	1973	1956	0	-120.00	0	FALSE	0
1264	47400	1974	1956	0	-1,088.00	0	FALSE	0
1265	47400	2011	1956	8	2,743.00	0	FALSE	0
1266	47400	1974	1957	0	-584.00	0	FALSE	0
1267	47400	1975	1957	0	-474.00	0	FALSE	0
1268	47400	1976	1957	0	-142.00	0	FALSE	0
1269	47400	1978	1957	0	-2,354.00	0	FALSE	0
1270	47400	2008	1957	0	-14.90	0	FALSE	0
1271	47400	2011	1957	8	922.06	0	FALSE	0

1272	47400	1961	1958	0	-33.00	0	FALSE	0
1273	47400	1962	1958	0	-593.00	0	FALSE	0
1274	47400	1963	1958	0	-382.00	0	FALSE	0
1275	47400	1970	1958	0	-259.00	0	FALSE	0
1276	47400	1971	1958	0	-70.00	0	FALSE	0
1277	47400	1972	1958	0	-969.00	0	FALSE	0
1278	47400	1981	1958	0	-57.00	0	FALSE	0
1279	47400	2011	1958	8	5,559.00	0	FALSE	0
1280	47400	1961	1959	0	-1,445.00	0	FALSE	0
1281	47400	1963	1959	0	-102.00	0	FALSE	0
1282	47400	1965	1959	0	-402.00	0	FALSE	0
1283	47400	1967	1959	0	-103.00	0	FALSE	0
1284	47400	1969	1959	0	-27.00	0	FALSE	0
1285	47400	1971	1959	0	-763.00	0	FALSE	0
1286	47400	1972	1959	0	-2,087.00	0	FALSE	0
1287	47400	1973	1959	0	-1,861.00	0	FALSE	0
1288	47400	1974	1959	0	-2,732.00	0	FALSE	0
1289	47400	1975	1959	0	-396.00	0	FALSE	0
1290	47400	1976	1959	0	-26.00	0	FALSE	0
1291	47400	1977	1959	0	-1,159.00	0	FALSE	0
1292	47400	2011	1959	8	8,040.00	0	FALSE	0
1293	47400	1960	1960	0	-798.00	0	FALSE	0
1294	47400	1961	1960	0	-419.00	0	FALSE	0
1295	47400	1965	1960	0	-83.00	0	FALSE	0
1296	47400	1966	1960	0	-6.00	0	FALSE	0
1297	47400	1967	1960	0	-205.00	0	FALSE	0
1298	47400	1968	1960	0	-91.00	0	FALSE	0
1299	47400	1970	1960	0	-249.00	0	FALSE	0
1300	47400	1973	1960	0	-2,523.00	0	FALSE	0
1301	47400	1974	1960	0	-458.00	0	FALSE	0
1302	47400	1975	1960	0	-69.00	0	FALSE	0
1303	47400	1976	1960	0	-36.00	0	FALSE	0
1304	47400	1977	1960	0	-15.00	0	FALSE	0
1305	47400	1978	1960	0	-3,854.00	0	FALSE	0
1306	47400	1995	1960	0	-318.70	0	FALSE	0
1307	47400	1996	1960	0	-139.90	0	FALSE	0
1308	47400	1999	1960	0	-7.10	0	FALSE	0
1309	47400	2000	1960	0	-83.10	0	FALSE	0
1310	47400	2001	1960	0	-0.90	0	FALSE	0
1311	47400	2005	1960	0	-936.00	0	FALSE	0
1312	47400	2010	1960	0	-136.00	0	FALSE	0
1313	47400	2011	1960	8	72,384.01	0	FALSE	0
1314	47400	1971	1961	0	-87.00	0	FALSE	0
1315	47400	1972	1961	0	-267.00	0	FALSE	0
1316	47400	1973	1961	0	-2,866.00	0	FALSE	0
1317	47400	1975	1961	0	-161.00	0	FALSE	0
1318	47400	1976	1961	0	-327.00	0	FALSE	0
1319	47400	1978	1961	0	-5,187.00	0	FALSE	0
1320	47400	1979	1961	0	-18.00	0	FALSE	0
1321	47400	2011	1961	8	9,293.00	0	FALSE	0
1322	47400	1963	1962	0	-132.00	0	FALSE	0
1323	47400	1971	1962	0	-2,088.00	0	FALSE	0
1324	47400	1972	1962	0	-228.00	0	FALSE	0

1325	47400	1973	1962	0	-41.00	0	FALSE	0
1326	47400	1974	1962	0	-151.00	0	FALSE	0
1327	47400	1975	1962	0	-130.00	0	FALSE	0
1328	47400	1976	1962	0	-107.00	0	FALSE	0
1329	47400	1979	1962	0	-127.00	0	FALSE	0
1330	47400	1981	1962	0	-415.00	0	FALSE	0
1331	47400	1988	1962	0	-1.00	0	FALSE	0
1332	47400	2011	1962	8	12,100.41	0	FALSE	0
1333	47400	1964	1963	0	-41.00	0	FALSE	0
1334	47400	1965	1963	0	-211.00	0	FALSE	0
1335	47400	1966	1963	0	-138.00	0	FALSE	0
1336	47400	1969	1963	0	-1,191.00	0	FALSE	0
1337	47400	1970	1963	0	-39.00	0	FALSE	0
1338	47400	1971	1963	0	-203.00	0	FALSE	0
1339	47400	1976	1963	0	-116.00	0	FALSE	0
1340	47400	1978	1963	0	-1,258.00	0	FALSE	0
1341	47400	1979	1963	0	-63.00	0	FALSE	0
1342	47400	1991	1963	0	-142.90	0	FALSE	0
1343	47400	1992	1963	0	-5.90	0	FALSE	0
1344	47400	2011	1963	8	14,243.14	0	FALSE	0
1345	47400	1972	1964	0	-1,862.00	0	FALSE	0
1346	47400	1973	1964	0	-54.00	0	FALSE	0
1347	47400	1975	1964	0	-188.00	0	FALSE	0
1348	47400	1978	1964	0	-58.00	0	FALSE	0
1349	47400	1979	1964	0	-17.00	0	FALSE	0
1350	47400	1983	1964	0	-629.00	0	FALSE	0
1351	47400	1984	1964	0	-181.00	0	FALSE	0
1352	47400	2004	1964	0	-106.20	0	FALSE	0
1353	47400	2010	1964	0	-462.30	0	FALSE	0
1354	47400	2011	1964	8	10,540.74	0	FALSE	0
1355	47400	1966	1965	0	-96.00	0	FALSE	0
1356	47400	1968	1965	0	-7.00	0	FALSE	0
1357	47400	1969	1965	0	-104.00	0	FALSE	0
1358	47400	1972	1965	0	-158.00	0	FALSE	0
1359	47400	1973	1965	0	-80.00	0	FALSE	0
1360	47400	1975	1965	0	-9.00	0	FALSE	0
1361	47400	1976	1965	0	-19.00	0	FALSE	0
1362	47400	1981	1965	0	-117.00	0	FALSE	0
1363	47400	1985	1965	0	-370.00	0	FALSE	0
1364	47400	1991	1965	0	-31.40	0	FALSE	0
1365	47400	1995	1965	0	-121.70	0	FALSE	0
1366	47400	1997	1965	0	-23.30	0	FALSE	0
1367	47400	1999	1965	0	-204.90	0	FALSE	0
1368	47400	2001	1965	0	-29.00	0	FALSE	0
1369	47400	2002	1965	0	-130.80	0	FALSE	0
1370	47400	2010	1965	0	-1,800.30	0	FALSE	0
1371	47400	2011	1965	8	14,565.83	0	FALSE	0
1372	47400	1966	1966	0	-87.00	0	FALSE	0
1373	47400	1971	1966	0	-114.00	0	FALSE	0
1374	47400	1972	1966	0	-402.00	0	FALSE	0
1375	47400	1973	1966	0	-194.00	0	FALSE	0
1376	47400	1976	1966	0	-156.00	0	FALSE	0
1377	47400	1978	1966	0	-113.00	0	FALSE	0

1378	47400	1991	1966	0	-83.10	0	FALSE	0
1379	47400	2010	1966	0	-2,734.60	0	FALSE	0
1380	47400	2011	1966	8	43,767.33	0	FALSE	0
1381	47400	1967	1967	0	-184.00	0	FALSE	0
1382	47400	1968	1967	0	-249.00	0	FALSE	0
1383	47400	1971	1967	0	-761.00	0	FALSE	0
1384	47400	1972	1967	0	-2,027.00	0	FALSE	0
1385	47400	1975	1967	0	-53.00	0	FALSE	0
1386	47400	1978	1967	0	-435.00	0	FALSE	0
1387	47400	1979	1967	0	-51.00	0	FALSE	0
1388	47400	1988	1967	0	-6.00	0	FALSE	0
1389	47400	2001	1967	0	-969.90	0	FALSE	0
1390	47400	2002	1967	0	-143.60	0	FALSE	0
1391	47400	2004	1967	0	-137.90	0	FALSE	0
1392	47400	2009	1967	0	-7.00	0	FALSE	0
1393	47400	2010	1967	0	-79.00	0	FALSE	0
1394	47400	2011	1967	8	35,893.76	0	FALSE	0
1395	47400	1968	1968	0	-107.00	0	FALSE	0
1396	47400	1971	1968	0	-996.00	0	FALSE	0
1397	47400	1972	1968	0	-119.00	0	FALSE	0
1398	47400	1973	1968	0	-6,228.00	0	FALSE	0
1399	47400	1983	1968	0	-267.00	0	FALSE	0
1400	47400	1984	1968	4	62.00	1968	FALSE	0
1401	47400	1991	1968	0	-27.60	0	FALSE	0
1402	47400	1997	1968	0	-9.00	0	FALSE	0
1403	47400	2001	1968	0	-36.60	0	FALSE	0
1404	47400	2002	1968	0	-117.70	0	FALSE	0
1405	47400	2003	1968	0	-12.70	0	FALSE	0
1406	47400	2008	1968	0	-7.00	0	FALSE	0
1407	47400	2011	1968	8	68,248.09	0	FALSE	0
1408	47400	1971	1969	0	-67.00	0	FALSE	0
1409	47400	1979	1969	0	-53.00	0	FALSE	0
1410	47400	1983	1969	0	-63.00	0	FALSE	0
1411	47400	1984	1969	0	-189.00	0	FALSE	0
1412	47400	1991	1969	0	-40.80	0	FALSE	0
1413	47400	1992	1969	0	-17.00	0	FALSE	0
1414	47400	1993	1969	0	-121.10	0	FALSE	0
1415	47400	1999	1969	0	-122.10	0	FALSE	0
1416	47400	2005	1969	0	-24.90	0	FALSE	0
1417	47400	2006	1969	0	-85.00	0	FALSE	0
1418	47400	2011	1969	8	125,172.05	0	FALSE	0
1419	47400	1978	1970	0	-83.00	0	FALSE	0
1420	47400	1983	1970	0	-597.00	0	FALSE	0
1421	47400	1984	1970	0	-370.00	0	FALSE	0
1422	47400	1992	1970	0	-143.50	0	FALSE	0
1423	47400	1993	1970	0	-1,673.50	0	FALSE	0
1424	47400	1994	1970	0	-450.20	0	FALSE	0
1425	47400	1995	1970	0	-1,638.00	0	FALSE	0
1426	47400	1996	1970	0	-952.80	0	FALSE	0
1427	47400	1997	1970	0	-181.20	0	FALSE	0
1428	47400	1998	1970	0	-914.90	0	FALSE	0
1429	47400	1999	1970	0	-594.40	0	FALSE	0
1430	47400	2000	1970	0	-262.60	0	FALSE	0

1431	47400	2001	1970	0	-223.30	0	FALSE	0
1432	47400	2002	1970	0	-485.70	0	FALSE	0
1433	47400	2003	1970	0	-37.90	0	FALSE	0
1434	47400	2003	1970	0	-37.90	0	FALSE	0
1435	47400	2003	1970	0	-52,120.60	0	FALSE	0
1436	47400	2004	1970	0	-87.10	0	FALSE	0
1437	47400	2008	1970	0	-972.00	0	FALSE	0
1438	47400	2011	1970	0	-360.00	0	FALSE	0
1439	47400	2011	1970	8	27,008.59	0	FALSE	0
1440	47400	1973	1971	0	-404.00	0	FALSE	0
1441	47400	1976	1971	0	-45.00	0	FALSE	0
1442	47400	1979	1971	0	-90.00	0	FALSE	0
1443	47400	1983	1971	0	-1,101.00	0	FALSE	0
1444	47400	1986	1971	0	-25.00	0	FALSE	0
1445	47400	1991	1971	0	-218.50	0	FALSE	0
1446	47400	1992	1971	0	-3.20	0	FALSE	0
1447	47400	1993	1971	0	-684.90	0	FALSE	0
1448	47400	1995	1971	0	-10.40	0	FALSE	0
1449	47400	1997	1971	0	-405.90	0	FALSE	0
1450	47400	2002	1971	0	-19.10	0	FALSE	0
1451	47400	2003	1971	0	-131.10	0	FALSE	0
1452	47400	2003	1971	0	-128.10	0	FALSE	0
1453	47400	2003	1971	0	-11.40	0	FALSE	0
1454	47400	2006	1971	0	-57.00	0	FALSE	0
1455	47400	2008	1971	0	-23.00	0	FALSE	0
1456	47400	2011	1971	0	-108.00	0	FALSE	0
1457	47400	2011	1971	8	18,964.86	0	FALSE	0
1458	47400	1977	1972	0	-46.00	0	FALSE	0
1459	47400	1979	1972	0	-28.00	0	FALSE	0
1460	47400	1980	1972	0	-110.00	0	FALSE	0
1461	47400	1983	1972	0	-621.00	0	FALSE	0
1462	47400	1984	1972	0	-69.00	0	FALSE	0
1463	47400	1991	1972	0	-0.90	0	FALSE	0
1464	47400	1992	1972	0	-2,071.40	0	FALSE	0
1465	47400	1993	1972	0	-730.40	0	FALSE	0
1466	47400	1994	1972	0	-56.40	0	FALSE	0
1467	47400	2003	1972	0	-545.70	0	FALSE	0
1468	47400	2008	1972	0	-141.00	0	FALSE	0
1469	47400	2010	1972	0	-381.00	0	FALSE	0
1470	47400	2011	1972	8	109,788.05	0	FALSE	0
1471	47400	1978	1973	0	-110.00	0	FALSE	0
1472	47400	1979	1973	0	-57.00	0	FALSE	0
1473	47400	1983	1973	0	-24.00	0	FALSE	0
1474	47400	1984	1973	0	-1,296.00	0	FALSE	0
1475	47400	1986	1973	0	-623.00	0	FALSE	0
1476	47400	1992	1973	0	-1,703.50	0	FALSE	0
1477	47400	1993	1973	0	-405.80	0	FALSE	0
1478	47400	1994	1973	0	-221.80	0	FALSE	0
1479	47400	2010	1973	0	-12.00	0	FALSE	0
1480	47400	2011	1973	8	108,551.49	0	FALSE	0
1481	47400	1978	1974	0	-497.00	0	FALSE	0
1482	47400	1981	1974	0	-246.00	0	FALSE	0
1483	47400	1992	1974	0	-30.60	0	FALSE	0

1484	47400	1993	1974	0	-780.80	0	FALSE	0
1485	47400	1994	1974	0	-379.80	0	FALSE	0
1486	47400	1998	1974	0	-7.00	0	FALSE	0
1487	47400	2000	1974	0	-394.50	0	FALSE	0
1488	47400	2009	1974	0	-208.00	0	FALSE	0
1489	47400	2010	1974	0	-456.50	0	FALSE	0
1490	47400	2011	1974	8	57,051.46	0	FALSE	0
1491	47400	1978	1975	0	-276.00	0	FALSE	0
1492	47400	1979	1975	0	-39.00	0	FALSE	0
1493	47400	1981	1975	0	-528.00	0	FALSE	0
1494	47400	1982	1975	0	-270.00	0	FALSE	0
1495	47400	1983	1975	0	-71.00	0	FALSE	0
1496	47400	1984	1975	0	-138.00	0	FALSE	0
1497	47400	1986	1975	0	-193.00	0	FALSE	0
1498	47400	1991	1975	0	-14.50	0	FALSE	0
1499	47400	1992	1975	0	-978.30	0	FALSE	0
1500	47400	1993	1975	0	-357.10	0	FALSE	0
1501	47400	1994	1975	0	-72.30	0	FALSE	0
1502	47400	1995	1975	0	-25.00	0	FALSE	0
1503	47400	1997	1975	0	-242.40	0	FALSE	0
1504	47400	1998	1975	0	-1,019.00	0	FALSE	0
1505	47400	1999	1975	0	-316.30	0	FALSE	0
1506	47400	2000	1975	0	-629.30	0	FALSE	0
1507	47400	2001	1975	0	-453.30	0	FALSE	0
1508	47400	2002	1975	0	-283.30	0	FALSE	0
1509	47400	2004	1975	0	-219.80	0	FALSE	0
1510	47400	2005	1975	0	-99.00	0	FALSE	0
1511	47400	2006	1975	0	-31.00	0	FALSE	0
1512	47400	2009	1975	0	-7.00	0	FALSE	0
1513	47400	2010	1975	0	-434.00	0	FALSE	0
1514	47400	2011	1975	0	-682.00	0	FALSE	0
1515	47400	2011	1975	8	144,638.16	0	FALSE	0
1516	47400	1978	1976	0	-43.00	0	FALSE	0
1517	47400	1979	1976	0	-41.00	0	FALSE	0
1518	47400	1981	1976	0	-117.00	0	FALSE	0
1519	47400	1982	1976	0	-18.00	0	FALSE	0
1520	47400	1985	1976	0	-42.00	0	FALSE	0
1521	47400	1986	1976	0	-2.00	0	FALSE	0
1522	47400	1986	1976	0	-33.00	0	FALSE	0
1523	47400	1987	1976	0	-53.00	0	FALSE	0
1524	47400	1988	1976	4	108.68	1976	FALSE	0
1525	47400	1989	1976	0	-289.00	0	FALSE	0
1526	47400	1992	1976	0	-290.80	0	FALSE	0
1527	47400	1993	1976	0	-308.90	0	FALSE	0
1528	47400	1994	1976	0	-55.50	0	FALSE	0
1529	47400	1995	1976	0	-257.90	0	FALSE	0
1530	47400	1997	1976	0	-29.00	0	FALSE	0
1531	47400	1999	1976	0	-92.60	0	FALSE	0
1532	47400	2000	1976	0	-1,835.70	0	FALSE	0
1533	47400	2005	1976	0	-7.00	0	FALSE	0
1534	47400	2007	1976	0	-132.20	0	FALSE	0
1535	47400	2010	1976	0	-334.20	0	FALSE	0
1536	47400	2011	1976	8	106,854.96	0	FALSE	0

1537	47400	1978	1977	0	-763.00	0	FALSE	0
1538	47400	1979	1977	0	-49.00	0	FALSE	0
1539	47400	1981	1977	0	-39.00	0	FALSE	0
1540	47400	1982	1977	0	-80.00	0	FALSE	0
1541	47400	1983	1977	0	-146.00	0	FALSE	0
1542	47400	1984	1977	0	-91.00	0	FALSE	0
1543	47400	1985	1977	0	-576.00	0	FALSE	0
1544	47400	1986	1977	0	-344.00	0	FALSE	0
1545	47400	1987	1977	0	-81.00	0	FALSE	0
1546	47400	1989	1977	0	0.00	0	FALSE	0
1547	47400	1990	1977	0	-1.70	0	FALSE	0
1548	47400	1991	1977	0	-215.00	0	FALSE	0
1549	47400	1992	1977	0	-81.40	0	FALSE	0
1550	47400	1993	1977	0	-110.60	0	FALSE	0
1551	47400	1994	1977	0	-8.40	0	FALSE	0
1552	47400	1998	1977	0	-221.20	0	FALSE	0
1553	47400	2002	1977	0	-143.30	0	FALSE	0
1554	47400	2003	1977	0	-18.90	0	FALSE	0
1555	47400	2010	1977	0	-2,108.30	0	FALSE	0
1556	47400	2011	1977	8	145,040.78	0	FALSE	0
1557	47400	1979	1978	0	-16.00	0	FALSE	0
1558	47400	1981	1978	0	-198.00	0	FALSE	0
1559	47400	1982	1978	0	-40.00	0	FALSE	0
1560	47400	1983	1978	0	-94.00	0	FALSE	0
1561	47400	1984	1978	0	-28.00	0	FALSE	0
1562	47400	1985	1978	0	-475.00	0	FALSE	0
1563	47400	1986	1978	0	-65.00	0	FALSE	0
1564	47400	1987	1978	0	-2,100.00	0	FALSE	0
1565	47400	1988	1978	0	-3,402.30	0	FALSE	0
1566	47400	1989	1978	0	-1,328.00	0	FALSE	0
1567	47400	1995	1978	0	-104.10	0	FALSE	0
1568	47400	1996	1978	0	-325.60	0	FALSE	0
1569	47400	1997	1978	0	-19.00	0	FALSE	0
1570	47400	2000	1978	0	-207.90	0	FALSE	0
1571	47400	2002	1978	0	-12.90	0	FALSE	0
1572	47400	2005	1978	0	-8.00	0	FALSE	0
1573	47400	2010	1978	0	-2,342.00	0	FALSE	0
1574	47400	2011	1978	8	93,920.92	0	FALSE	0
1575	47400	1980	1979	0	-3.00	0	FALSE	0
1576	47400	1983	1979	0	-590.00	0	FALSE	0
1577	47400	1984	1979	0	-582.00	0	FALSE	0
1578	47400	1985	1979	0	-42.00	0	FALSE	0
1579	47400	1986	1979	0	-188.00	0	FALSE	0
1580	47400	1987	1979	0	-176.00	0	FALSE	0
1581	47400	1988	1979	0	-276.00	0	FALSE	0
1582	47400	1989	1979	0	-595.00	0	FALSE	0
1583	47400	1990	1979	0	-23.10	0	FALSE	0
1584	47400	1991	1979	4	244.71	1979	FALSE	0
1585	47400	1992	1979	0	-508.60	0	FALSE	0
1586	47400	1994	1979	0	-28.70	0	FALSE	0
1587	47400	2001	1979	0	-425.20	0	FALSE	0
1588	47400	2003	1979	0	-166.50	0	FALSE	0
1589	47400	2008	1979	0	-282.00	0	FALSE	0

1590	47400	2011	1979	8	77,160.47	0	FALSE	0
1591	47400	1985	1980	0	-230.00	0	FALSE	0
1592	47400	1986	1980	0	-41.00	0	FALSE	0
1593	47400	1987	1980	0	-112.00	0	FALSE	0
1594	47400	1988	1980	0	-13.00	0	FALSE	0
1595	47400	1989	1980	0	0.00	0	FALSE	0
1596	47400	1992	1980	0	-62.00	0	FALSE	0
1597	47400	1995	1980	0	-442.00	0	FALSE	0
1598	47400	1996	1980	0	-4,665.40	0	FALSE	0
1599	47400	1997	1980	0	-4,412.20	0	FALSE	0
1600	47400	1998	1980	0	-865.70	0	FALSE	0
1601	47400	1999	1980	0	-3,443.00	0	FALSE	0
1602	47400	2000	1980	0	-2,812.00	0	FALSE	0
1603	47400	2001	1980	0	-3,490.30	0	FALSE	0
1604	47400	2002	1980	0	-804.60	0	FALSE	0
1605	47400	2003	1980	0	-36.60	0	FALSE	0
1606	47400	2003	1980	0	-373.70	0	FALSE	0
1607	47400	2005	1980	0	-1,336.00	0	FALSE	0
1608	47400	2011	1980	0	-920.00	0	FALSE	0
1609	47400	2011	1980	8	122,191.66	0	FALSE	0
1610	47400	1986	1981	0	-3,085.00	0	FALSE	0
1611	47400	1987	1981	0	-192.00	0	FALSE	0
1612	47400	1988	1981	0	-2,418.00	0	FALSE	0
1613	47400	1989	1981	0	-328.00	0	FALSE	0
1614	47400	1990	1981	0	-4,946.70	0	FALSE	0
1615	47400	1991	1981	0	-111.30	0	FALSE	0
1616	47400	1992	1981	0	-150.20	0	FALSE	0
1617	47400	1995	1981	0	-18.10	0	FALSE	0
1618	47400	1996	1981	0	-261.60	0	FALSE	0
1619	47400	1997	1981	0	-1,792.80	0	FALSE	0
1620	47400	1998	1981	0	-27.00	0	FALSE	0
1621	47400	2000	1981	0	-5,311.00	0	FALSE	0
1622	47400	2001	1981	0	-7.90	0	FALSE	0
1623	47400	2002	1981	0	-176.90	0	FALSE	0
1624	47400	2003	1981	0	-73.40	0	FALSE	0
1625	47400	2003	1981	0	-79.90	0	FALSE	0
1626	47400	2008	1981	0	-4,230.00	0	FALSE	0
1627	47400	2009	1981	0	-13.00	0	FALSE	0
1628	47400	2011	1981	8	87,840.47	0	FALSE	0
1629	47400	1983	1982	0	-492.00	0	FALSE	0
1630	47400	1984	1982	0	-278.00	0	FALSE	0
1631	47400	1987	1982	0	-962.00	0	FALSE	0
1632	47400	1988	1982	0	-665.00	0	FALSE	0
1633	47400	1989	1982	0	-11,880.00	0	FALSE	0
1634	47400	1990	1982	0	-576.70	0	FALSE	0
1635	47400	1996	1982	0	-275.30	0	FALSE	0
1636	47400	1997	1982	0	-342.80	0	FALSE	0
1637	47400	1998	1982	0	-211.50	0	FALSE	0
1638	47400	2001	1982	0	-1,295.60	0	FALSE	0
1639	47400	2002	1982	0	-253.20	0	FALSE	0
1640	47400	2003	1982	0	-629.00	0	FALSE	0
1641	47400	2003	1982	0	-30.10	0	FALSE	0
1642	47400	2008	1982	0	-425.00	0	FALSE	0

1643	47400	2011	1982	8	209,885.33	0	FALSE	0
1644	47400	1986	1983	0	-1,367.00	0	FALSE	0
1645	47400	1987	1983	0	-2,433.00	0	FALSE	0
1646	47400	1988	1983	0	-264.00	0	FALSE	0
1647	47400	1989	1983	0	-534.00	0	FALSE	0
1648	47400	1990	1983	0	-4,810.80	0	FALSE	0
1649	47400	1991	1983	0	-1,137.80	0	FALSE	0
1650	47400	1997	1983	0	-491.10	0	FALSE	0
1651	47400	1998	1983	0	-8.80	0	FALSE	0
1652	47400	2001	1983	0	-8.80	0	FALSE	0
1653	47400	2002	1983	0	-15.40	0	FALSE	0
1654	47400	2011	1983	8	132,046.38	0	FALSE	0
1655	47400	1987	1984	0	-28.00	0	FALSE	0
1656	47400	1988	1984	0	-1,642.00	0	FALSE	0
1657	47400	1989	1984	0	-2,802.00	0	FALSE	0
1658	47400	1990	1984	0	-4,182.40	0	FALSE	0
1659	47400	1991	1984	0	-1,154.80	0	FALSE	0
1660	47400	1994	1984	0	-181.70	0	FALSE	0
1661	47400	1997	1984	0	-376.80	0	FALSE	0
1662	47400	1998	1984	0	-15.80	0	FALSE	0
1663	47400	1999	1984	0	-1,502.30	0	FALSE	0
1664	47400	2000	1984	0	-337.10	0	FALSE	0
1665	47400	2001	1984	0	-9.20	0	FALSE	0
1666	47400	2002	1984	0	-46.60	0	FALSE	0
1667	47400	2003	1984	0	-92.90	0	FALSE	0
1668	47400	2003	1984	0	-9.20	0	FALSE	0
1669	47400	2003	1984	0	-205.60	0	FALSE	0
1670	47400	2003	1984	0	-131.40	0	FALSE	0
1671	47400	2003	1984	0	-9.20	0	FALSE	0
1672	47400	2003	1984	0	-9.20	0	FALSE	0
1673	47400	2003	1984	0	-9.20	0	FALSE	0
1674	47400	2003	1984	0	-9.20	0	FALSE	0
1675	47400	2003	1984	0	-9.20	0	FALSE	0
1676	47400	2003	1984	0	-9.20	0	FALSE	0
1677	47400	2003	1984	0	-9.20	0	FALSE	0
1678	47400	2003	1984	0	-9.20	0	FALSE	0
1679	47400	2003	1984	0	-9.20	0	FALSE	0
1680	47400	2003	1984	0	-9.20	0	FALSE	0
1681	47400	2003	1984	0	-9.20	0	FALSE	0
1682	47400	2003	1984	0	-9.20	0	FALSE	0
1683	47400	2004	1984	0	-9.20	0	FALSE	0
1684	47400	2008	1984	0	-118.00	0	FALSE	0
1685	47400	2010	1984	0	-3,599.50	0	FALSE	0
1686	47400	2011	1984	8	121,892.29	0	FALSE	0
1687	47400	1989	1985	0	-557.00	0	FALSE	0
1688	47400	1990	1985	0	-1,254.00	0	FALSE	0
1689	47400	1995	1985	0	-521.80	0	FALSE	0
1690	47400	1996	1985	0	-182.60	0	FALSE	0
1691	47400	1997	1985	0	-1,948.30	0	FALSE	0
1692	47400	1998	1985	0	-786.40	0	FALSE	0
1693	47400	1999	1985	0	-589.50	0	FALSE	0
1694	47400	2000	1985	0	-460.00	0	FALSE	0
1695	47400	2001	1985	0	-41.40	0	FALSE	0

1696	47400	2002	1985	0	-338.70	0	FALSE	0
1697	47400	2003	1985	0	-12.30	0	FALSE	0
1698	47400	2003	1985	0	-39.90	0	FALSE	0
1699	47400	2003	1985	0	-164.10	0	FALSE	0
1700	47400	2003	1985	0	-1,441.00	0	FALSE	0
1701	47400	2004	1985	0	-9.60	0	FALSE	0
1702	47400	2005	1985	0	-405.00	0	FALSE	0
1703	47400	2010	1985	0	-885.90	0	FALSE	0
1704	47400	2011	1985	0	-242.10	0	FALSE	0
1705	47400	2011	1985	8	677,899.61	0	FALSE	0
1706	47400	1987	1986	0	-43.00	0	FALSE	0
1707	47400	1988	1986	0	-167.00	0	FALSE	0
1708	47400	1989	1986	0	-209.00	0	FALSE	0
1709	47400	1995	1986	0	-222.40	0	FALSE	0
1710	47400	1997	1986	0	-116.00	0	FALSE	0
1711	47400	1998	1986	0	-169.00	0	FALSE	0
1712	47400	1999	1986	0	-50.00	0	FALSE	0
1713	47400	2004	1986	0	-137.10	0	FALSE	0
1714	47400	2011	1986	8	136,683.35	0	FALSE	0
1715	47400	1988	1987	0	-37.00	0	FALSE	0
1716	47400	1990	1987	0	-26.20	0	FALSE	0
1717	47400	1996	1987	0	-7.20	0	FALSE	0
1718	47400	1997	1987	0	-425.90	0	FALSE	0
1719	47400	1999	1987	0	-26.00	0	FALSE	0
1720	47400	2000	1987	0	-372.80	0	FALSE	0
1721	47400	2001	1987	0	-42.10	0	FALSE	0
1722	47400	2002	1987	0	-192.60	0	FALSE	0
1723	47400	2003	1987	0	-10.30	0	FALSE	0
1724	47400	2003	1987	0	-216.70	0	FALSE	0
1725	47400	2003	1987	0	-106.00	0	FALSE	0
1726	47400	2011	1987	8	328,625.90	0	FALSE	0
1727	47400	1990	1988	0	-2.30	0	FALSE	0
1728	47400	1991	1988	0	-275.00	0	FALSE	0
1729	47400	1996	1988	0	-241.70	0	FALSE	0
1730	47400	1997	1988	0	-418.20	0	FALSE	0
1731	47400	1998	1988	0	-554.90	0	FALSE	0
1732	47400	1999	1988	0	-564.20	0	FALSE	0
1733	47400	2000	1988	0	-275.00	0	FALSE	0
1734	47400	2001	1988	0	-430.20	0	FALSE	0
1735	47400	2002	1988	0	-46.10	0	FALSE	0
1736	47400	2003	1988	0	-10.80	0	FALSE	0
1737	47400	2003	1988	0	-129.20	0	FALSE	0
1738	47400	2004	1988	0	-10.80	0	FALSE	0
1739	47400	2011	1988	8	239,184.34	0	FALSE	0
1740	47400	1995	1989	0	-234.20	0	FALSE	0
1741	47400	1996	1989	0	-334.70	0	FALSE	0
1742	47400	1997	1989	0	-216.50	0	FALSE	0
1743	47400	1998	1989	0	-573.90	0	FALSE	0
1744	47400	1999	1989	0	-540.80	0	FALSE	0
1745	47400	2009	1989	0	-69.00	0	FALSE	0
1746	47400	2011	1989	8	332,701.42	0	FALSE	0
1747	47400	1995	1990	0	-259.30	0	FALSE	0
1748	47400	1996	1990	0	-169.30	0	FALSE	0

1749	47400	1997	1990	0	-378.50	0	FALSE	0
1750	47400	1998	1990	0	-572.20	0	FALSE	0
1751	47400	1999	1990	0	-3,484.50	0	FALSE	0
1752	47400	2000	1990	0	-1,139.40	0	FALSE	0
1753	47400	2001	1990	0	-323.70	0	FALSE	0
1754	47400	2002	1990	0	-1,194.30	0	FALSE	0
1755	47400	2003	1990	0	-74.60	0	FALSE	0
1756	47400	2003	1990	0	-438.90	0	FALSE	0
1757	47400	2004	1990	0	-35.30	0	FALSE	0
1758	47400	2008	1990	0	-31.00	0	FALSE	0
1759	47400	2011	1990	8	680,637.85	0	FALSE	0
1760	47400	1998	1991	0	-72.00	0	FALSE	0
1761	47400	1999	1991	0	-22.20	0	FALSE	0
1762	47400	2002	1991	0	-11.10	0	FALSE	0
1763	47400	2004	1991	0	-60.90	0	FALSE	0
1764	47400	2011	1991	8	519,771.93	0	FALSE	0
1765	47400	1993	1992	4	7,230.67	1992	FALSE	0
1766	47400	1995	1992	0	-335.40	0	FALSE	0
1767	47400	1997	1992	0	-6,338.90	0	FALSE	0
1768	47400	1998	1992	0	-230.30	0	FALSE	0
1769	47400	2000	1992	0	-22.00	0	FALSE	0
1770	47400	2002	1992	0	-33.00	0	FALSE	0
1771	47400	2003	1992	0	-481.00	0	FALSE	0
1772	47400	2003	1992	0	-56.10	0	FALSE	0
1773	47400	2004	1992	0	-389.50	0	FALSE	0
1774	47400	2011	1992	8	486,666.63	0	FALSE	0
1775	47400	1994	1993	0	-60.00	0	FALSE	0
1776	47400	1994	1993	4	62,172.08	1993	FALSE	0
1777	47400	1995	1993	0	-475.80	0	FALSE	0
1778	47400	1996	1993	0	-29.30	0	FALSE	0
1779	47400	1997	1993	0	-237.90	0	FALSE	0
1780	47400	2002	1993	0	-237.90	0	FALSE	0
1781	47400	2008	1993	0	-31,464.90	0	FALSE	0
1782	47400	2011	1993	8	792,959.72	0	FALSE	0
1783	47400	1994	1994	3	-1,056.60	1994	FALSE	0
1784	47400	1995	1994	0	-584.50	0	FALSE	0
1785	47400	1996	1994	0	-326.90	0	FALSE	0
1786	47400	1997	1994	0	-738.70	0	FALSE	0
1787	47400	1998	1994	0	-22.00	0	FALSE	0
1788	47400	1999	1994	0	-253.50	0	FALSE	0
1789	47400	2002	1994	0	-293.50	0	FALSE	0
1790	47400	2004	1994	0	-11.00	0	FALSE	0
1791	47400	2011	1994	8	463,654.51	0	FALSE	0
1792	47400	1996	1995	0	-778.70	0	FALSE	0
1793	47400	1998	1995	0	-1,202.60	0	FALSE	0
1794	47400	2000	1995	0	-11.00	0	FALSE	0
1795	47400	2001	1995	0	-59.70	0	FALSE	0
1796	47400	2002	1995	0	-480.90	0	FALSE	0
1797	47400	2003	1995	0	-27.30	0	FALSE	0
1798	47400	2003	1995	0	-93.00	0	FALSE	0
1799	47400	2004	1995	0	-11.10	0	FALSE	0
1800	47400	2005	1995	0	-155.00	0	FALSE	0
1801	47400	2011	1995	0	-115.00	0	FALSE	0

1802	47400	2011	1995	8	357,845.36	0		FALSE	0
1803	47400	1996	1996	3	-336.20	0		FALSE	0
1804	47400	1997	1996	4	276,168.72	1996		FALSE	0
1805	47400	1998	1996	0	-307.10	0		FALSE	0
1806	47400	1999	1996	0	-241.00	0		FALSE	0
1807	47400	2003	1996	0	-39.80	0		FALSE	0
1808	47400	2008	1996	0	-184.00	0		FALSE	0
1809	47400	2011	1996	8	560,475.87	0		FALSE	0
1810	47400	1997	1997	4	14,132.34	1997		FALSE	0
1811	47400	1998	1997	0	-605.00	0		FALSE	0
1812	47400	1999	1997	0	-216.20	0		FALSE	0
1813	47400	2000	1997	0	-373.40	0		FALSE	0
1814	47400	2001	1997	0	-10.90	0		FALSE	0
1815	47400	2002	1997	0	-237.80	0		FALSE	0
1816	47400	2003	1997	0	-237.80	0		FALSE	0
1817	47400	2004	1997	0	-237.80	0		FALSE	0
1818	47400	2011	1997	8	521,699.29	0		FALSE	0
1819	47400	2001	1998	0	-616.50	0		FALSE	0
1820	47400	2002	1998	0	-44.20	0		FALSE	0
1821	47400	2004	1998	0	-33.40	0		FALSE	0
1822	47400	2011	1998	8	410,383.42	0		FALSE	0
1823	47400	2001	1999	0	-571.10	0		FALSE	0
1824	47400	2002	1999	0	-257.20	0		FALSE	0
1825	47400	2003	1999	0	-11.40	0		FALSE	0
1826	47400	2003	1999	0	-245.80	0		FALSE	0
1827	47400	2003	1999	0	-11.40	0		FALSE	0
1828	47400	2003	1999	0	-246.50	0		FALSE	0
1829	47400	2010	1999	0	-462.00	0		FALSE	0
1830	47400	2011	1999	8	410,977.25	0		FALSE	0
1831	47400	2001	2000	0	-291.00	0		FALSE	0
1832	47400	2001	2000	3	-1,826.80	2000		FALSE	0
1833	47400	2002	2000	0	-714.70	0		FALSE	0
1834	47400	2006	2000	0	-801.00	0		FALSE	0
1835	47400	2009	2000	0	-84.00	0		FALSE	0
1836	47400	2011	2000	8	479,332.56	0		FALSE	0
1837	47400	2002	2001	0	-602.40	0		FALSE	0
1838	47400	2003	2001	0	-261.10	0		FALSE	0
1839	47400	2003	2001	0	-261.10	0		FALSE	0
1840	47400	2004	2001	0	-261.10	0		FALSE	0
1841	47400	2011	2001	8	472,747.67	0		FALSE	0
1842	47400	2002	2002	0	-398.80	0		FALSE	0
1843	47400	2003	2002	0	-103.50	0		FALSE	0
1844	47400	2003	2002	0	-46.00	0		FALSE	0
1845	47400	2004	2002	0	-1,647.40	0		FALSE	0
1846	47400	2011	2002	8	511,085.75	0		FALSE	0
1847	47400	2011	2003	8	423,598.69	0		FALSE	0
1848	47400	2011	2004	8	778,010.48	0		FALSE	0
1849	47400	2008	2005	3	-497.40	2005		FALSE	0
1850	47400	2011	2005	8	793,470.21	0		FALSE	0
1851	47400	2008	2006	4	82.29	2006		FALSE	0
1852	47400	2009	2006	4	1,793.46	0		FALSE	0
1853	47400	2011	2006	8	1,160,619.99	0		FALSE	0
1854	47400	2008	2007	4	74,086.72	2007		FALSE	0

1855	47400	2009	2007	4	7,112.35	0	FALSE	0
1856	47400	2010	2007	3	-2,409.30	0	FALSE	0
1857	47400	2011	2007	3	-8.80	2007	FALSE	0
1858	47400	2011	2007	8	1,581,317.34	0	FALSE	0
1859	47400	2009	2008	4	20,248.96	0	FALSE	0
1860	47400	2010	2008	0	-1,242.70	0	FALSE	0
1861	47400	2010	2008	3	-1,578.00	0	FALSE	0
1862	47400	2011	2008	4	0.00	2008	FALSE	0
1863	47400	2011	2008	8	1,517,742.62	0	FALSE	0
1864	47400	2010	2009	4	15,697.30	0	FALSE	0
1865	47400	2011	2009	4	1,264.81	2009	FALSE	0
1866	47400	2011	2009	8	942,790.65	0	FALSE	0
1867	47400	2011	2010	4	99,976.46	2010	FALSE	0
1868	47400	2011	2010	8	1,356,461.25	0	FALSE	0
1869	47400	2011	2011	8	1,583,225.80	0	FALSE	0
1870	47410	1962	1945	0	-43.00	0	FALSE	0
1871	47410	1980	1945	0	-732.00	0	FALSE	0
1872	47410	1991	1945	0	-32.00	0	FALSE	0
1873	47410	2011	1945	0	-22.00	0	FALSE	0
1874	47410	2011	1945	8	2,203.16	0	FALSE	0
1875	47410	1962	1946	0	-6.00	0	FALSE	0
1876	47410	2011	1946	8	414.58	0	FALSE	0
1877	47410	1962	1947	0	-8.00	0	FALSE	0
1878	47410	2011	1947	8	476.35	0	FALSE	0
1879	47410	1962	1948	0	-9.00	0	FALSE	0
1880	47410	2011	1948	8	569.49	0	FALSE	0
1881	47410	1962	1949	0	-10.00	0	FALSE	0
1882	47410	2011	1949	8	673.48	0	FALSE	0
1883	47410	1962	1950	0	-11.00	0	FALSE	0
1884	47410	2011	1950	8	808.02	0	FALSE	0
1885	47410	1962	1951	0	-13.00	0	FALSE	0
1886	47410	2011	1951	8	900.65	0	FALSE	0
1887	47410	1962	1952	0	-20.00	0	FALSE	0
1888	47410	2011	1952	8	1,366.00	0	FALSE	0
1889	47410	1962	1953	0	-37.00	0	FALSE	0
1890	47410	2011	1953	8	2,459.00	0	FALSE	0
1891	47410	1962	1954	0	-47.00	0	FALSE	0
1892	47410	2011	1954	8	3,197.00	0	FALSE	0
1893	47410	1962	1955	0	-21.00	0	FALSE	0
1894	47410	1963	1955	0	-19.00	0	FALSE	0
1895	47410	2011	1955	8	2,771.00	0	FALSE	0
1896	47410	1963	1956	0	-49.00	0	FALSE	0
1897	47410	2011	1956	8	3,325.00	0	FALSE	0
1898	47410	1963	1957	0	-4.00	0	FALSE	0
1899	47410	1965	1957	0	-55.00	0	FALSE	0
1900	47410	1978	1957	0	-35.00	0	FALSE	0
1901	47410	1979	1957	0	-34.00	0	FALSE	0
1902	47410	1980	1957	0	-329.00	0	FALSE	0
1903	47410	2011	1957	8	3,592.00	0	FALSE	0
1904	47410	2011	1958	8	1,170.00	0	FALSE	0
1905	47410	1965	1959	0	-527.00	0	FALSE	0
1906	47410	1966	1959	0	-648.00	0	FALSE	0
1907	47410	1967	1959	0	-369.00	0	FALSE	0

1908	47410	1968	1959	0	-28.00	0	FALSE	0
1909	47410	2011	1959	8	1,533.00	0	FALSE	0
1910	47410	1970	1960	0	-144.00	0	FALSE	0
1911	47410	1973	1960	0	-600.00	0	FALSE	0
1912	47410	2011	1960	8	1,560.00	0	FALSE	0
1913	47410	1965	1961	0	-23.00	0	FALSE	0
1914	47410	1972	1961	0	-171.00	0	FALSE	0
1915	47410	1973	1961	0	-79.00	0	FALSE	0
1916	47410	2011	1961	0	-296.20	0	FALSE	0
1917	47410	2011	1961	8	1,791.78	0	FALSE	0
1918	47410	1963	1962	0	-13.00	0	FALSE	0
1919	47410	1969	1962	0	-56.00	0	FALSE	0
1920	47410	1972	1962	0	-72.00	0	FALSE	0
1921	47410	1973	1962	0	-38.00	0	FALSE	0
1922	47410	2011	1962	8	5,328.00	0	FALSE	0
1923	47410	1972	1963	0	-50.00	0	FALSE	0
1924	47410	1977	1963	0	-1,223.00	0	FALSE	0
1925	47410	1978	1963	0	-500.00	0	FALSE	0
1926	47410	1979	1963	0	-259.00	0	FALSE	0
1927	47410	1981	1963	0	-554.00	0	FALSE	0
1928	47410	1982	1963	0	-963.00	0	FALSE	0
1929	47410	1983	1963	0	-78.00	0	FALSE	0
1930	47410	1984	1963	0	-130.00	0	FALSE	0
1931	47410	2011	1963	8	2,524.00	0	FALSE	0
1932	47410	2011	1964	8	4,560.00	0	FALSE	0
1933	47410	2011	1965	8	3,229.00	0	FALSE	0
1934	47410	1985	1966	0	-130.00	0	FALSE	0
1935	47410	1986	1966	0	-286.00	0	FALSE	0
1936	47410	2011	1966	8	4,597.36	0	FALSE	0
1937	47410	2011	1967	8	7,481.00	0	FALSE	0
1938	47410	1983	1968	0	-261.00	0	FALSE	0
1939	47410	2011	1968	8	8,000.00	0	FALSE	0
1940	47410	2010	1969	0	-25.50	0	FALSE	0
1941	47410	2011	1969	8	7,521.50	0	FALSE	0
1942	47410	2010	1970	0	-2,107.90	0	FALSE	0
1943	47410	2011	1970	8	11,754.13	0	FALSE	0
1944	47410	2010	1971	0	-160.90	0	FALSE	0
1945	47410	2011	1971	0	-30.20	0	FALSE	0
1946	47410	2011	1971	8	12,073.93	0	FALSE	0
1947	47410	1980	1972	0	-247.00	0	FALSE	0
1948	47410	2010	1972	0	-118.00	0	FALSE	0
1949	47410	2011	1972	8	12,957.01	0	FALSE	0
1950	47410	2010	1973	0	-281.10	0	FALSE	0
1951	47410	2011	1973	0	-26.00	0	FALSE	0
1952	47410	2011	1973	8	14,692.86	0	FALSE	0
1953	47410	2008	1974	0	-16.00	0	FALSE	0
1954	47410	2011	1974	8	20,167.00	0	FALSE	0
1955	47410	2010	1975	0	-115.80	0	FALSE	0
1956	47410	2011	1975	8	34,619.23	0	FALSE	0
1957	47410	2010	1976	0	-522.30	0	FALSE	0
1958	47410	2011	1976	0	-48.50	0	FALSE	0
1959	47410	2011	1976	8	37,678.27	0	FALSE	0
1960	47410	2011	1977	0	-172.70	0	FALSE	0

1961	47410	2011	1977	8	42,422.26	0	FALSE	0
1962	47410	2010	1978	0	-2,795.70	0	FALSE	0
1963	47410	2011	1978	0	-195.30	0	FALSE	0
1964	47410	2011	1978	8	62,182.03	0	FALSE	0
1965	47410	2011	1979	0	-402.20	0	FALSE	0
1966	47410	2011	1979	8	52,049.79	0	FALSE	0
1967	47410	2011	1980	0	-212.50	0	FALSE	0
1968	47410	2011	1980	8	43,273.51	0	FALSE	0
1969	47410	2011	1981	0	-236.60	0	FALSE	0
1970	47410	2011	1981	8	53,231.36	0	FALSE	0
1971	47410	2011	1982	0	-645.00	0	FALSE	0
1972	47410	2011	1982	8	30,980.05	0	FALSE	0
1973	47410	2011	1983	0	-106.60	0	FALSE	0
1974	47410	2011	1983	8	40,503.38	0	FALSE	0
1975	47410	2011	1984	0	-180.30	0	FALSE	0
1976	47410	2011	1984	8	40,236.69	0	FALSE	0
1977	47410	2011	1985	0	-1,040.20	0	FALSE	0
1978	47410	2011	1985	8	32,685.06	0	FALSE	0
1979	47410	2011	1986	0	-256.10	0	FALSE	0
1980	47410	2011	1986	8	51,608.88	0	FALSE	0
1981	47410	2011	1987	0	-235.40	0	FALSE	0
1982	47410	2011	1987	8	67,879.82	0	FALSE	0
1983	47410	2010	1988	0	-3,245.70	0	FALSE	0
1984	47410	2011	1988	0	-677.40	0	FALSE	0
1985	47410	2011	1988	8	66,613.00	0	FALSE	0
1986	47410	2010	1989	0	-2,881.20	0	FALSE	0
1987	47410	2011	1989	0	-77.60	0	FALSE	0
1988	47410	2011	1989	8	81,267.48	0	FALSE	0
1989	47410	2010	1990	0	-8,254.30	0	FALSE	0
1990	47410	2011	1990	0	-227.30	0	FALSE	0
1991	47410	2011	1990	8	89,672.48	0	FALSE	0
1992	47410	2010	1991	0	-5,467.50	0	FALSE	0
1993	47410	2011	1991	0	-1,061.90	0	FALSE	0
1994	47410	2011	1991	8	108,151.36	0	FALSE	0
1995	47410	2010	1992	0	-5,931.20	0	FALSE	0
1996	47410	2011	1992	0	-286.30	0	FALSE	0
1997	47410	2011	1992	8	163,702.21	0	FALSE	0
1998	47410	2011	1993	0	-172.10	0	FALSE	0
1999	47410	2011	1993	8	112,072.14	0	FALSE	0
2000	47410	1997	1994	3	-8,761.70	0	FALSE	0
2001	47410	2011	1994	0	-274.20	0	FALSE	0
2002	47410	2011	1994	8	64,781.32	0	FALSE	0
2003	47410	2011	1995	0	-1,074.00	0	FALSE	0
2004	47410	2011	1995	8	55,117.61	0	FALSE	0
2005	47410	2011	1997	0	-906.80	0	FALSE	0
2006	47410	2011	1997	8	45,912.56	0	FALSE	0
2007	47410	2011	1998	0	-416.40	0	FALSE	0
2008	47410	2011	1998	8	46,874.69	0	FALSE	0
2009	47410	2011	1999	0	-804.00	0	FALSE	0
2010	47410	2011	1999	8	40,693.10	0	FALSE	0
2011	47410	2010	2000	0	-4,400.30	0	FALSE	0
2012	47410	2011	2000	0	-349.70	0	FALSE	0
2013	47410	2011	2000	8	33,672.14	0	FALSE	0

2014	47410	2010	2001	0	-1,785.50	0	FALSE	0
2015	47410	2011	2001	0	-2,292.50	0	FALSE	0
2016	47410	2011	2001	8	25,583.05	0	FALSE	0
2017	47410	2010	2002	0	-815.20	0	FALSE	0
2018	47410	2011	2002	0	-1,318.80	0	FALSE	0
2019	47410	2011	2002	8	59,316.63	0	FALSE	0
2020	47410	2010	2003	0	-1,471.50	0	FALSE	0
2021	47410	2011	2003	0	-1,474.10	0	FALSE	0
2022	47410	2011	2003	8	55,673.16	0	FALSE	0
2023	47410	2010	2004	0	-3,171.30	0	FALSE	0
2024	47410	2011	2004	0	-2,191.10	0	FALSE	0
2025	47410	2011	2004	8	68,225.83	0	FALSE	0
2026	47410	2011	2005	0	-1,182.70	0	FALSE	0
2027	47410	2011	2005	8	63,429.49	0	FALSE	0
2028	47410	2009	2006	4	79.94	0	FALSE	0
2029	47410	2011	2006	0	-367.80	0	FALSE	0
2030	47410	2011	2006	8	136,065.53	0	FALSE	0
2031	47410	2008	2007	3	-416.00	2007	FALSE	0
2032	47410	2009	2007	4	3.86	0	FALSE	0
2033	47410	2010	2007	0	-743.50	0	FALSE	0
2034	47410	2010	2007	3	-24.80	0	FALSE	0
2035	47410	2011	2007	0	-338.10	0	FALSE	0
2036	47410	2011	2007	8	191,840.99	0	FALSE	0
2037	47410	2009	2008	4	653.62	0	FALSE	0
2038	47410	2010	2008	4	14.58	0	FALSE	0
2039	47410	2011	2008	0	-287.30	0	FALSE	0
2040	47410	2011	2008	8	225,262.76	0	FALSE	0
2041	47410	2010	2009	4	203.94	0	FALSE	0
2042	47410	2011	2009	0	-136.60	0	FALSE	0
2043	47410	2011	2009	4	0.08	2009	FALSE	0
2044	47410	2011	2009	8	129,908.59	0	FALSE	0
2045	47410	2011	2010	0	-196.30	0	FALSE	0
2046	47410	2011	2010	4	164.59	2010	FALSE	0
2047	47410	2011	2010	8	31,334.64	0	FALSE	0
2048	47410	2011	2011	8	221,235.12	0	FALSE	0
2049	47500	1991	1961	0	-7.00	0	FALSE	0
2050	47500	2011	1961	0	-115.20	0	FALSE	0
2051	47500	2011	1961	8	12.02	0	FALSE	0
2052	47500	1998	1969	0	-5.00	0	FALSE	0
2053	47500	1999	1969	0	-7.50	0	FALSE	0
2054	47500	2000	1969	0	-2.50	0	FALSE	0
2055	47500	2001	1969	0	-6.60	0	FALSE	0
2056	47500	2002	1969	0	-5.00	0	FALSE	0
2057	47500	2011	1969	8	1,356.35	0	FALSE	0
2058	47500	1993	1970	0	-10.70	0	FALSE	0
2059	47500	1994	1970	0	-3.20	0	FALSE	0
2060	47500	2011	1971	8	65.00	0	FALSE	0
2061	47500	1993	1972	0	-48.30	0	FALSE	0
2062	47500	1994	1972	0	-48.30	0	FALSE	0
2063	47500	1997	1972	0	-96.10	0	FALSE	0
2064	47500	2011	1972	8	14,154.38	0	FALSE	0
2065	47500	2011	1973	8	5,056.00	0	FALSE	0
2066	47500	1992	1974	0	-481.90	0	FALSE	0

2067	47500	1993	1974	0	-4.50	0	FALSE	0
2068	47500	1994	1974	0	-4.50	0	FALSE	0
2069	47500	2011	1974	8	7,373.22	0	FALSE	0
2070	47500	1985	1975	0	-57.30	0	FALSE	0
2071	47500	2000	1975	0	-564.10	0	FALSE	0
2072	47500	2001	1975	0	-3.20	0	FALSE	0
2073	47500	2004	1975	0	-13.60	0	FALSE	0
2074	47500	2011	1975	8	8,587.37	0	FALSE	0
2075	47500	2000	1976	0	-34.80	0	FALSE	0
2076	47500	2011	1976	8	66,670.57	0	FALSE	0
2077	47500	2011	1977	8	4,549.00	0	FALSE	0
2078	47500	1985	1978	0	-78.40	0	FALSE	0
2079	47500	1988	1978	0	-2.70	0	FALSE	0
2080	47500	1995	1978	0	-33.10	0	FALSE	0
2081	47500	2011	1978	8	257,255.88	0	FALSE	0
2082	47500	1991	1979	0	-5.90	0	FALSE	0
2083	47500	1992	1979	0	-1.40	0	FALSE	0
2084	47500	2001	1979	0	-6.90	0	FALSE	0
2085	47500	2011	1979	8	17,007.99	0	FALSE	0
2086	47500	1985	1980	0	-57.00	0	FALSE	0
2087	47500	1997	1980	0	-8.30	0	FALSE	0
2088	47500	1998	1980	0	-8.30	0	FALSE	0
2089	47500	1999	1980	0	-450.70	0	FALSE	0
2090	47500	2000	1980	0	-7.40	0	FALSE	0
2091	47500	2001	1980	0	-32.40	0	FALSE	0
2092	47500	2002	1980	0	-16.70	0	FALSE	0
2093	47500	2011	1980	0	-588.00	0	FALSE	0
2094	47500	2011	1980	8	716,055.98	0	FALSE	0
2095	47500	2011	1981	8	23,266.00	0	FALSE	0
2096	47500	1989	1982	0	-7.60	0	FALSE	0
2097	47500	2011	1982	8	49,311.39	0	FALSE	0
2098	47500	1990	1983	0	-1.70	0	FALSE	0
2099	47500	2011	1983	8	68,295.31	0	FALSE	0
2100	47500	1988	1984	0	-2.20	0	FALSE	0
2101	47500	1989	1984	0	-1.60	0	FALSE	0
2102	47500	1990	1984	0	-9.30	0	FALSE	0
2103	47500	1999	1984	0	-2,151.40	0	FALSE	0
2104	47500	2011	1984	8	32,676.52	0	FALSE	0
2105	47500	1994	1985	0	-25.40	0	FALSE	0
2106	47500	1997	1985	0	-516.70	0	FALSE	0
2107	47500	1998	1985	0	-18.50	0	FALSE	0
2108	47500	2011	1985	8	61,229.70	0	FALSE	0
2109	47500	1995	1986	0	-331.60	0	FALSE	0
2110	47500	2011	1986	8	21,965.42	0	FALSE	0
2111	47500	1999	1987	0	-78.20	0	FALSE	0
2112	47500	2003	1987	0	-514.70	0	FALSE	0
2113	47500	2003	1987	0	-9.90	0	FALSE	0
2114	47500	2011	1987	8	181,124.12	0	FALSE	0
2115	47500	1998	1988	0	-20.50	0	FALSE	0
2116	47500	2000	1988	0	-839.00	0	FALSE	0
2117	47500	2011	1988	8	70,261.38	0	FALSE	0
2118	47500	1995	1989	0	-304.80	0	FALSE	0
2119	47500	1996	1989	0	-251.50	0	FALSE	0

2120	47500	2011	1989	8	1,382,612.06	0	FALSE	0
2121	47500	1995	1990	0	-38.70	0	FALSE	0
2122	47500	1999	1990	0	-20.50	0	FALSE	0
2123	47500	2011	1990	8	239,241.64	0	FALSE	0
2124	47500	1992	1991	3	-519.20	0	FALSE	0
2125	47500	2011	1991	8	171,937.17	0	FALSE	0
2126	47500	2004	1992	0	-1,445.40	0	FALSE	0
2127	47500	2011	1992	8	736,477.56	0	FALSE	0
2128	47500	2011	1993	8	996,540.23	0	FALSE	0
2129	47500	1994	1994	4	-1,449.90	1994	FALSE	0
2130	47500	1995	1994	0	-199.80	0	FALSE	0
2131	47500	2011	1994	8	267,822.74	0	FALSE	0
2132	47500	2011	1995	8	1,124,713.96	0	FALSE	0
2133	47500	1996	1996	4	336.18	1996	FALSE	0
2134	47500	2011	1996	8	533,259.01	0	FALSE	0
2135	47500	2000	1997	0	-6.70	0	FALSE	0
2136	47500	2011	1997	8	1,120,397.24	0	FALSE	0
2137	47500	2011	1998	8	658,133.08	0	FALSE	0
2138	47500	2001	1999	0	-379.00	0	FALSE	0
2139	47500	2010	1999	0	-1,186.00	0	FALSE	0
2140	47500	2011	1999	8	875,078.79	0	FALSE	0
2141	47500	2001	2000	3	-11.60	2000	FALSE	0
2142	47500	2011	2000	8	527,543.67	0	FALSE	0
2143	47500	2011	2001	8	1,723,813.98	0	FALSE	0
2144	47500	2002	2002	0	-306.00	0	FALSE	0
2145	47500	2004	2002	0	-660.70	0	FALSE	0
2146	47500	2011	2002	8	1,013,816.38	0	FALSE	0
2147	47500	2011	2003	8	1,153,334.82	0	FALSE	0
2148	47500	2006	2004	0	-967.00	0	FALSE	0
2149	47500	2011	2004	8	997,611.57	0	FALSE	0
2150	47500	2008	2005	3	-694.10	2005	FALSE	0
2151	47500	2011	2005	8	724,497.68	0	FALSE	0
2152	47500	2008	2006	4	185.83	2006	FALSE	0
2153	47500	2009	2006	4	1,068.18	0	FALSE	0
2154	47500	2010	2006	0	-676.30	0	FALSE	0
2155	47500	2011	2006	8	740,562.48	0	FALSE	0
2156	47500	2008	2007	3	-3,408.70	2007	FALSE	0
2157	47500	2009	2007	4	-290.10	0	FALSE	0
2158	47500	2010	2007	3	-14.30	0	FALSE	0
2159	47500	2011	2007	3	-0.20	2007	FALSE	0
2160	47500	2011	2007	8	826,505.65	0	FALSE	0
2161	47500	2009	2008	4	-5,311.70	0	FALSE	0
2162	47500	2010	2008	3	-2,867.60	0	FALSE	0
2163	47500	2011	2008	8	823,804.14	0	FALSE	0
2164	47500	2010	2009	4	27,362.99	0	FALSE	0
2165	47500	2011	2009	4	731.71	2009	FALSE	0
2166	47500	2011	2009	8	1,222,366.98	0	FALSE	0
2167	47500	2011	2010	4	39,219.40	2010	FALSE	0
2168	47500	2011	2010	8	627,766.58	0	FALSE	0
2169	47500	2011	2011	8	888,477.52	0	FALSE	0
2170	47510	1991	1971	0	-1.10	0	FALSE	0
2171	47510	2010	1971	0	-67.00	0	FALSE	0
2172	47510	2011	1971	8	0.00	0	FALSE	0

2173	47510	2010	1977	0	-1,355.00	0	FALSE	0
2174	47510	2011	1977	8	0.00	0	FALSE	0
2175	47510	2010	1978	0	-2,816.50	0	FALSE	0
2176	47510	2011	1978	0	-372.90	0	FALSE	0
2177	47510	2011	1978	8	8,805.65	0	FALSE	0
2178	47510	2011	1979	0	-145.10	0	FALSE	0
2179	47510	2011	1979	8	16,155.81	0	FALSE	0
2180	47510	2011	1980	0	-82.40	0	FALSE	0
2181	47510	2011	1980	8	5,116.57	0	FALSE	0
2182	47510	2011	1981	0	-163.70	0	FALSE	0
2183	47510	2011	1981	8	14,328.30	0	FALSE	0
2184	47510	2011	1982	0	-151.10	0	FALSE	0
2185	47510	2011	1982	8	6,135.87	0	FALSE	0
2186	47510	2011	1983	0	-73.80	0	FALSE	0
2187	47510	2011	1983	8	4,112.25	0	FALSE	0
2188	47510	2011	1984	0	-52.30	0	FALSE	0
2189	47510	2011	1984	8	6,049.74	0	FALSE	0
2190	47510	2011	1985	0	-280.70	0	FALSE	0
2191	47510	2011	1985	8	2,467.31	0	FALSE	0
2192	47510	2011	1986	0	-149.20	0	FALSE	0
2193	47510	2011	1986	8	47,595.84	0	FALSE	0
2194	47510	2011	1987	0	-162.80	0	FALSE	0
2195	47510	2011	1987	8	64,385.16	0	FALSE	0
2196	47510	2010	1988	0	-2,245.20	0	FALSE	0
2197	47510	2011	1988	0	-45.70	0	FALSE	0
2198	47510	2011	1988	8	55,348.04	0	FALSE	0
2199	47510	2010	1989	0	-1,993.10	0	FALSE	0
2200	47510	2011	1989	0	-53.70	0	FALSE	0
2201	47510	2011	1989	8	64,252.19	0	FALSE	0
2202	47510	2010	1990	0	-5,710.00	0	FALSE	0
2203	47510	2011	1990	0	-56.80	0	FALSE	0
2204	47510	2011	1990	8	63,917.48	0	FALSE	0
2205	47510	2010	1991	0	-3,782.20	0	FALSE	0
2206	47510	2011	1991	0	-562.20	0	FALSE	0
2207	47510	2011	1991	8	85,692.58	0	FALSE	0
2208	47510	2010	1992	0	-4,103.00	0	FALSE	0
2209	47510	2011	1992	0	-120.00	0	FALSE	0
2210	47510	2011	1992	8	151,300.89	0	FALSE	0
2211	47510	2011	1993	0	-119.10	0	FALSE	0
2212	47510	2011	1993	8	198,187.47	0	FALSE	0
2213	47510	2011	1994	0	-88.80	0	FALSE	0
2214	47510	2011	1994	8	84,909.93	0	FALSE	0
2215	47510	2011	1995	0	-548.30	0	FALSE	0
2216	47510	2011	1995	8	123,873.01	0	FALSE	0
2217	47510	2011	1996	0	-389.40	0	FALSE	0
2218	47510	2011	1996	8	226,325.88	0	FALSE	0
2219	47510	2011	1997	0	-237.90	0	FALSE	0
2220	47510	2011	1997	8	125,671.06	0	FALSE	0
2221	47510	2011	1998	0	-204.30	0	FALSE	0
2222	47510	2011	1998	8	99,659.29	0	FALSE	0
2223	47510	2011	1999	0	-556.20	0	FALSE	0
2224	47510	2011	1999	8	72,633.75	0	FALSE	0
2225	47510	2010	2000	0	-3,044.00	0	FALSE	0

2226	47510	2011	2000	0	-175.20	0	FALSE	0
2227	47510	2011	2000	8	15,457.57	0	FALSE	0
2228	47510	2006	2001	4	25.00	0	FALSE	0
2229	47510	2010	2001	0	-1,235.20	0	FALSE	0
2230	47510	2011	2001	0	-1,539.30	0	FALSE	0
2231	47510	2011	2001	8	64,800.69	0	FALSE	0
2232	47510	2010	2002	0	-1,581.90	0	FALSE	0
2233	47510	2011	2002	0	-912.30	0	FALSE	0
2234	47510	2011	2002	8	71,681.66	0	FALSE	0
2235	47510	2010	2003	0	-1,241.30	0	FALSE	0
2236	47510	2011	2003	0	-1,019.70	0	FALSE	0
2237	47510	2011	2003	8	75,033.52	0	FALSE	0
2238	47510	2010	2004	0	-952.40	0	FALSE	0
2239	47510	2011	2004	0	-1,445.20	0	FALSE	0
2240	47510	2011	2004	8	206,861.36	0	FALSE	0
2241	47510	2008	2005	3	-2.90	2005	FALSE	0
2242	47510	2011	2005	0	-818.10	0	FALSE	0
2243	47510	2011	2005	8	148,375.29	0	FALSE	0
2244	47510	2011	2006	0	-254.40	0	FALSE	0
2245	47510	2011	2006	8	233,234.91	0	FALSE	0
2246	47510	2008	2007	4	214.40	2007	FALSE	0
2247	47510	2010	2007	0	-514.30	0	FALSE	0
2248	47510	2011	2007	0	-233.90	0	FALSE	0
2249	47510	2011	2007	8	163,236.52	0	FALSE	0
2250	47510	2009	2008	4	71.31	0	FALSE	0
2251	47510	2011	2008	0	-169.80	0	FALSE	0
2252	47510	2011	2008	8	95,096.67	0	FALSE	0
2253	47510	2010	2009	4	259.53	0	FALSE	0
2254	47510	2011	2009	0	-94.50	0	FALSE	0
2255	47510	2011	2009	8	39,357.36	0	FALSE	0
2256	47510	2011	2010	0	-135.80	0	FALSE	0
2257	47510	2011	2010	3	-624.20	2010	FALSE	0
2258	47510	2011	2010	8	94,836.76	0	FALSE	0
2259	47510	2011	2011	8	218,180.81	0	FALSE	0
2260	47610	1960	1945	0	-608.00	0	FALSE	0
2261	47610	1961	1945	0	-2,130.00	0	FALSE	0
2262	47610	1962	1945	0	-235.00	0	FALSE	0
2263	47610	1980	1945	0	-3,870.00	0	FALSE	0
2264	47610	1962	1946	0	-447.00	0	FALSE	0
2265	47610	1980	1946	0	-580.00	0	FALSE	0
2266	47610	1962	1947	0	-513.00	0	FALSE	0
2267	47610	1980	1947	0	-667.00	0	FALSE	0
2268	47610	1962	1948	0	-28.00	0	FALSE	0
2269	47610	1963	1948	0	-561.00	0	FALSE	0
2270	47610	1980	1948	0	-768.00	0	FALSE	0
2271	47610	1963	1949	0	-205.00	0	FALSE	0
2272	47610	1964	1949	0	-215.00	0	FALSE	0
2273	47610	1965	1949	0	-207.00	0	FALSE	0
2274	47610	1966	1949	0	-51.00	0	FALSE	0
2275	47610	1980	1949	0	-883.00	0	FALSE	0
2276	47610	1966	1950	0	-780.00	0	FALSE	0
2277	47610	1980	1950	0	-1,015.00	0	FALSE	0
2278	47610	1966	1951	0	-304.00	0	FALSE	0

2279	47610	1967	1951	0	-214.00	0	FALSE	0
2280	47610	1968	1951	0	-379.00	0	FALSE	0
2281	47610	1980	1951	0	-1,168.00	0	FALSE	0
2282	47610	1968	1952	0	-498.00	0	FALSE	0
2283	47610	1969	1952	0	-365.00	0	FALSE	0
2284	47610	1970	1952	0	-513.00	0	FALSE	0
2285	47610	1980	1952	0	-26.00	0	FALSE	0
2286	47610	1983	1952	0	-370.00	0	FALSE	0
2287	47610	1986	1952	0	-1,394.00	0	FALSE	0
2288	47610	1970	1953	0	-45.00	0	FALSE	0
2289	47610	1971	1953	0	-2,431.00	0	FALSE	0
2290	47610	1983	1953	0	-65.00	0	FALSE	0
2291	47610	1984	1953	0	-1,062.00	0	FALSE	0
2292	47610	1986	1953	0	-2,095.00	0	FALSE	0
2293	47610	1971	1954	0	-1,176.00	0	FALSE	0
2294	47610	1973	1954	0	-1,997.00	0	FALSE	0
2295	47610	1974	1954	0	-45.00	0	FALSE	0
2296	47610	1982	1954	0	-1,096.00	0	FALSE	0
2297	47610	1983	1954	0	-71.00	0	FALSE	0
2298	47610	1984	1954	0	-2,921.00	0	FALSE	0
2299	47610	1986	1954	0	-101.00	0	FALSE	0
2300	47610	1974	1955	0	-1,562.00	0	FALSE	0
2301	47610	1975	1955	0	-1,228.00	0	FALSE	0
2302	47610	1981	1955	0	-827.00	0	FALSE	0
2303	47610	1983	1955	0	-62.00	0	FALSE	0
2304	47610	1986	1955	0	-1,893.00	0	FALSE	0
2305	47610	1987	1955	0	-848.00	0	FALSE	0
2306	47610	1975	1956	0	-3,097.00	0	FALSE	0
2307	47610	1976	1956	0	-251.00	0	FALSE	0
2308	47610	1981	1956	0	-949.00	0	FALSE	0
2309	47610	1983	1956	0	-94.00	0	FALSE	0
2310	47610	1987	1956	0	-3,313.00	0	FALSE	0
2311	47610	1976	1957	0	-4,016.00	0	FALSE	0
2312	47610	1977	1957	0	-2,561.00	0	FALSE	0
2313	47610	1978	1957	0	-1,896.00	0	FALSE	0
2314	47610	1979	1957	0	-771.00	0	FALSE	0
2315	47610	1972	1958	0	-615.00	0	FALSE	0
2316	47610	1973	1958	0	-188.00	0	FALSE	0
2317	47610	1978	1958	0	-352.00	0	FALSE	0
2318	47610	1979	1958	0	-1,127.00	0	FALSE	0
2319	47610	1969	1959	0	-24.00	0	FALSE	0
2320	47610	1978	1959	0	-800.00	0	FALSE	0
2321	47610	1979	1959	0	-428.00	0	FALSE	0
2322	47610	1981	1959	0	-275.00	0	FALSE	0
2323	47610	1983	1959	0	-289.00	0	FALSE	0
2324	47610	1987	1959	0	-6,000.00	0	FALSE	0
2325	47610	1978	1960	0	-360.00	0	FALSE	0
2326	47610	1979	1960	0	-102.00	0	FALSE	0
2327	47610	1981	1960	0	-552.00	0	FALSE	0
2328	47610	1982	1960	0	-1,941.00	0	FALSE	0
2329	47610	1983	1960	0	-170.00	0	FALSE	0
2330	47610	1984	1960	0	-3,523.00	0	FALSE	0
2331	47610	1987	1960	0	-696.00	0	FALSE	0

2332	47610	1981	1961	0	-542.00	0	FALSE	0
2333	47610	1983	1961	0	-97.00	0	FALSE	0
2334	47610	1987	1961	0	-6,100.00	0	FALSE	0
2335	47610	1978	1962	0	-119.00	0	FALSE	0
2336	47610	1979	1962	0	-180.00	0	FALSE	0
2337	47610	1981	1962	0	-428.00	0	FALSE	0
2338	47610	1982	1962	0	-1,762.00	0	FALSE	0
2339	47610	1983	1962	0	-125.00	0	FALSE	0
2340	47610	1987	1962	0	-636.00	0	FALSE	0
2341	47610	1988	1962	0	-3,055.00	0	FALSE	0
2342	47610	1989	1962	0	-1,892.00	0	FALSE	0
2343	47610	1973	1963	0	-22.00	0	FALSE	0
2344	47610	1981	1963	0	-499.00	0	FALSE	0
2345	47610	1983	1963	0	-68.00	0	FALSE	0
2346	47610	1987	1963	0	-605.00	0	FALSE	0
2347	47610	1988	1963	0	-4,816.00	0	FALSE	0
2348	47610	1989	1963	0	-2,395.00	0	FALSE	0
2349	47610	1977	1964	0	-63.00	0	FALSE	0
2350	47610	1979	1964	0	-109.00	0	FALSE	0
2351	47610	1981	1964	0	-429.00	0	FALSE	0
2352	47610	1983	1964	0	-192.00	0	FALSE	0
2353	47610	1989	1964	0	-2,014.00	0	FALSE	0
2354	47610	1978	1965	0	-22.00	0	FALSE	0
2355	47610	1979	1965	0	-616.00	0	FALSE	0
2356	47610	1981	1965	0	-338.00	0	FALSE	0
2357	47610	1983	1965	0	-171.00	0	FALSE	0
2358	47610	1989	1965	0	-1,393.00	0	FALSE	0
2359	47610	1990	1965	0	-2,907.50	0	FALSE	0
2360	47610	1981	1966	0	-295.00	0	FALSE	0
2361	47610	1983	1966	0	-256.00	0	FALSE	0
2362	47610	1990	1966	0	-4,747.90	0	FALSE	0
2363	47610	1991	1966	0	-2,476.10	0	FALSE	0
2364	47610	1978	1967	0	-604.00	0	FALSE	0
2365	47610	1981	1967	0	-373.00	0	FALSE	0
2366	47610	1982	1967	0	-1,165.00	0	FALSE	0
2367	47610	1983	1967	0	-223.00	0	FALSE	0
2368	47610	1991	1967	0	-5,373.60	0	FALSE	0
2369	47610	1992	1967	0	-1,609.50	0	FALSE	0
2370	47610	1993	1967	0	-1,309.90	0	FALSE	0
2371	47610	1972	1968	0	-43.00	0	FALSE	0
2372	47610	1973	1968	0	-22.00	0	FALSE	0
2373	47610	1974	1968	0	-59.00	0	FALSE	0
2374	47610	1981	1968	0	-471.00	0	FALSE	0
2375	47610	1983	1968	0	-123.00	0	FALSE	0
2376	47610	1992	1968	0	-2,262.00	0	FALSE	0
2377	47610	1993	1968	0	-794.60	0	FALSE	0
2378	47610	1994	1968	0	-5,098.00	0	FALSE	0
2379	47610	1995	1968	0	-1,708.90	0	FALSE	0
2380	47610	1996	1968	0	-1,903.50	0	FALSE	0
2381	47610	1997	1968	0	-2,917.70	0	FALSE	0
2382	47610	1998	1968	0	-1,064.30	0	FALSE	0
2383	47610	1999	1968	0	-4,588.40	0	FALSE	0
2384	47610	2000	1968	0	-8,189.10	0	FALSE	0

2385	47610	2001	1968	0	-1,468.00	0	FALSE	0
2386	47610	2002	1968	0	-406.40	0	FALSE	0
2387	47610	1972	1969	0	-22.00	0	FALSE	0
2388	47610	1981	1969	0	-432.00	0	FALSE	0
2389	47610	1983	1969	0	-78.00	0	FALSE	0
2390	47610	1984	1969	0	-142.00	0	FALSE	0
2391	47610	1992	1969	0	-9,196.00	0	FALSE	0
2392	47610	1993	1969	0	-45.70	0	FALSE	0
2393	47610	1994	1969	0	-1,797.30	0	FALSE	0
2394	47610	1995	1969	0	-352.10	0	FALSE	0
2395	47610	1996	1969	0	-256.10	0	FALSE	0
2396	47610	1997	1969	0	-390.00	0	FALSE	0
2397	47610	1998	1969	0	-139.70	0	FALSE	0
2398	47610	1999	1969	0	-654.30	0	FALSE	0
2399	47610	2000	1969	0	-881.90	0	FALSE	0
2400	47610	2001	1969	0	-283.90	0	FALSE	0
2401	47610	2002	1969	0	-1,556.40	0	FALSE	0
2402	47610	2005	1969	0	-303.70	0	FALSE	0
2403	47610	2010	1969	0	-95.90	0	FALSE	0
2404	47610	2011	1969	8	0.00	0	FALSE	0
2405	47610	1981	1970	0	-275.00	0	FALSE	0
2406	47610	1983	1970	0	-213.00	0	FALSE	0
2407	47610	1984	1970	0	-5.00	0	FALSE	0
2408	47610	1993	1970	0	-125.30	0	FALSE	0
2409	47610	1994	1970	0	-920.10	0	FALSE	0
2410	47610	1995	1970	0	-672.80	0	FALSE	0
2411	47610	1996	1970	0	-487.90	0	FALSE	0
2412	47610	1997	1970	0	-801.80	0	FALSE	0
2413	47610	1998	1970	0	-651.20	0	FALSE	0
2414	47610	1999	1970	0	-942.20	0	FALSE	0
2415	47610	2000	1970	0	-1,238.90	0	FALSE	0
2416	47610	2001	1970	0	-277.40	0	FALSE	0
2417	47610	2002	1970	0	-749.10	0	FALSE	0
2418	47610	2005	1970	0	-163.90	0	FALSE	0
2419	47610	2006	1970	0	-754.00	0	FALSE	0
2420	47610	2010	1970	0	-7,089.90	0	FALSE	0
2421	47610	2011	1970	0	-70.30	0	FALSE	0
2422	47610	2011	1970	8	18.15	0	FALSE	0
2423	47610	1972	1971	0	-52.00	0	FALSE	0
2424	47610	1978	1971	0	-22.00	0	FALSE	0
2425	47610	1979	1971	0	-22.00	0	FALSE	0
2426	47610	1981	1971	0	-267.00	0	FALSE	0
2427	47610	1983	1971	0	-10.00	0	FALSE	0
2428	47610	1993	1971	0	-214.80	0	FALSE	0
2429	47610	1994	1971	0	-451.70	0	FALSE	0
2430	47610	1995	1971	0	-865.50	0	FALSE	0
2431	47610	1996	1971	0	-283.90	0	FALSE	0
2432	47610	1997	1971	0	-604.90	0	FALSE	0
2433	47610	1998	1971	0	-338.10	0	FALSE	0
2434	47610	1999	1971	0	-845.80	0	FALSE	0
2435	47610	2000	1971	0	-1,755.50	0	FALSE	0
2436	47610	2001	1971	0	-370.90	0	FALSE	0
2437	47610	2002	1971	0	-806.80	0	FALSE	0

2438	47610	2005	1971	0	-42.60	0	FALSE	0
2439	47610	2006	1971	0	-2,455.20	0	FALSE	0
2440	47610	2010	1971	0	-1,411.00	0	FALSE	0
2441	47610	2011	1971	0	-4,874.50	0	FALSE	0
2442	47610	2011	1971	8	4,291.77	0	FALSE	0
2443	47610	1979	1972	0	-115.00	0	FALSE	0
2444	47610	1981	1972	0	-262.00	0	FALSE	0
2445	47610	1982	1972	0	-172.00	0	FALSE	0
2446	47610	1983	1972	0	-24.00	0	FALSE	0
2447	47610	1993	1972	0	-112.80	0	FALSE	0
2448	47610	1994	1972	0	-396.20	0	FALSE	0
2449	47610	1995	1972	0	-606.80	0	FALSE	0
2450	47610	1996	1972	0	-590.10	0	FALSE	0
2451	47610	1997	1972	0	-939.10	0	FALSE	0
2452	47610	1998	1972	0	-339.60	0	FALSE	0
2453	47610	1999	1972	0	-1,055.50	0	FALSE	0
2454	47610	2000	1972	0	-1,833.40	0	FALSE	0
2455	47610	2001	1972	0	-476.50	0	FALSE	0
2456	47610	2002	1972	0	-875.10	0	FALSE	0
2457	47610	2005	1972	0	-323.50	0	FALSE	0
2458	47610	2010	1972	0	-376.30	0	FALSE	0
2459	47610	2011	1972	0	-436.40	0	FALSE	0
2460	47610	2011	1972	8	4,159.27	0	FALSE	0
2461	47610	1978	1973	0	-193.00	0	FALSE	0
2462	47610	1979	1973	0	-113.00	0	FALSE	0
2463	47610	1981	1973	0	-308.00	0	FALSE	0
2464	47610	1983	1973	0	-8.00	0	FALSE	0
2465	47610	1993	1973	0	-31.00	0	FALSE	0
2466	47610	1994	1973	0	-267.90	0	FALSE	0
2467	47610	1995	1973	0	-359.00	0	FALSE	0
2468	47610	1996	1973	0	-384.30	0	FALSE	0
2469	47610	1997	1973	0	-734.90	0	FALSE	0
2470	47610	1998	1973	0	-364.80	0	FALSE	0
2471	47610	1999	1973	0	-1,144.60	0	FALSE	0
2472	47610	2000	1973	0	-1,114.20	0	FALSE	0
2473	47610	2001	1973	0	-486.00	0	FALSE	0
2474	47610	2002	1973	0	-911.60	0	FALSE	0
2475	47610	2005	1973	0	-4,822.00	0	FALSE	0
2476	47610	2010	1973	0	-1,056.90	0	FALSE	0
2477	47610	2011	1973	0	-7,607.70	0	FALSE	0
2478	47610	2011	1973	8	4,922.20	0	FALSE	0
2479	47610	1978	1974	0	-142.00	0	FALSE	0
2480	47610	1979	1974	0	-115.00	0	FALSE	0
2481	47610	1981	1974	0	-326.00	0	FALSE	0
2482	47610	1982	1974	0	-2,312.00	0	FALSE	0
2483	47610	1983	1974	0	-6.00	0	FALSE	0
2484	47610	1993	1974	0	-16.30	0	FALSE	0
2485	47610	1994	1974	0	-182.70	0	FALSE	0
2486	47610	1995	1974	0	-570.00	0	FALSE	0
2487	47610	1996	1974	0	-428.90	0	FALSE	0
2488	47610	1997	1974	0	-915.40	0	FALSE	0
2489	47610	1998	1974	0	-417.60	0	FALSE	0
2490	47610	1999	1974	0	-1,397.50	0	FALSE	0

2491	47610	2000	1974	0	-2,679.70	0	FALSE	0
2492	47610	2001	1974	0	-808.00	0	FALSE	0
2493	47610	2002	1974	0	-1,188.00	0	FALSE	0
2494	47610	2005	1974	0	-1,403.80	0	FALSE	0
2495	47610	2006	1974	0	-234.40	0	FALSE	0
2496	47610	2011	1974	8	1,065.68	0	FALSE	0
2497	47610	1978	1975	0	-22.00	0	FALSE	0
2498	47610	1979	1975	0	-88.00	0	FALSE	0
2499	47610	1983	1975	0	-3.00	0	FALSE	0
2500	47610	1992	1975	0	-1,178.90	0	FALSE	0
2501	47610	1993	1975	0	-19.90	0	FALSE	0
2502	47610	1994	1975	0	-104.80	0	FALSE	0
2503	47610	1995	1975	0	-324.70	0	FALSE	0
2504	47610	1996	1975	0	-374.10	0	FALSE	0
2505	47610	1997	1975	0	-653.40	0	FALSE	0
2506	47610	1998	1975	0	-293.20	0	FALSE	0
2507	47610	1999	1975	0	-969.30	0	FALSE	0
2508	47610	2000	1975	0	-2,457.80	0	FALSE	0
2509	47610	2001	1975	0	-1,099.70	0	FALSE	0
2510	47610	2002	1975	0	-1,044.60	0	FALSE	0
2511	47610	2005	1975	0	-994.30	0	FALSE	0
2512	47610	2006	1975	0	-823.40	0	FALSE	0
2513	47610	2010	1975	0	-435.20	0	FALSE	0
2514	47610	2011	1975	0	-348.10	0	FALSE	0
2515	47610	2011	1975	8	10,392.34	0	FALSE	0
2516	47610	1982	1976	0	-3,218.00	0	FALSE	0
2517	47610	1983	1976	0	-8.00	0	FALSE	0
2518	47610	1992	1976	0	-124.10	0	FALSE	0
2519	47610	1993	1976	0	-50.60	0	FALSE	0
2520	47610	1994	1976	0	-335.60	0	FALSE	0
2521	47610	1995	1976	0	-752.30	0	FALSE	0
2522	47610	1996	1976	0	-696.10	0	FALSE	0
2523	47610	1997	1976	0	-1,120.20	0	FALSE	0
2524	47610	1998	1976	0	-475.20	0	FALSE	0
2525	47610	1999	1976	0	-1,780.80	0	FALSE	0
2526	47610	2000	1976	0	-3,667.40	0	FALSE	0
2527	47610	2001	1976	0	-1,762.80	0	FALSE	0
2528	47610	2002	1976	0	-1,660.20	0	FALSE	0
2529	47610	2005	1976	0	-6,370.30	0	FALSE	0
2530	47610	2006	1976	0	-286.10	0	FALSE	0
2531	47610	2010	1976	0	-1,963.50	0	FALSE	0
2532	47610	2011	1976	0	-4,388.20	0	FALSE	0
2533	47610	2011	1976	8	3,532.46	0	FALSE	0
2534	47610	1983	1977	0	-7,879.00	0	FALSE	0
2535	47610	1993	1977	0	-18.20	0	FALSE	0
2536	47610	1994	1977	0	-121.60	0	FALSE	0
2537	47610	1995	1977	0	-631.00	0	FALSE	0
2538	47610	1996	1977	0	-627.00	0	FALSE	0
2539	47610	1997	1977	0	-899.60	0	FALSE	0
2540	47610	1998	1977	0	-523.20	0	FALSE	0
2541	47610	1999	1977	0	-1,638.30	0	FALSE	0
2542	47610	2000	1977	0	-4,025.10	0	FALSE	0
2543	47610	2001	1977	0	-2,016.40	0	FALSE	0

2544	47610	2002	1977	0	-2,273.70	0	FALSE	0
2545	47610	2005	1977	0	-304.60	0	FALSE	0
2546	47610	2011	1977	8	2,160.36	0	FALSE	0
2547	47610	1979	1978	0	-31.00	0	FALSE	0
2548	47610	1983	1978	0	-7.00	0	FALSE	0
2549	47610	1989	1978	0	-239.00	0	FALSE	0
2550	47610	1993	1978	0	-182.50	0	FALSE	0
2551	47610	1994	1978	0	-179.50	0	FALSE	0
2552	47610	1995	1978	0	-846.30	0	FALSE	0
2553	47610	1996	1978	0	-1,061.50	0	FALSE	0
2554	47610	1997	1978	0	-1,194.20	0	FALSE	0
2555	47610	1998	1978	0	-622.40	0	FALSE	0
2556	47610	1999	1978	0	-1,819.00	0	FALSE	0
2557	47610	2000	1978	0	-3,275.20	0	FALSE	0
2558	47610	2001	1978	0	-1,332.70	0	FALSE	0
2559	47610	2002	1978	0	-2,665.40	0	FALSE	0
2560	47610	2005	1978	0	-15,713.00	0	FALSE	0
2561	47610	2006	1978	0	-952.70	0	FALSE	0
2562	47610	2010	1978	0	-10,510.30	0	FALSE	0
2563	47610	2011	1978	8	3,961.72	0	FALSE	0
2564	47610	1983	1979	0	-37.00	0	FALSE	0
2565	47610	1992	1979	0	-164.40	0	FALSE	0
2566	47610	1993	1979	0	-241.20	0	FALSE	0
2567	47610	1994	1979	0	-649.30	0	FALSE	0
2568	47610	1995	1979	0	-1,222.10	0	FALSE	0
2569	47610	1996	1979	0	-1,190.80	0	FALSE	0
2570	47610	1997	1979	0	-1,431.10	0	FALSE	0
2571	47610	1998	1979	0	-824.10	0	FALSE	0
2572	47610	1999	1979	0	-2,651.30	0	FALSE	0
2573	47610	2000	1979	0	-5,706.30	0	FALSE	0
2574	47610	2001	1979	0	-2,198.80	0	FALSE	0
2575	47610	2002	1979	0	-4,843.20	0	FALSE	0
2576	47610	2005	1979	0	-1,842.60	0	FALSE	0
2577	47610	2006	1979	0	-28.90	0	FALSE	0
2578	47610	2011	1979	8	468.92	0	FALSE	0
2579	47610	1993	1980	0	-227.30	0	FALSE	0
2580	47610	1994	1980	0	-936.30	0	FALSE	0
2581	47610	1995	1980	0	-713.60	0	FALSE	0
2582	47610	1996	1980	0	-1,420.70	0	FALSE	0
2583	47610	1997	1980	0	-2,131.00	0	FALSE	0
2584	47610	1998	1980	0	-1,450.20	0	FALSE	0
2585	47610	1999	1980	0	-3,779.70	0	FALSE	0
2586	47610	2000	1980	0	-6,571.40	0	FALSE	0
2587	47610	2001	1980	0	-2,456.20	0	FALSE	0
2588	47610	2002	1980	0	-3,740.60	0	FALSE	0
2589	47610	2011	1980	8	4,344.54	0	FALSE	0
2590	47610	1983	1981	0	-3.00	0	FALSE	0
2591	47610	1988	1981	0	-892.00	0	FALSE	0
2592	47610	1991	1981	0	-575.00	0	FALSE	0
2593	47610	1993	1981	0	-125.00	0	FALSE	0
2594	47610	1994	1981	0	-712.20	0	FALSE	0
2595	47610	1995	1981	0	-1,698.40	0	FALSE	0
2596	47610	1996	1981	0	-2,242.40	0	FALSE	0

2597	47610	1997	1981	0	-2,065.00	0	FALSE	0
2598	47610	1998	1981	0	-1,056.90	0	FALSE	0
2599	47610	1999	1981	0	-5,560.10	0	FALSE	0
2600	47610	2000	1981	0	-10,962.70	0	FALSE	0
2601	47610	2001	1981	0	-6,201.80	0	FALSE	0
2602	47610	2002	1981	0	-12,551.90	0	FALSE	0
2603	47610	2011	1981	8	3,588.21	0	FALSE	0
2604	47610	1983	1982	0	-335.00	0	FALSE	0
2605	47610	1984	1982	0	-168.00	0	FALSE	0
2606	47610	1993	1982	0	-382.40	0	FALSE	0
2607	47610	1994	1982	0	-699.40	0	FALSE	0
2608	47610	1995	1982	0	-2,199.50	0	FALSE	0
2609	47610	1996	1982	0	-1,487.50	0	FALSE	0
2610	47610	1997	1982	0	-1,444.50	0	FALSE	0
2611	47610	1998	1982	0	-804.50	0	FALSE	0
2612	47610	1999	1982	0	-4,409.90	0	FALSE	0
2613	47610	2000	1982	0	-8,314.90	0	FALSE	0
2614	47610	2001	1982	0	-1,602.20	0	FALSE	0
2615	47610	2011	1982	8	5,232.71	0	FALSE	0
2616	47610	1993	1983	0	-102.00	0	FALSE	0
2617	47610	1994	1983	0	-300.20	0	FALSE	0
2618	47610	1995	1983	0	-266.90	0	FALSE	0
2619	47610	1996	1983	0	-63.00	0	FALSE	0
2620	47610	1997	1983	0	-356.80	0	FALSE	0
2621	47610	1998	1983	0	-489.60	0	FALSE	0
2622	47610	1999	1983	0	-1,260.50	0	FALSE	0
2623	47610	2000	1983	0	-592.90	0	FALSE	0
2624	47610	2001	1983	0	-1,043.80	0	FALSE	0
2625	47610	2002	1983	0	-6,971.70	0	FALSE	0
2626	47610	2005	1983	0	-228.20	0	FALSE	0
2627	47610	2011	1983	8	562.52	0	FALSE	0
2628	47610	1987	1984	0	-575.00	0	FALSE	0
2629	47610	1988	1984	0	-113.00	0	FALSE	0
2630	47610	1989	1984	0	-1,186.00	0	FALSE	0
2631	47610	1993	1984	0	-264.20	0	FALSE	0
2632	47610	1994	1984	0	-399.80	0	FALSE	0
2633	47610	1995	1984	0	-1,594.60	0	FALSE	0
2634	47610	1996	1984	0	-800.60	0	FALSE	0
2635	47610	1997	1984	0	-933.60	0	FALSE	0
2636	47610	1998	1984	0	-767.90	0	FALSE	0
2637	47610	1999	1984	0	-2,814.90	0	FALSE	0
2638	47610	2000	1984	0	-2,833.00	0	FALSE	0
2639	47610	2001	1984	0	-2,447.40	0	FALSE	0
2640	47610	2002	1984	0	-4,551.80	0	FALSE	0
2641	47610	2005	1984	0	-1,475.50	0	FALSE	0
2642	47610	2006	1984	0	-29.00	0	FALSE	0
2643	47610	2011	1984	8	2,268.84	0	FALSE	0
2644	47610	1990	1985	0	-1,627.10	0	FALSE	0
2645	47610	1993	1985	0	-564.90	0	FALSE	0
2646	47610	1994	1985	0	-2,226.30	0	FALSE	0
2647	47610	1995	1985	0	-1,767.30	0	FALSE	0
2648	47610	1996	1985	0	-1,926.30	0	FALSE	0
2649	47610	1997	1985	0	-2,592.00	0	FALSE	0

2650	47610	1998	1985	0	-2,599.50	0	FALSE	0
2651	47610	1999	1985	0	-5,238.30	0	FALSE	0
2652	47610	2000	1985	0	-7,716.90	0	FALSE	0
2653	47610	2001	1985	0	-3,043.90	0	FALSE	0
2654	47610	2002	1985	0	-7,856.30	0	FALSE	0
2655	47610	2011	1985	8	4,581.74	0	FALSE	0
2656	47610	1993	1986	0	-449.10	0	FALSE	0
2657	47610	1994	1986	0	-348.80	0	FALSE	0
2658	47610	1995	1986	0	-673.50	0	FALSE	0
2659	47610	1996	1986	0	-898.30	0	FALSE	0
2660	47610	1997	1986	0	-2,322.90	0	FALSE	0
2661	47610	1998	1986	0	-2,721.10	0	FALSE	0
2662	47610	1999	1986	0	-3,497.30	0	FALSE	0
2663	47610	2000	1986	0	-7,169.80	0	FALSE	0
2664	47610	2001	1986	0	-2,079.10	0	FALSE	0
2665	47610	2002	1986	0	-3,944.30	0	FALSE	0
2666	47610	2011	1986	8	4,570.19	0	FALSE	0
2667	47610	1993	1987	0	-908.10	0	FALSE	0
2668	47610	1994	1987	0	-2,750.80	0	FALSE	0
2669	47610	1995	1987	0	-617.70	0	FALSE	0
2670	47610	1996	1987	0	-2,373.60	0	FALSE	0
2671	47610	1997	1987	0	-3,139.90	0	FALSE	0
2672	47610	1998	1987	0	-1,302.10	0	FALSE	0
2673	47610	1999	1987	0	-6,895.20	0	FALSE	0
2674	47610	2000	1987	0	-8,959.50	0	FALSE	0
2675	47610	2001	1987	0	-3,585.10	0	FALSE	0
2676	47610	2002	1987	0	-8,430.60	0	FALSE	0
2677	47610	2005	1987	0	-4,111.90	0	FALSE	0
2678	47610	2006	1987	0	-2,143.60	0	FALSE	0
2679	47610	2011	1987	8	8,609.54	0	FALSE	0
2680	47610	1993	1988	0	-253.00	0	FALSE	0
2681	47610	1994	1988	0	-388.00	0	FALSE	0
2682	47610	1995	1988	0	-395.90	0	FALSE	0
2683	47610	1996	1988	0	-665.70	0	FALSE	0
2684	47610	1997	1988	0	-2,996.20	0	FALSE	0
2685	47610	1998	1988	0	-556.20	0	FALSE	0
2686	47610	1999	1988	0	-2,331.60	0	FALSE	0
2687	47610	2000	1988	0	-5,705.10	0	FALSE	0
2688	47610	2001	1988	0	-2,223.40	0	FALSE	0
2689	47610	2002	1988	0	-4,333.20	0	FALSE	0
2690	47610	2005	1988	0	-2,735.90	0	FALSE	0
2691	47610	2006	1988	0	-10,763.70	0	FALSE	0
2692	47610	2010	1988	0	-12,202.00	0	FALSE	0
2693	47610	2011	1988	8	11,962.73	0	FALSE	0
2694	47610	1993	1989	0	-72.40	0	FALSE	0
2695	47610	1994	1989	0	-397.90	0	FALSE	0
2696	47610	1995	1989	0	-590.50	0	FALSE	0
2697	47610	1996	1989	0	-804.20	0	FALSE	0
2698	47610	1997	1989	0	-666.60	0	FALSE	0
2699	47610	1998	1989	0	-1,225.70	0	FALSE	0
2700	47610	1999	1989	0	-4,288.50	0	FALSE	0
2701	47610	2000	1989	0	-7,512.70	0	FALSE	0
2702	47610	2001	1989	0	-2,969.50	0	FALSE	0

2703	47610	2002	1989	0	-6,491.90	0	FALSE	0
2704	47610	2005	1989	0	-4,517.70	0	FALSE	0
2705	47610	2006	1989	0	-1,082.70	0	FALSE	0
2706	47610	2010	1989	0	-10,831.80	0	FALSE	0
2707	47610	2011	1989	0	-9,183.00	0	FALSE	0
2708	47610	2011	1989	8	35,899.48	0	FALSE	0
2709	47610	1993	1990	0	-4.60	0	FALSE	0
2710	47610	1994	1990	0	-331.30	0	FALSE	0
2711	47610	1995	1990	0	-1,061.20	0	FALSE	0
2712	47610	1996	1990	0	-907.10	0	FALSE	0
2713	47610	1997	1990	0	-694.50	0	FALSE	0
2714	47610	1998	1990	0	-542.50	0	FALSE	0
2715	47610	1999	1990	0	-3,117.20	0	FALSE	0
2716	47610	2000	1990	0	-8,227.20	0	FALSE	0
2717	47610	2001	1990	0	-4,563.70	0	FALSE	0
2718	47610	2002	1990	0	-6,965.80	0	FALSE	0
2719	47610	2005	1990	0	-5,762.60	0	FALSE	0
2720	47610	2006	1990	0	-1,466.90	0	FALSE	0
2721	47610	2010	1990	0	-31,031.70	0	FALSE	0
2722	47610	2011	1990	0	-3,687.00	0	FALSE	0
2723	47610	2011	1990	8	12,441.33	0	FALSE	0
2724	47610	1993	1991	0	-238.50	0	FALSE	0
2725	47610	1994	1991	0	-679.30	0	FALSE	0
2726	47610	1995	1991	0	-701.10	0	FALSE	0
2727	47610	1996	1991	0	-975.20	0	FALSE	0
2728	47610	1997	1991	0	-684.30	0	FALSE	0
2729	47610	1998	1991	0	-349.00	0	FALSE	0
2730	47610	1999	1991	0	-7,428.30	0	FALSE	0
2731	47610	2000	1991	0	-8,945.90	0	FALSE	0
2732	47610	2001	1991	0	-6,437.40	0	FALSE	0
2733	47610	2002	1991	0	-11,232.30	0	FALSE	0
2734	47610	2005	1991	0	-4,355.10	0	FALSE	0
2735	47610	2006	1991	0	-1,865.00	0	FALSE	0
2736	47610	2010	1991	0	-20,554.70	0	FALSE	0
2737	47610	2011	1991	0	-298.00	0	FALSE	0
2738	47610	2011	1991	8	11,062.14	0	FALSE	0
2739	47610	1993	1992	0	-192.40	0	FALSE	0
2740	47610	1994	1992	0	-487.80	0	FALSE	0
2741	47610	1995	1992	0	-863.00	0	FALSE	0
2742	47610	1996	1992	0	-657.70	0	FALSE	0
2743	47610	1997	1992	0	-689.80	0	FALSE	0
2744	47610	1998	1992	0	-335.50	0	FALSE	0
2745	47610	1999	1992	0	-5,784.90	0	FALSE	0
2746	47610	2000	1992	0	-14,092.50	0	FALSE	0
2747	47610	2001	1992	0	-6,807.60	0	FALSE	0
2748	47610	2002	1992	0	-10,446.60	0	FALSE	0
2749	47610	2005	1992	0	-23,690.60	0	FALSE	0
2750	47610	2006	1992	0	-1,498.60	0	FALSE	0
2751	47610	2010	1992	0	-22,298.20	0	FALSE	0
2752	47610	2011	1992	8	35,072.97	0	FALSE	0
2753	47610	1994	1993	0	-1,250.20	0	FALSE	0
2754	47610	1995	1993	0	-1,683.40	0	FALSE	0
2755	47610	1996	1993	0	-4,403.00	0	FALSE	0

2756	47610	1997	1993	0	-4,690.70	0	FALSE	0
2757	47610	1998	1993	0	-658.30	0	FALSE	0
2758	47610	1999	1993	0	-5,497.10	0	FALSE	0
2759	47610	2000	1993	0	-9,389.90	0	FALSE	0
2760	47610	2001	1993	0	-4,423.40	0	FALSE	0
2761	47610	2002	1993	0	-7,415.20	0	FALSE	0
2762	47610	2005	1993	0	-16,400.60	0	FALSE	0
2763	47610	2006	1993	0	-423.60	0	FALSE	0
2764	47610	2011	1993	8	62,568.13	0	FALSE	0
2765	47610	1994	1994	0	-886.70	0	FALSE	0
2766	47610	1995	1994	0	-338.10	0	FALSE	0
2767	47610	1996	1994	0	-588.00	0	FALSE	0
2768	47610	1997	1994	0	-233.20	0	FALSE	0
2769	47610	1998	1994	0	-453.10	0	FALSE	0
2770	47610	1999	1994	0	-2,200.30	0	FALSE	0
2771	47610	2000	1994	0	-15,142.60	0	FALSE	0
2772	47610	2001	1994	0	-6,316.00	0	FALSE	0
2773	47610	2002	1994	0	-18,742.40	0	FALSE	0
2774	47610	2011	1994	8	6,205.20	0	FALSE	0
2775	47610	1995	1995	0	-177.20	0	FALSE	0
2776	47610	1996	1995	0	-43.00	0	FALSE	0
2777	47610	1997	1995	0	-344.40	0	FALSE	0
2778	47610	1998	1995	0	-142.70	0	FALSE	0
2779	47610	1999	1995	0	-1,858.00	0	FALSE	0
2780	47610	2000	1995	0	-20,780.00	0	FALSE	0
2781	47610	2001	1995	0	-2,324.40	0	FALSE	0
2782	47610	2011	1995	8	9,796.96	0	FALSE	0
2783	47610	1996	1996	0	-1,410.50	0	FALSE	0
2784	47610	1997	1996	0	-149.90	0	FALSE	0
2785	47610	1998	1996	0	-809.80	0	FALSE	0
2786	47610	1999	1996	0	-26,605.90	0	FALSE	0
2787	47610	2000	1996	0	-6,504.60	0	FALSE	0
2788	47610	2001	1996	0	-1,795.50	0	FALSE	0
2789	47610	2011	1996	8	8,617.32	0	FALSE	0
2790	47610	1998	1997	0	-27.20	0	FALSE	0
2791	47610	1999	1997	0	-460.70	0	FALSE	0
2792	47610	2000	1997	0	-3,793.40	0	FALSE	0
2793	47610	2001	1997	0	-7,119.00	0	FALSE	0
2794	47610	2002	1997	0	-29,735.30	0	FALSE	0
2795	47610	2011	1997	8	20,081.35	0	FALSE	0
2796	47610	1999	1998	0	-2,442.50	0	FALSE	0
2797	47610	2000	1998	0	-8,142.80	0	FALSE	0
2798	47610	2001	1998	0	-9,076.70	0	FALSE	0
2799	47610	2002	1998	0	-21,884.00	0	FALSE	0
2800	47610	2011	1998	8	95,664.33	0	FALSE	0
2801	47610	1999	1999	0	-83.80	0	FALSE	0
2802	47610	2000	1999	0	-1,596.10	0	FALSE	0
2803	47610	2001	1999	0	-1,159.00	0	FALSE	0
2804	47610	2002	1999	0	-1,043.00	0	FALSE	0
2805	47610	2011	1999	8	71,622.77	0	FALSE	0
2806	47610	2000	2000	0	-488.10	0	FALSE	0
2807	47610	2001	2000	0	-1,709.40	0	FALSE	0
2808	47610	2002	2000	0	-407.90	0	FALSE	0

2809	47610	2005	2000	0	-1,699.10	0	FALSE	0
2810	47610	2006	2000	0	-20,979.10	0	FALSE	0
2811	47610	2010	2000	0	-16,542.80	0	FALSE	0
2812	47610	2011	2000	8	110,805.59	0	FALSE	0
2813	47610	2001	2001	0	-2,932.10	0	FALSE	0
2814	47610	2002	2001	0	-246.90	0	FALSE	0
2815	47610	2005	2001	0	-1,342.50	0	FALSE	0
2816	47610	2006	2001	0	-1,773.00	0	FALSE	0
2817	47610	2010	2001	0	-6,712.70	0	FALSE	0
2818	47610	2011	2001	8	38,275.23	0	FALSE	0
2819	47610	2005	2002	0	-1,386.50	0	FALSE	0
2820	47610	2006	2002	0	-512.90	0	FALSE	0
2821	47610	2010	2002	0	-8,596.90	0	FALSE	0
2822	47610	2011	2002	0	-15,455.60	0	FALSE	0
2823	47610	2011	2002	8	38,701.01	0	FALSE	0
2824	47610	2005	2003	0	-435.90	0	FALSE	0
2825	47610	2006	2003	0	-290.50	0	FALSE	0
2826	47610	2010	2003	0	-6,746.20	0	FALSE	0
2827	47610	2011	2003	0	-14,035.50	0	FALSE	0
2828	47610	2011	2003	8	109,974.70	0	FALSE	0
2829	47610	2005	2004	0	-43.50	0	FALSE	0
2830	47610	2006	2004	0	-262.00	0	FALSE	0
2831	47610	2010	2004	0	-5,176.10	0	FALSE	0
2832	47610	2011	2004	0	-371.20	0	FALSE	0
2833	47610	2011	2004	8	120,520.80	0	FALSE	0
2834	47610	2008	2005	0	-22,576.80	0	FALSE	0
2835	47610	2008	2005	3	-48.10	2005	FALSE	0
2836	47610	2011	2005	8	15,995.63	0	FALSE	0
2837	47610	2008	2006	0	-69,109.10	0	FALSE	0
2838	47610	2011	2006	8	8,685.31	0	FALSE	0
2839	47610	2008	2007	0	-4,810.00	0	FALSE	0
2840	47610	2008	2007	4	579.21	2007	FALSE	0
2841	47610	2009	2007	4	44.90	0	FALSE	0
2842	47610	2010	2007	0	-2,795.10	0	FALSE	0
2843	47610	2010	2007	3	-413.50	0	FALSE	0
2844	47610	2011	2007	0	-7,293.40	0	FALSE	0
2845	47610	2011	2007	3	-1.50	2007	FALSE	0
2846	47610	2011	2007	8	39,317.09	0	FALSE	0
2847	47610	2009	2008	4	64.57	0	FALSE	0
2848	47610	2011	2008	4	10,601.57	2008	FALSE	0
2849	47610	2011	2008	8	18,765.20	0	FALSE	0
2850	47610	2010	2009	4	3,923.81	0	FALSE	0
2851	47610	2011	2009	4	15.47	2009	FALSE	0
2852	47610	2011	2009	8	15,676.06	0	FALSE	0
2853	47610	2011	2010	0	-2,246.60	0	FALSE	0
2854	47610	2011	2010	4	3,069.20	2010	FALSE	0
2855	47610	2011	2010	8	482,401.74	0	FALSE	0
2856	47610	2011	2011	8	235,141.02	0	FALSE	0
2857	47630	2007	2007	0	-14,524.50	0	FALSE	0
2858	47630	2008	2007	3	-327.40	2007	FALSE	0
2859	47630	2009	2007	4	43.23	0	FALSE	0
2860	47630	2010	2007	4	38.38	0	FALSE	0
2861	47630	2011	2007	8	7,789.88	0	FALSE	0

2862	47630	2009	2008	4	4,466.25	0	FALSE	0
2863	47630	2010	2008	3	-401.20	0	FALSE	0
2864	47630	2011	2008	8	29,425.21	0	FALSE	0
2865	47630	2010	2009	3	-473.30	0	FALSE	0
2866	47630	2011	2009	8	11,869.27	0	FALSE	0
2867	47630	2011	2010	4	805.78	2010	FALSE	0
2868	47630	2011	2010	8	12,710.93	0	FALSE	0
2869	47630	2011	2011	8	5,851.04	0	FALSE	0
2870	47710	2011	1960	8	3,631.70	0	FALSE	0
2871	47710	2011	1968	8	16,606.00	0	FALSE	0
2872	47710	2011	1969	8	882.00	0	FALSE	0
2873	47710	1985	1970	0	-81.80	0	FALSE	0
2874	47710	1986	1971	0	-8.20	0	FALSE	0
2875	47710	2011	1971	8	39,959.05	0	FALSE	0
2876	47710	1988	1972	0	-1,110.50	0	FALSE	0
2877	47710	1990	1972	0	-176.00	0	FALSE	0
2878	47710	2011	1972	8	2,089.52	0	FALSE	0
2879	47710	2011	1973	8	56,550.00	0	FALSE	0
2880	47710	1988	1974	0	-6,115.80	0	FALSE	0
2881	47710	1990	1974	0	-71.50	0	FALSE	0
2882	47710	2011	1974	8	446.22	0	FALSE	0
2883	47710	1987	1975	0	-1,597.50	0	FALSE	0
2884	47710	1990	1976	0	-150.70	0	FALSE	0
2885	47710	2011	1976	8	333,091.33	0	FALSE	0
2886	47710	1986	1977	0	-1,571.80	0	FALSE	0
2887	47710	2011	1977	8	70,884.17	0	FALSE	0
2888	47710	2011	1979	8	14,954.00	0	FALSE	0
2889	47710	1989	1980	0	-1,929.20	0	FALSE	0
2890	47710	1990	1980	0	-6,207.10	0	FALSE	0
2891	47710	2011	1980	8	80,834.73	0	FALSE	0
2892	47710	1990	1981	0	-714.20	0	FALSE	0
2893	47710	2011	1981	8	126,329.84	0	FALSE	0
2894	47710	1986	1985	0	-211.00	0	FALSE	0
2895	47710	1990	1985	0	-574.10	0	FALSE	0
2896	47710	1991	1985	0	-722.80	0	FALSE	0
2897	47710	1997	1985	0	-40.00	0	FALSE	0
2898	47710	2011	1985	8	43,522.68	0	FALSE	0
2899	47710	1990	1986	0	-786.30	0	FALSE	0
2900	47710	1991	1986	0	-1,608.30	0	FALSE	0
2901	47710	2011	1986	8	118,315.85	0	FALSE	0
2902	47710	1990	1987	0	-7,648.50	0	FALSE	0
2903	47710	2011	1987	8	335,797.16	0	FALSE	0
2904	47710	1990	1988	0	-5,152.30	0	FALSE	0
2905	47710	2011	1988	8	60,907.24	0	FALSE	0
2906	47710	2011	1989	8	36,582.03	0	FALSE	0
2907	47710	2011	1990	8	132,200.60	0	FALSE	0
2908	47710	2011	1991	8	259,920.34	0	FALSE	0
2909	47710	1993	1992	4	19.27	1992	FALSE	0
2910	47710	2001	1992	3	-231,307.70	1992	FALSE	0
2911	47710	2011	1992	8	98,578.56	0	FALSE	0
2912	47710	1996	1993	4	117,325.21	1993	FALSE	0
2913	47710	2011	1993	8	166,934.17	0	FALSE	0
2914	47710	1994	1994	4	17,472.10	1994	FALSE	0

2915	47710	2011	1994	8	41,680.13	0	FALSE	0
2916	47710	2011	1996	8	196,092.49	0	FALSE	0
2917	47710	2001	1997	3	-93,710.30	1997	FALSE	0
2918	47710	2011	1997	8	1,451.70	0	FALSE	0
2919	47710	2011	1999	8	46,617.77	0	FALSE	0
2920	47710	2011	2000	8	79,093.83	0	FALSE	0
2921	47710	2011	2001	8	253,074.36	0	FALSE	0
2922	47710	2011	2005	8	491,706.97	0	FALSE	0
2923	47710	2011	2006	8	22,338.61	0	FALSE	0
2924	47810	1966	1957	0	-212.00	0	FALSE	0
2925	47810	1976	1957	0	-1,704.00	0	FALSE	0
2926	47810	1980	1957	0	-87.00	0	FALSE	0
2927	47810	1989	1957	0	0.00	0	FALSE	0
2928	47810	1958	1958	0	-1,261.00	0	FALSE	0
2929	47810	1961	1958	0	-1,388.00	0	FALSE	0
2930	47810	1971	1958	0	-330.00	0	FALSE	0
2931	47810	1975	1958	0	-493.00	0	FALSE	0
2932	47810	1980	1958	0	-53.00	0	FALSE	0
2933	47810	1960	1959	0	-123.00	0	FALSE	0
2934	47810	1962	1959	0	-95.00	0	FALSE	0
2935	47810	1964	1959	0	-924.00	0	FALSE	0
2936	47810	1965	1959	0	-425.00	0	FALSE	0
2937	47810	1974	1959	0	-326.00	0	FALSE	0
2938	47810	1977	1959	0	-35.00	0	FALSE	0
2939	47810	1963	1960	0	-208.00	0	FALSE	0
2940	47810	1973	1960	0	-380.00	0	FALSE	0
2941	47810	1974	1960	0	-18.00	0	FALSE	0
2942	47810	1977	1960	0	-258.00	0	FALSE	0
2943	47810	1978	1960	0	-5.00	0	FALSE	0
2944	47810	1980	1960	0	-1,203.00	0	FALSE	0
2945	47810	1964	1961	0	-63.00	0	FALSE	0
2946	47810	1976	1961	0	-242.00	0	FALSE	0
2947	47810	1977	1961	0	-292.00	0	FALSE	0
2948	47810	1980	1961	0	-4,189.00	0	FALSE	0
2949	47810	1981	1961	0	-699.00	0	FALSE	0
2950	47810	1987	1961	0	-3,302.00	0	FALSE	0
2951	47810	1970	1962	0	-278.00	0	FALSE	0
2952	47810	1977	1962	0	-4,306.00	0	FALSE	0
2953	47810	1981	1962	0	-801.00	0	FALSE	0
2954	47810	1986	1962	0	-2,507.00	0	FALSE	0
2955	47810	1987	1962	0	-1,248.70	0	FALSE	0
2956	47810	1969	1963	0	-3,929.00	0	FALSE	0
2957	47810	1970	1963	0	-293.00	0	FALSE	0
2958	47810	1971	1963	0	-3,037.00	0	FALSE	0
2959	47810	1972	1963	0	-1,496.00	0	FALSE	0
2960	47810	1975	1963	0	-929.00	0	FALSE	0
2961	47810	1979	1963	0	-836.00	0	FALSE	0
2962	47810	1987	1963	0	-5,793.00	0	FALSE	0
2963	47810	1969	1964	0	-767.00	0	FALSE	0
2964	47810	1971	1964	0	-580.00	0	FALSE	0
2965	47810	1973	1964	0	-2,439.00	0	FALSE	0
2966	47810	1975	1964	0	-2,282.00	0	FALSE	0
2967	47810	1977	1964	0	-363.00	0	FALSE	0

2968	47810	1987	1964	0	-8,581.00	0	FALSE	0
2969	47810	1969	1965	0	-1,016.00	0	FALSE	0
2970	47810	1977	1965	0	-293.00	0	FALSE	0
2971	47810	1985	1965	0	-329.00	0	FALSE	0
2972	47810	1987	1965	0	-4,588.80	0	FALSE	0
2973	47810	1969	1966	0	-156.00	0	FALSE	0
2974	47810	1971	1966	0	-806.00	0	FALSE	0
2975	47810	1977	1966	0	-271.00	0	FALSE	0
2976	47810	1978	1966	0	-1,007.00	0	FALSE	0
2977	47810	1987	1966	0	-4,268.00	0	FALSE	0
2978	47810	1967	1967	0	-10.00	0	FALSE	0
2979	47810	1987	1967	0	-938.00	0	FALSE	0
2980	47810	1972	1968	0	-30.00	0	FALSE	0
2981	47810	1974	1968	0	-1,463.00	0	FALSE	0
2982	47810	1978	1968	0	-59.00	0	FALSE	0
2983	47810	1987	1968	0	-23,179.00	0	FALSE	0
2984	47810	1977	1969	0	-1,216.00	0	FALSE	0
2985	47810	1987	1969	0	-61,860.00	0	FALSE	0
2986	47810	1974	1970	0	-131.00	0	FALSE	0
2987	47810	1977	1970	0	-1,306.00	0	FALSE	0
2988	47810	1983	1970	0	-1,007.00	0	FALSE	0
2989	47810	1984	1970	0	-814.00	0	FALSE	0
2990	47810	1987	1970	0	-30,505.00	0	FALSE	0
2991	47810	1977	1971	0	-318.00	0	FALSE	0
2992	47810	1986	1971	0	-548.00	0	FALSE	0
2993	47810	1987	1971	0	-15,530.00	0	FALSE	0
2994	47810	1983	1972	0	-5,184.00	0	FALSE	0
2995	47810	1984	1972	0	-642.00	0	FALSE	0
2996	47810	1987	1972	0	-36,942.00	0	FALSE	0
2997	47810	1987	1973	0	-15,005.00	0	FALSE	0
2998	47810	1981	1974	0	-6.00	0	FALSE	0
2999	47810	1987	1974	0	-33,300.00	0	FALSE	0
3000	47810	1988	1974	0	-5,125.00	0	FALSE	0
3001	47810	1991	1974	0	-424.40	0	FALSE	0
3002	47810	1992	1974	0	-1,782.70	0	FALSE	0
3003	47810	1993	1974	0	-1,303.60	0	FALSE	0
3004	47810	1994	1974	0	-1,391.50	0	FALSE	0
3005	47810	1997	1974	0	-2,258.00	0	FALSE	0
3006	47810	2000	1974	0	-123.40	0	FALSE	0
3007	47810	2002	1974	0	-127.40	0	FALSE	0
3008	47810	2006	1974	0	-131.00	0	FALSE	0
3009	47810	2011	1974	8	4,057.78	0	FALSE	0
3010	47810	1988	1975	0	-5,436.00	0	FALSE	0
3011	47810	1991	1975	0	-8.80	0	FALSE	0
3012	47810	1992	1975	0	-893.10	0	FALSE	0
3013	47810	1993	1975	0	-0.70	0	FALSE	0
3014	47810	1994	1975	0	-180.00	0	FALSE	0
3015	47810	1997	1975	0	-126.70	0	FALSE	0
3016	47810	1998	1975	0	-631.60	0	FALSE	0
3017	47810	2000	1975	0	-1,684.20	0	FALSE	0
3018	47810	2004	1975	0	-319.70	0	FALSE	0
3019	47810	2011	1975	8	230.46	0	FALSE	0
3020	47810	1981	1976	0	-13.00	0	FALSE	0

3021	47810	1982	1976	0	-19,004.00	0	FALSE	0
3022	47810	1985	1976	0	-4,837.00	0	FALSE	0
3023	47810	1986	1976	0	-878.00	0	FALSE	0
3024	47810	1987	1976	0	-50,197.00	0	FALSE	0
3025	47810	1988	1976	0	-2,451.00	0	FALSE	0
3026	47810	1978	1977	0	-320.00	0	FALSE	0
3027	47810	1981	1977	0	-364.00	0	FALSE	0
3028	47810	1982	1977	0	-420.00	0	FALSE	0
3029	47810	1985	1977	0	-4,715.00	0	FALSE	0
3030	47810	1986	1977	0	-8,887.00	0	FALSE	0
3031	47810	1987	1977	0	-33,213.80	0	FALSE	0
3032	47810	1988	1977	0	-6,290.00	0	FALSE	0
3033	47810	1989	1977	0	-1,935.00	0	FALSE	0
3034	47810	1990	1977	0	-3,916.00	0	FALSE	0
3035	47810	1992	1977	0	-45.10	0	FALSE	0
3036	47810	2008	1977	0	-237.00	0	FALSE	0
3037	47810	2009	1977	0	-76.10	0	FALSE	0
3038	47810	2010	1977	0	-99.00	0	FALSE	0
3039	47810	2011	1977	8	42,389.29	0	FALSE	0
3040	47810	1983	1978	0	-25.00	0	FALSE	0
3041	47810	1986	1978	0	-38.00	0	FALSE	0
3042	47810	1987	1978	0	-102,533.00	0	FALSE	0
3043	47810	1988	1978	0	-13,350.00	0	FALSE	0
3044	47810	1989	1978	0	-3,684.00	0	FALSE	0
3045	47810	2011	1978	8	22,260.89	0	FALSE	0
3046	47810	1984	1979	0	-1,749.00	0	FALSE	0
3047	47810	1987	1979	0	-1,930.00	0	FALSE	0
3048	47810	1989	1979	0	0.00	0	FALSE	0
3049	47810	1992	1979	0	-493.50	0	FALSE	0
3050	47810	1994	1979	0	-38.10	0	FALSE	0
3051	47810	2006	1979	0	-4,067.00	0	FALSE	0
3052	47810	2008	1979	0	-726.00	0	FALSE	0
3053	47810	2009	1979	0	-2,119.00	0	FALSE	0
3054	47810	2010	1979	0	-4,846.10	0	FALSE	0
3055	47810	2011	1979	0	-165.00	0	FALSE	0
3056	47810	2011	1979	8	15,471.24	0	FALSE	0
3057	47810	1989	1980	0	0.00	0	FALSE	0
3058	47810	1997	1980	0	-881.60	0	FALSE	0
3059	47810	1998	1980	0	-1,063.90	0	FALSE	0
3060	47810	1999	1980	0	-1,063.90	0	FALSE	0
3061	47810	2000	1980	0	-384.50	0	FALSE	0
3062	47810	2001	1980	0	-11,919.10	0	FALSE	0
3063	47810	2005	1980	0	-2,788.90	0	FALSE	0
3064	47810	2006	1980	0	-1,104.00	0	FALSE	0
3065	47810	2007	1980	0	-4,492.90	0	FALSE	0
3066	47810	2011	1980	8	184,650.87	0	FALSE	0
3067	47810	1986	1981	0	-682.00	0	FALSE	0
3068	47810	1987	1981	0	-320.00	0	FALSE	0
3069	47810	1989	1981	0	0.00	0	FALSE	0
3070	47810	1997	1981	0	-185.90	0	FALSE	0
3071	47810	1998	1981	0	-419.90	0	FALSE	0
3072	47810	2011	1981	8	28,488.46	0	FALSE	0
3073	47810	1983	1982	0	-64.00	0	FALSE	0

3074	47810	1989	1982	0	-27,781.00	0	FALSE	0
3075	47810	2011	1982	8	69,549.87	0	FALSE	0
3076	47810	1987	1983	0	-25.60	0	FALSE	0
3077	47810	2011	1983	8	113,988.36	0	FALSE	0
3078	47810	1988	1984	0	-6,551.00	0	FALSE	0
3079	47810	1990	1984	0	-626.40	0	FALSE	0
3080	47810	1994	1984	0	-122.30	0	FALSE	0
3081	47810	2011	1984	8	98,481.92	0	FALSE	0
3082	47810	1991	1985	0	-272.10	0	FALSE	0
3083	47810	1997	1985	0	-12,144.00	0	FALSE	0
3084	47810	1998	1985	0	-940.80	0	FALSE	0
3085	47810	2000	1985	0	-5,079.70	0	FALSE	0
3086	47810	2010	1985	0	-2,343.00	0	FALSE	0
3087	47810	2011	1985	8	29,194.06	0	FALSE	0
3088	47810	2011	1986	8	348,615.98	0	FALSE	0
3089	47810	1997	1987	0	-328.90	0	FALSE	0
3090	47810	1999	1987	0	-2,502.10	0	FALSE	0
3091	47810	2011	1987	8	137,151.99	0	FALSE	0
3092	47810	1996	1988	0	-3,797.30	0	FALSE	0
3093	47810	1997	1988	0	-191.90	0	FALSE	0
3094	47810	1998	1988	0	-656.40	0	FALSE	0
3095	47810	2011	1988	8	209,962.68	0	FALSE	0
3096	47810	2011	1989	8	572,762.96	0	FALSE	0
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3099	47810	1999	1990	0	-483.40	0	FALSE	0
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3105	47810	2011	1991	8	222,337.62	0	FALSE	0
3106	47810	2011	1992	8	89,796.68	0	FALSE	0
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3108	47810	1994	1993	4	471.76	1993	FALSE	0
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3112	47810	1998	1995	0	-843.80	0	FALSE	0
3113	47810	2003	1995	0	-4,371.00	0	FALSE	0
3114	47810	2003	1995	0	-4,371.00	0	FALSE	0
3115	47810	2011	1995	8	310,528.34	0	FALSE	0
3116	47810	2011	1996	8	107,223.57	0	FALSE	0
3117	47810	2011	1997	8	413,878.23	0	FALSE	0
3118	47810	2011	1998	8	217,759.97	0	FALSE	0
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3121	47810	2011	2000	8	210,200.54	0	FALSE	0
3122	47810	2011	2001	8	356,557.44	0	FALSE	0
3123	47810	2003	2002	0	-4,862.20	0	FALSE	0
3124	47810	2004	2002	0	-11,062.80	0	FALSE	0
3125	47810	2011	2002	8	195,535.23	0	FALSE	0
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3128	47810	2011	2004	8	504,727.00	0	FALSE	0
3129	47810	2011	2005	8	109,056.61	0	FALSE	0
3130	47810	2006	2006	4	38.97	0	FALSE	0
3131	47810	2008	2006	3	-1,591.80	2006	FALSE	0
3132	47810	2011	2006	8	799,992.38	0	FALSE	0
3133	47810	2008	2007	3	-28,268.50	2007	FALSE	0
3134	47810	2009	2007	3	-612.20	0	FALSE	0
3135	47810	2010	2007	3	-86.00	0	FALSE	0
3136	47810	2011	2007	8	524,616.74	0	FALSE	0
3137	47810	2009	2008	4	16,205.89	0	FALSE	0
3138	47810	2010	2008	4	1,378.70	0	FALSE	0
3139	47810	2011	2008	8	217,945.03	0	FALSE	0
3140	47810	2010	2009	4	51,407.44	0	FALSE	0
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3142	47810	2011	2010	4	10,697.58	2010	FALSE	0
3143	47810	2011	2010	8	196,401.93	0	FALSE	0
3144	47810	2011	2011	8	497,158.76	0	FALSE	0
3145	47820	1968	1963	0	-157.00	0	FALSE	0
3146	47820	1980	1963	0	-55.00	0	FALSE	0
3147	47820	1972	1964	0	-113.00	0	FALSE	0
3148	47820	1974	1964	0	-300.00	0	FALSE	0
3149	47820	1980	1964	0	-2,191.00	0	FALSE	0
3150	47820	1985	1964	0	-2,601.00	0	FALSE	0
3151	47820	1986	1964	0	-4,964.00	0	FALSE	0
3152	47820	1969	1965	0	-1,359.00	0	FALSE	0
3153	47820	1986	1965	0	-2,494.00	0	FALSE	0
3154	47820	1987	1965	0	-11.00	0	FALSE	0
3155	47820	1967	1966	0	-230.00	0	FALSE	0
3156	47820	1968	1966	0	-168.00	0	FALSE	0
3157	47820	1987	1966	0	-2,666.00	0	FALSE	0
3158	47820	1968	1967	0	-392.00	0	FALSE	0
3159	47820	1972	1967	0	-316.00	0	FALSE	0
3160	47820	1983	1967	0	-3,635.00	0	FALSE	0
3161	47820	1987	1967	0	-374.00	0	FALSE	0
3162	47820	1988	1967	0	-2,486.00	0	FALSE	0
3163	47820	1989	1967	0	-565.00	0	FALSE	0
3164	47820	1992	1967	0	-407.30	0	FALSE	0
3165	47820	2011	1967	8	2,516.28	0	FALSE	0
3166	47820	1979	1968	0	-907.00	0	FALSE	0
3167	47820	1983	1968	0	-5,706.00	0	FALSE	0
3168	47820	1970	1969	0	-510.00	0	FALSE	0
3169	47820	1971	1969	0	-2,464.00	0	FALSE	0
3170	47820	1972	1969	0	-90.00	0	FALSE	0
3171	47820	1979	1969	0	-2,152.00	0	FALSE	0
3172	47820	1975	1970	0	-3,064.00	0	FALSE	0
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3175	47820	1976	1971	0	-5,662.00	0	FALSE	0
3176	47820	1977	1971	0	-3,074.00	0	FALSE	0
3177	47820	1978	1971	0	-7,104.00	0	FALSE	0
3178	47820	1979	1971	0	-5,156.00	0	FALSE	0
3179	47820	1973	1972	0	-2,390.00	0	FALSE	0

3180	47820	1974	1972	0	-3,073.00	0	FALSE	0
3181	47820	1982	1972	0	-2,960.00	0	FALSE	0
3182	47820	1981	1973	0	-6,477.00	0	FALSE	0
3183	47820	1982	1973	0	-2,479.00	0	FALSE	0
3184	47820	1984	1973	0	-4,476.00	0	FALSE	0
3185	47820	2011	1973	8	1,471.00	0	FALSE	0
3186	47820	2011	1974	8	19,675.00	0	FALSE	0
3187	47820	2011	1975	8	4,754.00	0	FALSE	0
3188	47820	1992	1976	0	-152.20	0	FALSE	0
3189	47820	2011	1976	8	14,852.76	0	FALSE	0
3190	47820	2011	1977	8	10,540.00	0	FALSE	0
3191	47820	2011	1978	8	16,073.00	0	FALSE	0
3192	47820	2011	1979	8	29,321.00	0	FALSE	0
3193	47820	2011	1980	8	18,970.00	0	FALSE	0
3194	47820	2011	1981	8	17,037.00	0	FALSE	0
3195	47820	2011	1982	8	9,135.00	0	FALSE	0
3196	47820	2011	1983	8	10,835.00	0	FALSE	0
3197	47820	1994	1984	0	-935.80	0	FALSE	0
3198	47820	1995	1984	0	-83.20	0	FALSE	0
3199	47820	2011	1984	8	19,067.94	0	FALSE	0
3200	47820	2011	1985	8	10,529.38	0	FALSE	0
3201	47820	2011	1986	8	31,912.79	0	FALSE	0
3202	47820	2011	1987	8	14,211.05	0	FALSE	0
3203	47820	2011	1988	8	13,496.10	0	FALSE	0
3204	47820	2011	1989	8	7,391.51	0	FALSE	0
3205	47820	2011	1990	8	3,329.07	0	FALSE	0
3206	47820	2011	1991	8	2,562.75	0	FALSE	0
3207	47820	2011	1992	8	10,584.67	0	FALSE	0
3208	47820	2011	1993	8	152.13	0	FALSE	0
3209	47820	2011	1997	8	15,872.16	0	FALSE	0
3210	47820	2011	1999	8	448.69	0	FALSE	0
3211	47910	1962	1945	0	-109.00	0	FALSE	0
3212	47910	1963	1945	0	-186.00	0	FALSE	0
3213	47910	1967	1945	0	-2,560.00	0	FALSE	0
3214	47910	1968	1945	0	-356.00	0	FALSE	0
3215	47910	1970	1945	0	-103.00	0	FALSE	0
3216	47910	1980	1945	0	-3,313.00	0	FALSE	0
3217	47910	1970	1946	0	-497.00	0	FALSE	0
3218	47910	1980	1946	0	-497.00	0	FALSE	0
3219	47910	1985	1946	4	1,885.00	1946	FALSE	0
3220	47910	1990	1946	0	-239.50	0	FALSE	0
3221	47910	1991	1946	0	-2,235.50	0	FALSE	0
3222	47910	2011	1946	8	226.33	0	FALSE	0
3223	47910	1970	1947	0	-572.00	0	FALSE	0
3224	47910	1980	1947	0	-571.00	0	FALSE	0
3225	47910	1986	1947	4	806.00	1947	FALSE	0
3226	47910	1997	1947	0	-1,150.00	0	FALSE	0
3227	47910	2011	1947	8	1,242.88	0	FALSE	0
3228	47910	1970	1948	0	-571.00	0	FALSE	0
3229	47910	1971	1948	0	-87.00	0	FALSE	0
3230	47910	1980	1948	0	-657.00	0	FALSE	0
3231	47910	2005	1948	0	-1,343.20	0	FALSE	0
3232	47910	2011	1948	8	1,616.79	0	FALSE	0

3233	47910	1971	1949	0	-756.00	0		FALSE	0
3234	47910	1980	1949	0	-751.00	0		FALSE	0
3235	47910	1971	1950	0	-870.00	0		FALSE	0
3236	47910	1995	1950	0	-145.00	0		FALSE	0
3237	47910	2005	1950	0	-694.90	0		FALSE	0
3238	47910	2011	1950	8	28.96	0		FALSE	0
3239	47910	1971	1951	0	-1,001.00	0		FALSE	0
3240	47910	1985	1951	4	2,955.00	1951		FALSE	0
3241	47910	1985	1951	4	11,835.00	1951		FALSE	0
3242	47910	1990	1951	4	-1,900.00	1951	Correction 1168500	FALSE	0
3243	47910	1990	1951	4	2,921.25	1951	Correction 1168500	FALSE	0
3244	47910	2005	1951	0	-9,004.90	0		FALSE	0
3245	47910	2006	1951	0	-16.10	0		FALSE	0
3246	47910	2011	1951	8	15,498.02	0		FALSE	0
3247	47910	1971	1952	0	-1,534.00	0		FALSE	0
3248	47910	1985	1952	4	100.00	1952		FALSE	0
3249	47910	1985	1952	4	7,578.00	1952		FALSE	0
3250	47910	1990	1952	4	2,921.25	1952	Correction 1168500	FALSE	0
3251	47910	1992	1952	0	-6,210.00	0		FALSE	0
3252	47910	1992	1952	4	18,000.00	1952		FALSE	0
3253	47910	2011	1952	8	20,900.00	0		FALSE	0
3254	47910	1971	1953	0	-2,761.00	0		FALSE	0
3255	47910	1985	1953	4	2,758.00	1953		FALSE	0
3256	47910	1990	1953	4	-200.00	1953	Correction 1168500	FALSE	0
3257	47910	1990	1953	4	2,921.25	1953	Correction 1168500	FALSE	0
3258	47910	2011	1953	8	2,758.00	0		FALSE	0
3259	47910	1971	1954	0	-3,590.00	0		FALSE	0
3260	47910	1985	1954	4	1,930.00	1954		FALSE	0
3261	47910	1990	1954	4	200.00	1954	Correction 1168500	FALSE	0
3262	47910	1990	1954	4	1,900.00	1954	Correction 1168500	FALSE	0
3263	47910	1990	1954	4	2,921.25	1954	Correction 1168500	FALSE	0
3264	47910	1995	1954	0	-61.60	0		FALSE	0
3265	47910	2011	1954	8	5,453.44	0		FALSE	0
3266	47910	1971	1955	0	-3,111.00	0		FALSE	0
3267	47910	1985	1955	4	19,550.00	1955		FALSE	0
3268	47910	1991	1955	0	-298.00	0		FALSE	0
3269	47910	2004	1955	0	-191.60	0		FALSE	0
3270	47910	2010	1955	0	-841.00	0		FALSE	0
3271	47910	2011	1955	8	21,326.43	0		FALSE	0
3272	47910	1971	1956	0	-2,762.00	0		FALSE	0
3273	47910	1972	1956	0	-810.00	0		FALSE	0
3274	47910	1974	1956	0	-160.00	0		FALSE	0
3275	47910	2011	1956	8	3,729.00	0		FALSE	0
3276	47910	1974	1957	0	-2,417.00	0		FALSE	0
3277	47910	1975	1957	0	-1,450.00	0		FALSE	0
3278	47910	1976	1957	0	-614.00	0		FALSE	0
3279	47910	1977	1957	0	-340.00	0		FALSE	0
3280	47910	1978	1957	0	-4,133.00	0		FALSE	0
3281	47910	1969	1958	0	-431.00	0		FALSE	0
3282	47910	1970	1958	0	-132.00	0		FALSE	0
3283	47910	1972	1958	0	-446.00	0		FALSE	0
3284	47910	1978	1958	0	-5,778.00	0		FALSE	0
3285	47910	1985	1958	4	773.00	1958		FALSE	0

3286	47910	2011	1958	8	2,255.00	0	FALSE	0
3287	47910	1960	1959	0	-500.00	0	FALSE	0
3288	47910	1963	1959	0	-99.00	0	FALSE	0
3289	47910	1965	1959	0	-570.00	0	FALSE	0
3290	47910	1968	1959	0	-280.00	0	FALSE	0
3291	47910	1970	1959	0	-642.00	0	FALSE	0
3292	47910	1971	1959	0	-134.00	0	FALSE	0
3293	47910	1973	1959	0	-743.00	0	FALSE	0
3294	47910	1974	1959	0	-390.00	0	FALSE	0
3295	47910	1977	1959	0	-6,862.00	0	FALSE	0
3296	47910	1981	1959	0	-493.00	0	FALSE	0
3297	47910	1991	1959	0	-367.00	0	FALSE	0
3298	47910	2011	1959	8	18,726.00	0	FALSE	0
3299	47910	1960	1960	0	-45.00	0	FALSE	0
3300	47910	1961	1960	0	-142.00	0	FALSE	0
3301	47910	1965	1960	0	-171.00	0	FALSE	0
3302	47910	1967	1960	0	-191.00	0	FALSE	0
3303	47910	1968	1960	0	-264.00	0	FALSE	0
3304	47910	1969	1960	0	-1,179.00	0	FALSE	0
3305	47910	1970	1960	0	-823.00	0	FALSE	0
3306	47910	1973	1960	0	-1,042.00	0	FALSE	0
3307	47910	1975	1960	0	-378.00	0	FALSE	0
3308	47910	1976	1960	0	-155.00	0	FALSE	0
3309	47910	1978	1960	0	-2,237.00	0	FALSE	0
3310	47910	1986	1960	4	592.00	1960	FALSE	0
3311	47910	1995	1960	0	-43.40	0	FALSE	0
3312	47910	2000	1960	0	-380.50	0	FALSE	0
3313	47910	2011	1960	8	37,058.01	0	FALSE	0
3314	47910	1961	1961	0	-458.00	0	FALSE	0
3315	47910	1964	1961	0	-175.00	0	FALSE	0
3316	47910	1965	1961	0	-132.00	0	FALSE	0
3317	47910	1969	1961	0	-431.00	0	FALSE	0
3318	47910	1970	1961	0	-384.00	0	FALSE	0
3319	47910	1972	1961	0	-298.00	0	FALSE	0
3320	47910	1973	1961	0	-16.00	0	FALSE	0
3321	47910	1976	1961	0	-58.00	0	FALSE	0
3322	47910	1977	1961	0	-229.00	0	FALSE	0
3323	47910	1978	1961	0	-39.00	0	FALSE	0
3324	47910	2011	1961	8	10,822.00	0	FALSE	0
3325	47910	1963	1962	0	-119.00	0	FALSE	0
3326	47910	1970	1962	0	-75.00	0	FALSE	0
3327	47910	1971	1962	0	-1,542.00	0	FALSE	0
3328	47910	1972	1962	0	-148.00	0	FALSE	0
3329	47910	1973	1962	0	-119.00	0	FALSE	0
3330	47910	1975	1962	0	-602.00	0	FALSE	0
3331	47910	1976	1962	0	-123.00	0	FALSE	0
3332	47910	1977	1962	0	-6.00	0	FALSE	0
3333	47910	1991	1962	0	-620.00	0	FALSE	0
3334	47910	2011	1962	8	9,436.00	0	FALSE	0
3335	47910	1965	1963	0	-83.00	0	FALSE	0
3336	47910	1975	1963	0	-196.00	0	FALSE	0
3337	47910	1978	1963	0	-128.00	0	FALSE	0
3338	47910	1979	1963	0	-218.00	0	FALSE	0

3339	47910	2011	1963	8	24,530.00	0		FALSE	0
3340	47910	1969	1964	0	-410.00	0		FALSE	0
3341	47910	1971	1964	0	-164.00	0		FALSE	0
3342	47910	1972	1964	0	-434.00	0		FALSE	0
3343	47910	1973	1964	0	-164.00	0		FALSE	0
3344	47910	1978	1964	0	-350.00	0		FALSE	0
3345	47910	1991	1964	0	-308.00	0		FALSE	0
3346	47910	1995	1964	4	1,500.00	1964		FALSE	0
3347	47910	2011	1964	8	6,995.00	0		FALSE	0
3348	47910	1969	1965	0	-373.00	0		FALSE	0
3349	47910	1976	1965	0	-31.00	0		FALSE	0
3350	47910	1981	1965	0	-891.00	0		FALSE	0
3351	47910	1985	1965	0	-1,138.40	0		FALSE	0
3352	47910	1991	1965	0	-2,581.70	0		FALSE	0
3353	47910	1999	1965	0	-139.90	0		FALSE	0
3354	47910	2011	1965	8	13,727.00	0		FALSE	0
3355	47910	1967	1966	0	-750.00	0		FALSE	0
3356	47910	1971	1966	0	-256.00	0		FALSE	0
3357	47910	1972	1966	0	-11.00	0		FALSE	0
3358	47910	1973	1966	0	-10.00	0		FALSE	0
3359	47910	1975	1966	0	-323.00	0		FALSE	0
3360	47910	1978	1966	0	-38.00	0		FALSE	0
3361	47910	1991	1966	4	171.20	1966		FALSE	0
3362	47910	2011	1966	8	36,590.20	0		FALSE	0
3363	47910	1968	1967	0	-51.00	0		FALSE	0
3364	47910	1969	1967	0	-732.00	0		FALSE	0
3365	47910	1970	1967	0	-477.00	0		FALSE	0
3366	47910	1972	1967	0	-124.00	0		FALSE	0
3367	47910	1978	1967	0	-36.00	0		FALSE	0
3368	47910	1986	1967	4	351.00	1967		FALSE	0
3369	47910	2001	1967	0	-53.30	0		FALSE	0
3370	47910	2004	1967	0	-26.70	0		FALSE	0
3371	47910	2010	1967	0	-1,747.00	0		FALSE	0
3372	47910	2011	1967	8	62,470.06	0		FALSE	0
3373	47910	1969	1968	0	-1,803.00	0		FALSE	0
3374	47910	1970	1968	0	-499.00	0		FALSE	0
3375	47910	1971	1968	0	-52.00	0		FALSE	0
3376	47910	1972	1968	0	-3,961.00	0		FALSE	0
3377	47910	1973	1968	0	-2,241.00	0		FALSE	0
3378	47910	1975	1968	0	-361.00	0		FALSE	0
3379	47910	1977	1968	0	-28.00	0		FALSE	0
3380	47910	1978	1968	0	-350.00	0		FALSE	0
3381	47910	1981	1968	0	-100.00	0		FALSE	0
3382	47910	1986	1968	4	342.00	1968		FALSE	0
3383	47910	1988	1968	4	470.00	1968		FALSE	0
3384	47910	1991	1968	0	-1,916.90	0		FALSE	0
3385	47910	2001	1968	0	-252.60	0		FALSE	0
3386	47910	2005	1968	0	-88.90	0		FALSE	0
3387	47910	2006	1968	0	-101.00	0		FALSE	0
3388	47910	2008	1968	0	-884.00	0		FALSE	0
3389	47910	2009	1968	0	-31.00	0		FALSE	0
3390	47910	2010	1968	0	-317.10	0		FALSE	0
3391	47910	2011	1968	0	-366.00	0		FALSE	0

3392	47910	2011	1968	8	178,530.55	0		FALSE	0
3393	47910	1971	1969	0	-180.00	0		FALSE	0
3394	47910	1973	1969	0	-130.00	0		FALSE	0
3395	47910	1974	1969	0	-247.00	0		FALSE	0
3396	47910	1978	1969	0	-350.00	0		FALSE	0
3397	47910	1983	1969	0	-54.00	0		FALSE	0
3398	47910	1984	1969	0	-61.00	0		FALSE	0
3399	47910	1988	1969	4	470.00	1969		FALSE	0
3400	47910	1991	1969	0	-429.30	0		FALSE	0
3401	47910	1992	1969	0	-167.90	0		FALSE	0
3402	47910	1993	1969	0	-52.00	0		FALSE	0
3403	47910	1994	1969	0	-52.00	0		FALSE	0
3404	47910	1999	1969	0	-28.70	0		FALSE	0
3405	47910	2010	1969	0	-529.00	0		FALSE	0
3406	47910	2011	1969	0	-212.10	0		FALSE	0
3407	47910	2011	1969	8	37,843.96	0		FALSE	0
3408	47910	1971	1970	0	-238.00	0		FALSE	0
3409	47910	1973	1970	0	-270.00	0		FALSE	0
3410	47910	1978	1970	0	-36.00	0		FALSE	0
3411	47910	1983	1970	0	-827.00	0		FALSE	0
3412	47910	1984	1970	0	-1,092.00	0		FALSE	0
3413	47910	1987	1970	4	242.00	1970		FALSE	0
3414	47910	1992	1970	0	-8,959.40	0		FALSE	0
3415	47910	1993	1970	0	-922.50	0		FALSE	0
3416	47910	1994	1970	0	-1,001.20	0		FALSE	0
3417	47910	1996	1970	0	-490.20	0		FALSE	0
3418	47910	1998	1970	0	-553.80	0		FALSE	0
3419	47910	1999	1970	0	-94.30	0		FALSE	0
3420	47910	2000	1970	0	-325.80	0		FALSE	0
3421	47910	2001	1970	0	-785.30	0		FALSE	0
3422	47910	2002	1970	0	-90.40	0		FALSE	0
3423	47910	2003	1970	0	-261.80	0		FALSE	0
3424	47910	2003	1970	0	-261.80	0		FALSE	0
3425	47910	2003	1970	0	-44,674.80	0		FALSE	0
3426	47910	2003	1970	0	-9.20	0		FALSE	0
3427	47910	2003	1970	0	-9.20	0		FALSE	0
3428	47910	2003	1970	0	-9.20	0		FALSE	0
3429	47910	2003	1970	0	-9.20	0		FALSE	0
3430	47910	2003	1970	0	-9.20	0		FALSE	0
3431	47910	2003	1970	0	-9.20	0		FALSE	0
3432	47910	2003	1970	0	-9.20	0		FALSE	0
3433	47910	2005	1970	0	-209.00	0		FALSE	0
3434	47910	2007	1970	0	-129.00	0		FALSE	0
3435	47910	2008	1970	0	-70.00	0		FALSE	0
3436	47910	2009	1970	0	-35.00	0		FALSE	0
3437	47910	2010	1970	0	-3,797.00	0		FALSE	0
3438	47910	2011	1970	0	-231.10	0		FALSE	0
3439	47910	2011	1970	8	47,642.66	0		FALSE	0
3440	47910	1973	1971	0	-811.00	0		FALSE	0
3441	47910	1974	1971	0	-299.00	0		FALSE	0
3442	47910	1976	1971	0	-83.00	0		FALSE	0
3443	47910	1983	1971	0	-459.00	0		FALSE	0
3444	47910	1984	1971	0	-162.00	0		FALSE	0

3445	47910	1986	1971	4	256.00	1971		FALSE	0
3446	47910	1987	1971	4	242.00	1971		FALSE	0
3447	47910	1991	1971	0	-646.80	0		FALSE	0
3448	47910	1992	1971	0	-700.00	0		FALSE	0
3449	47910	1993	1971	0	-309.90	0		FALSE	0
3450	47910	1994	1971	0	-33.90	0		FALSE	0
3451	47910	1997	1971	0	-63.00	0		FALSE	0
3452	47910	2003	1971	0	-62.40	0		FALSE	0
3453	47910	2005	1971	0	-437.20	0		FALSE	0
3454	47910	2008	1971	0	-36.00	0		FALSE	0
3455	47910	2011	1971	8	67,977.76	0		FALSE	0
3456	47910	1975	1972	0	-185.00	0		FALSE	0
3457	47910	1977	1972	0	-62.00	0		FALSE	0
3458	47910	1978	1972	0	-350.00	0		FALSE	0
3459	47910	1979	1972	0	-264.00	0		FALSE	0
3460	47910	1980	1972	0	-61.00	0		FALSE	0
3461	47910	1983	1972	0	-370.00	0		FALSE	0
3462	47910	1984	1972	0	-486.00	0		FALSE	0
3463	47910	1991	1972	0	-1,442.00	0		FALSE	0
3464	47910	1992	1972	0	-14,403.10	0		FALSE	0
3465	47910	1993	1972	0	-344.00	0		FALSE	0
3466	47910	1994	1972	0	-344.00	0		FALSE	0
3467	47910	2003	1972	0	-33.70	0		FALSE	0
3468	47910	2005	1972	0	-179.10	0		FALSE	0
3469	47910	2009	1972	0	-280.00	0		FALSE	0
3470	47910	2010	1972	0	-673.00	0		FALSE	0
3471	47910	2011	1972	8	78,104.06	0		FALSE	0
3472	47910	1976	1973	0	-298.00	0		FALSE	0
3473	47910	1978	1973	0	-191.00	0		FALSE	0
3474	47910	1983	1973	0	-539.00	0		FALSE	0
3475	47910	1985	1973	0	-217.50	0		FALSE	0
3476	47910	1986	1973	0	-39.80	0		FALSE	0
3477	47910	1987	1973	4	277.00	1973		FALSE	0
3478	47910	1992	1973	0	-5,886.10	0		FALSE	0
3479	47910	1993	1973	0	-232.10	0		FALSE	0
3480	47910	1994	1973	0	-954.70	0		FALSE	0
3481	47910	2011	1973	8	67,293.83	0		FALSE	0
3482	47910	1981	1974	0	-990.00	0		FALSE	0
3483	47910	1986	1974	4	369.00	1974		FALSE	0
3484	47910	1992	1974	0	-980.00	0		FALSE	0
3485	47910	1993	1974	0	-546.00	0		FALSE	0
3486	47910	1994	1974	0	-440.30	0		FALSE	0
3487	47910	1995	1974	4	742.00	1974		FALSE	0
3488	47910	2008	1974	0	-569.00	0		FALSE	0
3489	47910	2009	1974	0	-104.00	0		FALSE	0
3490	47910	2010	1974	0	-502.00	0		FALSE	0
3491	47910	2011	1974	8	69,239.74	0		FALSE	0
3492	47910	1979	1975	0	-254.00	0		FALSE	0
3493	47910	1982	1975	0	-321.00	0		FALSE	0
3494	47910	1983	1975	0	-857.00	0		FALSE	0
3495	47910	1985	1975	0	-812.20	0		FALSE	0
3496	47910	1986	1975	0	-505.40	0		FALSE	0
3497	47910	1987	1975	0	-51.80	0		FALSE	0

3498	47910	1992	1975	0	-31,059.10	0	FALSE	0
3499	47910	1993	1975	0	-46.20	0	FALSE	0
3500	47910	1994	1975	0	-425.10	0	FALSE	0
3501	47910	1998	1975	0	-3,430.20	0	FALSE	0
3502	47910	2000	1975	0	-400.30	0	FALSE	0
3503	47910	2001	1975	0	-95.20	0	FALSE	0
3504	47910	2002	1975	0	-427.20	0	FALSE	0
3505	47910	2005	1975	0	-56.00	0	FALSE	0
3506	47910	2006	1975	0	-423.00	0	FALSE	0
3507	47910	2008	1975	0	-56.00	0	FALSE	0
3508	47910	2009	1975	0	-113.00	0	FALSE	0
3509	47910	2011	1975	0	-3,229.00	0	FALSE	0
3510	47910	2011	1975	8	105,252.50	0	FALSE	0
3511	47910	1977	1976	3	-110,011.00	0	FALSE	0
3512	47910	1978	1976	0	-58.00	0	FALSE	0
3513	47910	1980	1976	0	-260.00	0	FALSE	0
3514	47910	1981	1976	0	-1,800.00	0	FALSE	0
3515	47910	1982	1976	0	-371.00	0	FALSE	0
3516	47910	1985	1976	0	-1,098.60	0	FALSE	0
3517	47910	1986	1976	0	-89.00	0	FALSE	0
3518	47910	1986	1976	4	1,476.00	1976	FALSE	0
3519	47910	1991	1976	0	-372.00	0	FALSE	0
3520	47910	1992	1976	0	-4,828.80	0	FALSE	0
3521	47910	1993	1976	0	-133.70	0	FALSE	0
3522	47910	1994	1976	0	-133.70	0	FALSE	0
3523	47910	2000	1976	0	-157.20	0	FALSE	0
3524	47910	2011	1976	0	-507.00	0	FALSE	0
3525	47910	2011	1976	8	70,666.88	0	FALSE	0
3526	47910	1978	1977	0	-509.00	0	FALSE	0
3527	47910	1979	1977	0	-627.00	0	FALSE	0
3528	47910	1981	1977	0	-1,184.00	0	FALSE	0
3529	47910	1982	1977	0	-747.00	0	FALSE	0
3530	47910	1984	1977	0	-711.00	0	FALSE	0
3531	47910	1986	1977	0	-530.80	0	FALSE	0
3532	47910	1986	1977	4	655.00	1977	FALSE	0
3533	47910	1987	1977	4	693.00	1977	FALSE	0
3534	47910	1988	1977	0	-198.00	0	FALSE	0
3535	47910	1989	1977	0	-483.00	0	FALSE	0
3536	47910	1991	1977	0	-388.50	0	FALSE	0
3537	47910	1992	1977	0	-4,287.20	0	FALSE	0
3538	47910	1993	1977	0	-6.50	0	FALSE	0
3539	47910	1994	1977	0	-164.80	0	FALSE	0
3540	47910	2002	1977	0	-527.80	0	FALSE	0
3541	47910	2010	1977	0	-77.00	0	FALSE	0
3542	47910	2011	1977	8	93,514.46	0	FALSE	0
3543	47910	1979	1978	0	-41.00	0	FALSE	0
3544	47910	1982	1978	0	-1,840.00	0	FALSE	0
3545	47910	1984	1978	0	-94.00	0	FALSE	0
3546	47910	1985	1978	0	-1,113.90	0	FALSE	0
3547	47910	1986	1978	0	-335.30	0	FALSE	0
3548	47910	1987	1978	0	-3,425.90	0	FALSE	0
3549	47910	1988	1978	0	-6,583.00	0	FALSE	0
3550	47910	1989	1978	0	-8,457.00	0	FALSE	0

3551	47910	1990	1978	0	-790.00	0	FALSE	0
3552	47910	1991	1978	0	-639.00	0	FALSE	0
3553	47910	1992	1978	0	-107.00	0	FALSE	0
3554	47910	1994	1978	0	-45.20	0	FALSE	0
3555	47910	1995	1978	0	-521.70	0	FALSE	0
3556	47910	2000	1978	0	-1,939.10	0	FALSE	0
3557	47910	2005	1978	0	-142.00	0	FALSE	0
3558	47910	2010	1978	0	-452.00	0	FALSE	0
3559	47910	2011	1978	8	141,818.02	0	FALSE	0
3560	47910	1981	1979	0	-616.00	0	FALSE	0
3561	47910	1982	1979	0	-429.00	0	FALSE	0
3562	47910	1983	1979	0	-650.00	0	FALSE	0
3563	47910	1984	1979	0	-64.00	0	FALSE	0
3564	47910	1986	1979	0	-1,216.30	0	FALSE	0
3565	47910	1987	1979	0	-124.20	0	FALSE	0
3566	47910	1988	1979	0	-158.00	0	FALSE	0
3567	47910	1989	1979	0	-3,325.00	0	FALSE	0
3568	47910	1990	1979	0	-3,771.80	0	FALSE	0
3569	47910	1991	1979	0	-343.00	0	FALSE	0
3570	47910	1992	1979	0	-2,954.20	0	FALSE	0
3571	47910	1994	1979	0	-508.20	0	FALSE	0
3572	47910	2001	1979	0	-612.80	0	FALSE	0
3573	47910	2005	1979	0	-178.90	0	FALSE	0
3574	47910	2006	1979	0	-145.00	0	FALSE	0
3575	47910	2008	1979	0	-482.90	0	FALSE	0
3576	47910	2011	1979	8	191,093.76	0	FALSE	0
3577	47910	1984	1980	0	-407.00	0	FALSE	0
3578	47910	1985	1980	0	-294.60	0	FALSE	0
3579	47910	1986	1980	0	-396.90	0	FALSE	0
3580	47910	1986	1980	4	2,282.00	1980	FALSE	0
3581	47910	1988	1980	0	-1,597.00	0	FALSE	0
3582	47910	1989	1980	0	0.00	0	FALSE	0
3583	47910	1991	1980	0	-883.00	0	FALSE	0
3584	47910	1992	1980	0	-879.20	0	FALSE	0
3585	47910	1994	1980	0	-131.20	0	FALSE	0
3586	47910	1995	1980	0	-155.20	0	FALSE	0
3587	47910	1996	1980	0	-1,037.20	0	FALSE	0
3588	47910	1997	1980	0	-10,303.20	0	FALSE	0
3589	47910	1998	1980	0	-2,282.70	0	FALSE	0
3590	47910	1999	1980	0	-13,335.90	0	FALSE	0
3591	47910	2000	1980	0	-77.60	0	FALSE	0
3592	47910	2001	1980	0	-2,023.80	0	FALSE	0
3593	47910	2002	1980	0	-232.80	0	FALSE	0
3594	47910	2003	1980	0	-77.60	0	FALSE	0
3595	47910	2005	1980	0	-1,902.00	0	FALSE	0
3596	47910	2007	1980	0	-655.00	0	FALSE	0
3597	47910	2008	1980	0	-553.90	0	FALSE	0
3598	47910	2009	1980	0	-88.80	0	FALSE	0
3599	47910	2011	1980	0	-6,819.00	0	FALSE	0
3600	47910	2011	1980	8	191,440.72	0	FALSE	0
3601	47910	1987	1981	0	-2,967.60	0	FALSE	0
3602	47910	1988	1981	0	-3,427.00	0	FALSE	0
3603	47910	1989	1981	0	0.00	0	FALSE	0

3604	47910	1990	1981	0	-469.90	0	FALSE	0
3605	47910	1991	1981	0	-843.10	0	FALSE	0
3606	47910	1992	1981	0	-449.10	0	FALSE	0
3607	47910	2000	1981	0	-1,674.20	0	FALSE	0
3608	47910	2009	1981	0	-99.00	0	FALSE	0
3609	47910	2011	1981	8	185,345.66	0	FALSE	0
3610	47910	1983	1982	0	-284.00	0	FALSE	0
3611	47910	1984	1982	0	-44,037.00	0	FALSE	0
3612	47910	1987	1982	0	-1,071.00	0	FALSE	0
3613	47910	1988	1982	0	-84.00	0	FALSE	0
3614	47910	1989	1982	0	-179.00	0	FALSE	0
3615	47910	1990	1982	0	-2,250.90	0	FALSE	0
3616	47910	1998	1982	0	-2,826.80	0	FALSE	0
3617	47910	2002	1982	0	-901.80	0	FALSE	0
3618	47910	2003	1982	0	-360.20	0	FALSE	0
3619	47910	2011	1982	8	125,172.27	0	FALSE	0
3620	47910	1985	1983	4	3,060.00	1983	FALSE	0
3621	47910	1986	1983	0	-621.80	0	FALSE	0
3622	47910	1986	1983	4	4,876.00	1983	FALSE	0
3623	47910	1987	1983	0	-961.60	0	FALSE	0
3624	47910	1988	1983	0	-2,291.00	0	FALSE	0
3625	47910	1989	1983	0	0.00	0	FALSE	0
3626	47910	1990	1983	0	-3,395.40	0	FALSE	0
3627	47910	1991	1983	0	-4,377.90	0	FALSE	0
3628	47910	1992	1983	0	-947.50	0	FALSE	0
3629	47910	2011	1983	8	65,923.13	0	FALSE	0
3630	47910	1987	1984	0	-211.60	0	FALSE	0
3631	47910	1988	1984	0	-5,445.00	0	FALSE	0
3632	47910	1989	1984	0	-2,139.00	0	FALSE	0
3633	47910	1990	1984	0	-3,047.00	0	FALSE	0
3634	47910	1991	1984	0	-9,477.30	0	FALSE	0
3635	47910	1994	1984	0	-469.20	0	FALSE	0
3636	47910	1995	1984	0	-2,052.50	0	FALSE	0
3637	47910	2002	1984	0	-104.80	0	FALSE	0
3638	47910	2011	1984	8	57,612.00	0	FALSE	0
3639	47910	1986	1985	0	-3,376.00	0	FALSE	0
3640	47910	1986	1985	4	2,758.00	1985	FALSE	0
3641	47910	1987	1985	0	-1,363.40	0	FALSE	0
3642	47910	1987	1985	4	2,188.00	1985	FALSE	0
3643	47910	1988	1985	0	-2,910.00	0	FALSE	0
3644	47910	1989	1985	0	-1,911.00	0	FALSE	0
3645	47910	1990	1985	0	-1,499.70	0	FALSE	0
3646	47910	1994	1985	0	-647.20	0	FALSE	0
3647	47910	1997	1985	0	-1,184.00	0	FALSE	0
3648	47910	1998	1985	0	-3,010.50	0	FALSE	0
3649	47910	2003	1985	0	-920.80	0	FALSE	0
3650	47910	2003	1985	0	-1,579.20	0	FALSE	0
3651	47910	2005	1985	0	-509.00	0	FALSE	0
3652	47910	2006	1985	0	-299.00	0	FALSE	0
3653	47910	2007	1985	0	-198.00	0	FALSE	0
3654	47910	2010	1985	0	-223.00	0	FALSE	0
3655	47910	2011	1985	8	202,526.99	0	FALSE	0
3656	47910	1986	1986	0	-3,695.00	0	FALSE	0

3657	47910	1987	1986	0	-13.30	0	FALSE	0
3658	47910	1987	1986	4	2,267.00	1986	FALSE	0
3659	47910	1988	1986	0	-149.00	0	FALSE	0
3660	47910	1989	1986	0	-817.00	0	FALSE	0
3661	47910	1995	1986	0	-3,752.90	0	FALSE	0
3662	47910	1998	1986	0	-2,738.10	0	FALSE	0
3663	47910	2004	1986	0	-946.00	0	FALSE	0
3664	47910	2005	1986	0	-103.90	0	FALSE	0
3665	47910	2009	1986	0	-104.00	0	FALSE	0
3666	47910	2011	1986	8	205,124.37	0	FALSE	0
3667	47910	1988	1987	0	-637.00	0	FALSE	0
3668	47910	1988	1987	4	26,711.00	1987	FALSE	0
3669	47910	1989	1987	0	-2,267.00	0	FALSE	0
3670	47910	1990	1987	0	-94.60	0	FALSE	0
3671	47910	2002	1987	0	-94.30	0	FALSE	0
3672	47910	2003	1987	0	-1,381.60	0	FALSE	0
3673	47910	2003	1987	0	-198.40	0	FALSE	0
3674	47910	2007	1987	0	-212.00	0	FALSE	0
3675	47910	2010	1987	0	-372.00	0	FALSE	0
3676	47910	2011	1987	8	505,597.46	0	FALSE	0
3677	47910	1989	1988	0	-2,022.00	0	FALSE	0
3678	47910	1990	1988	0	-1,032.90	0	FALSE	0
3679	47910	1990	1988	4	15,160.00	1988	FALSE	0
3680	47910	1991	1988	0	-7,314.70	0	FALSE	0
3681	47910	1995	1988	0	-323.00	0	FALSE	0
3682	47910	1997	1988	0	-96.60	0	FALSE	0
3683	47910	1999	1988	0	-1,038.60	0	FALSE	0
3684	47910	2000	1988	0	-98.90	0	FALSE	0
3685	47910	2001	1988	0	-98.90	0	FALSE	0
3686	47910	2011	1988	8	306,132.88	0	FALSE	0
3687	47910	1989	1989	0	0.00	0	FALSE	0
3688	47910	1990	1989	0	-799.00	0	FALSE	0
3689	47910	1990	1989	4	83,444.38	1989	FALSE	0
3690	47910	1995	1989	4	3,809.00	1989	FALSE	0
3691	47910	1997	1989	0	-101.00	0	FALSE	0
3692	47910	2011	1989	8	485,270.58	0	FALSE	0
3693	47910	1991	1990	0	-13,452.00	0	FALSE	0
3694	47910	1991	1990	4	84,828.00	1990	FALSE	0
3695	47910	1995	1990	4	10,023.00	1990	FALSE	0
3696	47910	1996	1990	0	-1,854.80	0	FALSE	0
3697	47910	1997	1990	0	-108.20	0	FALSE	0
3698	47910	1998	1990	0	-108.20	0	FALSE	0
3699	47910	1999	1990	0	-6,779.20	0	FALSE	0
3700	47910	2002	1990	0	-108.20	0	FALSE	0
3701	47910	2005	1990	0	-110.90	0	FALSE	0
3702	47910	2008	1990	0	-177.00	0	FALSE	0
3703	47910	2011	1990	8	725,712.71	0	FALSE	0
3704	47910	1991	1991	0	-12,255.00	0	FALSE	0
3705	47910	1992	1991	4	9,396.00	1991	FALSE	0
3706	47910	1995	1991	0	-1,628.00	0	FALSE	0
3707	47910	1995	1991	4	20,691.00	1991	FALSE	0
3708	47910	1998	1991	0	-1,243.90	0	FALSE	0
3709	47910	2009	1991	0	-177.00	0	FALSE	0

3710	47910	2011	1991	8	767,112.63	0	FALSE	0
3711	47910	1993	1992	4	3,615.34	1992	FALSE	0
3712	47910	1995	1992	4	13,892.00	1992	FALSE	0
3713	47910	2006	1992	0	-604.90	0	FALSE	0
3714	47910	2011	1992	8	770,960.71	0	FALSE	0
3715	47910	1995	1993	4	34,635.00	1993	FALSE	0
3716	47910	2011	1993	8	941,284.95	0	FALSE	0
3717	47910	1994	1994	3	-19,832.70	1994	FALSE	0
3718	47910	1995	1994	0	-354.10	0	FALSE	0
3719	47910	1995	1994	4	8,544.00	1994	FALSE	0
3720	47910	2002	1994	0	-123.50	0	FALSE	0
3721	47910	2011	1994	8	504,127.56	0	FALSE	0
3722	47910	1996	1995	0	-1,322.00	0	FALSE	0
3723	47910	2003	1995	0	-245.30	0	FALSE	0
3724	47910	2005	1995	0	-136.00	0	FALSE	0
3725	47910	2006	1995	0	-136.00	0	FALSE	0
3726	47910	2009	1995	0	-718.00	0	FALSE	0
3727	47910	2011	1995	8	470,411.85	0	FALSE	0
3728	47910	1997	1996	4	49,430.98	1996	FALSE	0
3729	47910	1998	1996	0	-118.30	0	FALSE	0
3730	47910	1999	1996	0	-1,338.60	0	FALSE	0
3731	47910	2008	1996	0	-295.00	0	FALSE	0
3732	47910	2011	1996	8	655,953.00	0	FALSE	0
3733	47910	1997	1997	4	2,529.52	1997	FALSE	0
3734	47910	2000	1997	0	-245.30	0	FALSE	0
3735	47910	2003	1997	0	-116.80	0	FALSE	0
3736	47910	2011	1997	0	-9,232.10	0	FALSE	0
3737	47910	2011	1997	8	483,875.09	0	FALSE	0
3738	47910	2007	1998	0	-935.00	0	FALSE	0
3739	47910	2011	1998	8	494,985.10	0	FALSE	0
3740	47910	2001	1999	0	-1,017.50	0	FALSE	0
3741	47910	2006	1999	0	-277.00	0	FALSE	0
3742	47910	2010	1999	0	-2,448.90	0	FALSE	0
3743	47910	2011	1999	8	375,346.25	0	FALSE	0
3744	47910	2001	2000	0	-1,392.10	0	FALSE	0
3745	47910	2001	2000	3	-19,820.60	2000	FALSE	0
3746	47910	2002	2000	0	-1,770.30	0	FALSE	0
3747	47910	2006	2000	0	-16,274.00	0	FALSE	0
3748	47910	2011	2000	8	591,914.63	0	FALSE	0
3749	47910	2007	2001	0	-480.00	0	FALSE	0
3750	47910	2011	2001	8	574,603.49	0	FALSE	0
3751	47910	2004	2002	0	-1,481.40	0	FALSE	0
3752	47910	2011	2002	8	539,849.29	0	FALSE	0
3753	47910	2011	2003	8	740,255.14	0	FALSE	0
3754	47910	2008	2004	0	-151.00	0	FALSE	0
3755	47910	2008	2004	4	13,173.79	2004	FALSE	0
3756	47910	2009	2004	0	-855.00	0	FALSE	0
3757	47910	2009	2004	3	-80,341.20	0	FALSE	0
3758	47910	2010	2004	4	8,466.92	0	FALSE	0
3759	47910	2011	2004	3	-6,045.60	2004	FALSE	0
3760	47910	2011	2004	8	737,246.07	0	FALSE	0
3761	47910	2008	2005	3	-1,411.50	2005	FALSE	0
3762	47910	2011	2005	8	1,390,573.02	0	FALSE	0

3763	47910	2008	2006	3	-1,203.00	2006	FALSE	0
3764	47910	2009	2006	4	25,274.17	0	FALSE	0
3765	47910	2011	2006	8	1,480,794.08	0	FALSE	0
3766	47910	2008	2007	4	82,777.46	2007	FALSE	0
3767	47910	2009	2007	4	12,747.57	0	FALSE	0
3768	47910	2010	2007	3	-4,609.90	0	FALSE	0
3769	47910	2011	2007	3	-15.80	2007	FALSE	0
3770	47910	2011	2007	8	1,586,755.13	0	FALSE	0
3771	47910	2009	2008	4	132,424.01	0	FALSE	0
3772	47910	2010	2008	0	-10,751.90	0	FALSE	0
3773	47910	2010	2008	3	-1,376.00	0	FALSE	0
3774	47910	2011	2008	8	1,953,714.12	0	FALSE	0
3775	47910	2010	2009	0	-6,924.00	0	FALSE	0
3776	47910	2010	2009	4	1,421.03	0	FALSE	0
3777	47910	2011	2009	4	519.81	2009	FALSE	0
3778	47910	2011	2009	8	1,715,673.49	0	FALSE	0
3779	47910	2011	2010	4	55,016.54	2010	FALSE	0
3780	47910	2011	2010	8	1,410,673.11	0	FALSE	0
3781	47910	2011	2011	8	1,741,434.38	0	FALSE	0
3782	48200	1978	1957	0	-24,780.00	0	FALSE	0
3783	48200	1978	1959	0	-2,788.00	0	FALSE	0
3784	48200	1985	1959	4	30,938.75	1959	FALSE	0
3785	48200	1992	1959	0	-30,939.50	0	FALSE	0
3786	48200	1978	1960	0	-3,684.00	0	FALSE	0
3787	48200	1978	1961	0	-1,586.00	0	FALSE	0
3788	48200	1992	1962	0	-230.00	0	FALSE	0
3789	48200	1978	1964	0	-1,089.00	0	FALSE	0
3790	48200	1992	1965	0	-4,613.00	0	FALSE	0
3791	48200	1978	1968	0	-258.00	0	FALSE	0
3792	48200	1988	1968	0	-1,522.00	0	FALSE	0
3793	48200	1992	1968	0	-140,247.00	0	FALSE	0
3794	48200	1978	1969	0	-3,305.00	0	FALSE	0
3795	48200	1992	1969	0	-5,188.00	0	FALSE	0
3796	48200	1992	1970	0	-13,273.00	0	FALSE	0
3797	48200	1992	1971	0	-6,942.00	0	FALSE	0
3798	48200	1992	1972	0	-496.50	0	FALSE	0
3799	48200	2011	1972	8	59,482.48	0	FALSE	0
3800	48200	2011	1973	8	16,635.00	0	FALSE	0
3801	48200	2011	1974	8	46,735.00	0	FALSE	0
3802	48200	2011	1976	8	1,500.00	0	FALSE	0
3803	48200	1995	1977	0	-553.00	0	FALSE	0
3804	48200	2011	1977	8	1,015.00	0	FALSE	0
3805	48200	2011	1979	8	14,807.00	0	FALSE	0
3806	48200	2011	1981	8	12,462.00	0	FALSE	0
3807	48200	1983	1982	3	-5,448.00	1982	FALSE	0
3808	48200	2011	1982	8	21,706.00	0	FALSE	0
3809	48200	2011	1984	8	24,285.00	0	FALSE	0
3810	48200	2011	1986	8	2,778.08	0	FALSE	0
3811	48200	2011	1987	8	379,195.74	0	FALSE	0
3812	48200	2011	1988	8	87,857.59	0	FALSE	0
3813	48200	2011	1989	8	3,500.00	0	FALSE	0
3814	48200	1991	1990	4	42,653.00	1990	FALSE	0
3815	48200	2011	1990	8	45,253.00	0	FALSE	0

3816	48200	1992	1991	3	-239,000.00	1991	FALSE	0
3817	48200	2011	1991	8	1,424,433.43	0	FALSE	0
3818	48200	2011	1992	8	300,985.15	0	FALSE	0
3819	48200	1994	1993	4	25,205.58	1993	FALSE	0
3820	48200	1997	1993	3	-12,722.00	1993	FALSE	0
3821	48200	2011	1993	8	117,588.04	0	FALSE	0
3822	48200	1997	1994	4	12,483.63	1994	FALSE	0
3823	48200	2011	1994	8	58,849.20	0	FALSE	0
3824	48200	1997	1995	3	-16,593.20	1995	FALSE	0
3825	48200	1997	1995	4	25,205.58	1995	FALSE	0
3826	48200	2011	1995	8	33,602.05	0	FALSE	0
3827	48200	1997	1996	4	20,279.58	1996	FALSE	0
3828	48200	2011	1996	8	25,776.27	0	FALSE	0
3829	48200	1998	1997	3	-7,975.70	1997	FALSE	0
3830	48200	2011	1997	8	55,730.18	0	FALSE	0
3831	48200	1999	1998	3	-3,500.00	1998	FALSE	0
3832	48200	1999	1998	3	-12,405.90	1998	FALSE	0
3833	48200	2011	1998	8	83,574.87	0	FALSE	0
3834	48200	2011	1999	8	9,019.44	0	FALSE	0
3835	48200	2011	2000	8	50,931.86	0	FALSE	0
3836	48200	2001	2001	4	40,194.78	2001	FALSE	0
3837	48200	2011	2001	8	47,503.75	0	FALSE	0
3838	48200	2011	2002	8	25,441.90	0	FALSE	0
3839	48200	2011	2003	8	46,885.37	0	FALSE	0
3840	48200	2011	2004	8	48,669.62	0	FALSE	0
3841	48200	2011	2005	8	3,289.66	0	FALSE	0
3842	48200	2011	2006	8	83,642.46	0	FALSE	0
3843	48200	2011	2007	8	12,536.74	0	FALSE	0
3844	48200	2011	2008	8	76,031.98	0	FALSE	0
3845	48200	2011	2009	8	74,558.63	0	FALSE	0
3846	48200	2011	2010	8	98,128.40	0	FALSE	0
3847	48200	2011	2011	8	64,924.42	0	FALSE	0
3848	48300	1960	1945	0	-288.00	0	FALSE	0
3849	48300	1982	1945	0	-310.00	0	FALSE	0
3850	48300	1960	1946	0	-43.00	0	FALSE	0
3851	48300	1982	1946	0	-47.00	0	FALSE	0
3852	48300	1960	1947	0	-50.00	0	FALSE	0
3853	48300	1982	1947	0	-53.00	0	FALSE	0
3854	48300	1960	1948	0	-57.00	0	FALSE	0
3855	48300	1982	1948	0	-62.00	0	FALSE	0
3856	48300	1960	1949	0	-65.00	0	FALSE	0
3857	48300	1982	1949	0	-71.00	0	FALSE	0
3858	48300	1960	1950	0	-76.00	0	FALSE	0
3859	48300	1982	1950	0	-81.00	0	FALSE	0
3860	48300	1960	1951	0	-87.00	0	FALSE	0
3861	48300	1982	1951	0	-94.00	0	FALSE	0
3862	48300	1960	1952	0	-133.00	0	FALSE	0
3863	48300	1982	1952	0	-144.00	0	FALSE	0
3864	48300	1960	1953	0	-239.00	0	FALSE	0
3865	48300	1982	1953	0	-246.00	0	FALSE	0
3866	48300	1983	1953	0	-13.00	0	FALSE	0
3867	48300	1960	1954	0	-312.00	0	FALSE	0
3868	48300	1982	1954	0	-302.00	0	FALSE	0

3869	48300	1983	1954	0	-32.00	0	FALSE	0
3870	48300	1984	1954	0	-2.00	0	FALSE	0
3871	48300	1960	1955	0	-270.00	0	FALSE	0
3872	48300	1982	1955	0	-247.00	0	FALSE	0
3873	48300	1983	1955	0	-40.00	0	FALSE	0
3874	48300	1984	1955	0	-4.00	0	FALSE	0
3875	48300	1960	1956	0	-324.00	0	FALSE	0
3876	48300	1982	1956	0	-279.00	0	FALSE	0
3877	48300	1983	1956	0	-60.00	0	FALSE	0
3878	48300	1984	1956	0	-9.00	0	FALSE	0
3879	48300	1985	1956	0	-1.00	0	FALSE	0
3880	48300	1960	1957	0	-389.00	0	FALSE	0
3881	48300	1982	1957	0	-314.00	0	FALSE	0
3882	48300	1983	1957	0	-84.00	0	FALSE	0
3883	48300	1984	1957	0	-18.00	0	FALSE	0
3884	48300	1985	1957	0	-3.00	0	FALSE	0
3885	48300	1959	1958	0	-119.00	0	FALSE	0
3886	48300	1982	1958	0	-690.00	0	FALSE	0
3887	48300	1983	1958	0	-221.00	0	FALSE	0
3888	48300	1984	1958	0	-59.00	0	FALSE	0
3889	48300	1985	1958	0	-13.00	0	FALSE	0
3890	48300	1986	1958	0	-2.00	0	FALSE	0
3891	48300	1987	1958	4	662.50	1958	FALSE	0
3892	48300	1988	1958	0	-662.50	0	FALSE	0
3893	48300	1967	1960	0	-359.00	0	FALSE	0
3894	48300	1971	1960	0	-270.00	0	FALSE	0
3895	48300	1982	1960	0	-883.00	0	FALSE	0
3896	48300	1983	1960	0	-383.00	0	FALSE	0
3897	48300	1984	1960	0	-144.00	0	FALSE	0
3898	48300	1985	1960	0	-41.00	0	FALSE	0
3899	48300	1986	1960	0	-21.00	0	FALSE	0
3900	48300	1982	1961	0	-423.00	0	FALSE	0
3901	48300	1983	1961	0	-208.00	0	FALSE	0
3902	48300	1984	1961	0	-90.00	0	FALSE	0
3903	48300	1985	1961	0	-48.00	0	FALSE	0
3904	48300	1982	1962	0	-418.00	0	FALSE	0
3905	48300	1983	1962	0	-230.00	0	FALSE	0
3906	48300	1984	1962	0	-113.00	0	FALSE	0
3907	48300	1985	1962	0	-6.00	0	FALSE	0
3908	48300	1986	1962	0	-69.00	0	FALSE	0
3909	48300	1982	1963	0	-32.00	0	FALSE	0
3910	48300	1983	1963	0	-20.00	0	FALSE	0
3911	48300	1984	1963	0	-11.00	0	FALSE	0
3912	48300	1985	1963	0	-70.00	0	FALSE	0
3913	48300	1982	1964	0	-281.00	0	FALSE	0
3914	48300	1983	1964	0	-189.00	0	FALSE	0
3915	48300	1984	1964	0	-116.00	0	FALSE	0
3916	48300	1985	1964	0	-50.00	0	FALSE	0
3917	48300	1986	1964	0	-5.00	0	FALSE	0
3918	48300	1982	1965	0	-367.00	0	FALSE	0
3919	48300	1983	1965	0	-272.00	0	FALSE	0
3920	48300	1984	1965	0	-184.00	0	FALSE	0
3921	48300	1985	1965	0	-124.00	0	FALSE	0

3922	48300	1986	1965	0	-61.00	0	FALSE	0
3923	48300	1987	1965	0	-26.00	0	FALSE	0
3924	48300	1987	1965	4	84.52	1965	FALSE	0
3925	48300	1988	1965	0	-69.00	0	FALSE	0
3926	48300	1989	1965	0	-22.00	0	FALSE	0
3927	48300	1990	1965	0	-7.40	0	FALSE	0
3928	48300	1982	1966	0	-488.00	0	FALSE	0
3929	48300	1983	1966	0	-398.00	0	FALSE	0
3930	48300	1984	1966	0	-296.00	0	FALSE	0
3931	48300	1985	1966	0	-222.00	0	FALSE	0
3932	48300	1986	1966	0	-122.00	0	FALSE	0
3933	48300	1987	1966	0	-60.00	0	FALSE	0
3934	48300	1988	1966	0	-26.00	0	FALSE	0
3935	48300	1989	1966	0	-10.00	0	FALSE	0
3936	48300	1990	1966	0	-4.20	0	FALSE	0
3937	48300	1982	1967	0	-500.00	0	FALSE	0
3938	48300	1983	1967	0	-451.00	0	FALSE	0
3939	48300	1984	1967	0	-368.00	0	FALSE	0
3940	48300	1985	1967	0	-307.00	0	FALSE	0
3941	48300	1986	1967	0	-188.00	0	FALSE	0
3942	48300	1987	1967	0	-103.00	0	FALSE	0
3943	48300	1988	1967	0	-50.80	0	FALSE	0
3944	48300	1989	1967	0	-22.00	0	FALSE	0
3945	48300	1990	1967	0	-8.30	0	FALSE	0
3946	48300	1991	1967	0	-3.60	0	FALSE	0
3947	48300	1982	1968	0	-569.00	0	FALSE	0
3948	48300	1983	1968	0	-569.00	0	FALSE	0
3949	48300	1984	1968	0	-512.00	0	FALSE	0
3950	48300	1985	1968	0	-478.00	0	FALSE	0
3951	48300	1986	1968	0	-322.00	0	FALSE	0
3952	48300	1987	1968	0	-197.00	0	FALSE	0
3953	48300	1988	1968	0	-108.40	0	FALSE	0
3954	48300	1989	1968	0	-53.00	0	FALSE	0
3955	48300	1990	1968	0	-23.10	0	FALSE	0
3956	48300	1991	1968	0	-8.70	0	FALSE	0
3957	48300	1992	1968	0	-3.70	0	FALSE	0
3958	48300	1977	1969	0	-100.00	0	FALSE	0
3959	48300	1982	1969	0	-398.00	0	FALSE	0
3960	48300	1983	1969	0	-450.00	0	FALSE	0
3961	48300	1984	1969	0	-450.00	0	FALSE	0
3962	48300	1985	1969	0	-473.00	0	FALSE	0
3963	48300	1986	1969	0	-352.00	0	FALSE	0
3964	48300	1987	1969	0	-237.00	0	FALSE	0
3965	48300	1988	1969	0	-144.40	0	FALSE	0
3966	48300	1989	1969	0	-80.00	0	FALSE	0
3967	48300	1990	1969	0	-39.30	0	FALSE	0
3968	48300	1991	1969	0	-17.00	0	FALSE	0
3969	48300	1992	1969	0	-9.20	0	FALSE	0
3970	48300	1982	1970	0	-35.00	0	FALSE	0
3971	48300	1983	1970	0	-47.00	0	FALSE	0
3972	48300	1984	1970	0	-53.00	0	FALSE	0
3973	48300	1985	1970	0	-64.00	0	FALSE	0
3974	48300	1986	1970	0	-52.00	0	FALSE	0

3975	48300	1987	1970	0	-39.00	0	FALSE	0
3976	48300	1988	1970	0	-26.50	0	FALSE	0
3977	48300	1989	1970	0	-16.00	0	FALSE	0
3978	48300	1990	1970	0	-8.90	0	FALSE	0
3979	48300	1991	1970	0	-7.30	0	FALSE	0
3980	48300	1982	1971	0	-163.00	0	FALSE	0
3981	48300	1983	1971	0	-310.00	0	FALSE	0
3982	48300	1984	1971	0	-419.00	0	FALSE	0
3983	48300	1985	1971	0	-594.00	0	FALSE	0
3984	48300	1986	1971	0	-535.00	0	FALSE	0
3985	48300	1987	1971	0	-436.00	0	FALSE	0
3986	48300	1988	1971	0	-324.20	0	FALSE	0
3987	48300	1989	1971	0	-219.00	0	FALSE	0
3988	48300	1990	1971	0	-133.70	0	FALSE	0
3989	48300	1991	1971	0	-73.60	0	FALSE	0
3990	48300	1992	1971	0	-60.20	0	FALSE	0
3991	48300	1976	1972	0	-351.00	0	FALSE	0
3992	48300	1983	1972	0	-75.00	0	FALSE	0
3993	48300	1984	1972	0	-143.00	0	FALSE	0
3994	48300	1985	1972	0	-257.00	0	FALSE	0
3995	48300	1986	1972	0	-257.00	0	FALSE	0
3996	48300	1987	1972	0	-232.00	0	FALSE	0
3997	48300	1988	1972	0	-189.10	0	FALSE	0
3998	48300	1989	1972	0	-141.00	0	FALSE	0
3999	48300	1990	1972	0	-94.80	0	FALSE	0
4000	48300	1991	1972	0	-58.00	0	FALSE	0
4001	48300	1992	1972	0	-58.00	0	FALSE	0
4002	48300	1984	1973	0	-100.00	0	FALSE	0
4003	48300	1985	1973	0	-286.00	0	FALSE	0
4004	48300	1986	1973	0	-324.00	0	FALSE	0
4005	48300	1987	1973	0	-324.00	0	FALSE	0
4006	48300	1988	1973	0	-291.60	0	FALSE	0
4007	48300	1989	1973	0	-238.00	0	FALSE	0
4008	48300	1990	1973	0	-176.90	0	FALSE	0
4009	48300	1991	1973	0	-119.40	0	FALSE	0
4010	48300	1992	1973	0	-146.00	0	FALSE	0
4011	48300	1985	1974	0	-226.00	0	FALSE	0
4012	48300	1986	1974	0	-306.00	0	FALSE	0
4013	48300	1987	1974	0	-346.00	0	FALSE	0
4014	48300	1988	1974	0	-346.40	0	FALSE	0
4015	48300	1989	1974	0	-312.00	0	FALSE	0
4016	48300	1990	1974	0	-254.60	0	FALSE	0
4017	48300	1991	1974	0	-189.10	0	FALSE	0
4018	48300	1992	1974	0	-283.70	0	FALSE	0
4019	48300	1989	1975	0	0.00	0	FALSE	0
4020	48300	1986	1976	0	-651.00	0	FALSE	0
4021	48300	1987	1976	0	-57.00	0	FALSE	0
4022	48300	1988	1976	0	-76.80	0	FALSE	0
4023	48300	1989	1976	0	-87.00	0	FALSE	0
4024	48300	1990	1976	0	-87.10	0	FALSE	0
4025	48300	1991	1976	0	-78.40	0	FALSE	0
4026	48300	1992	1976	0	-182.80	0	FALSE	0
4027	48300	1987	1977	0	-147.00	0	FALSE	0

4028	48300	1988	1977	0	-279.80	0	FALSE	0
4029	48300	1989	1977	0	-378.00	0	FALSE	0
4030	48300	1990	1977	0	-428.10	0	FALSE	0
4031	48300	1991	1977	0	-428.10	0	FALSE	0
4032	48300	1992	1977	0	-1,214.00	0	FALSE	0
4033	48300	1993	1977	0	-70.10	0	FALSE	0
4034	48300	1988	1978	0	-180.10	0	FALSE	0
4035	48300	1989	1978	0	-342.00	0	FALSE	0
4036	48300	1990	1978	0	-461.80	0	FALSE	0
4037	48300	1991	1978	0	-523.40	0	FALSE	0
4038	48300	1993	1978	0	-523.40	0	FALSE	0
4039	48300	1994	1978	0	-471.10	0	FALSE	0
4040	48300	1995	1978	0	-1,099.10	0	FALSE	0
4041	48300	1989	1979	0	-254.00	0	FALSE	0
4042	48300	1990	1979	0	-482.60	0	FALSE	0
4043	48300	1991	1979	0	-651.50	0	FALSE	0
4044	48300	1993	1979	0	-738.40	0	FALSE	0
4045	48300	1994	1979	0	-738.40	0	FALSE	0
4046	48300	1995	1979	0	-712.30	0	FALSE	0
4047	48300	1996	1979	0	-596.00	0	FALSE	0
4048	48300	1997	1979	0	-426.00	0	FALSE	0
4049	48300	1998	1979	0	-480.80	0	FALSE	0
4050	48300	1990	1980	0	-171.00	0	FALSE	0
4051	48300	1991	1980	0	-324.90	0	FALSE	0
4052	48300	1993	1980	0	-438.60	0	FALSE	0
4053	48300	1994	1980	0	-497.10	0	FALSE	0
4054	48300	1995	1980	0	-239.50	0	FALSE	0
4055	48300	1996	1980	0	-570.00	0	FALSE	0
4056	48300	1997	1980	0	-467.00	0	FALSE	0
4057	48300	1998	1980	0	-382.10	0	FALSE	0
4058	48300	1999	1980	0	-329.80	0	FALSE	0
4059	48300	1991	1981	0	-65.90	0	FALSE	0
4060	48300	1993	1981	0	-125.20	0	FALSE	0
4061	48300	1994	1981	0	-169.00	0	FALSE	0
4062	48300	1995	1981	0	-811.70	0	FALSE	0
4063	48300	1996	1981	0	-38.00	0	FALSE	0
4064	48300	1997	1981	0	-35.00	0	FALSE	0
4065	48300	1998	1981	0	-73.10	0	FALSE	0
4066	48300	1993	1982	0	-237.40	0	FALSE	0
4067	48300	1994	1982	0	-451.00	0	FALSE	0
4068	48300	1995	1982	0	-1,445.40	0	FALSE	0
4069	48300	1996	1982	0	-509.00	0	FALSE	0
4070	48300	1997	1982	0	-543.00	0	FALSE	0
4071	48300	1998	1982	0	-402.60	0	FALSE	0
4072	48300	1999	1982	0	-459.10	0	FALSE	0
4073	48300	2000	1982	0	-277.20	0	FALSE	0
4074	48300	2001	1982	0	-230.00	0	FALSE	0
4075	48300	2002	1982	0	-192.20	0	FALSE	0
4076	48300	1994	1983	0	-507.20	0	FALSE	0
4077	48300	1995	1983	0	-378.70	0	FALSE	0
4078	48300	1996	1983	0	-1,275.00	0	FALSE	0
4079	48300	1997	1983	0	-1,554.00	0	FALSE	0
4080	48300	1998	1983	0	-1,251.50	0	FALSE	0

4081	48300	1999	1983	0	-1,686.30	0	FALSE	0
4082	48300	2000	1983	0	-1,137.00	0	FALSE	0
4083	48300	2001	1983	0	-1,104.70	0	FALSE	0
4084	48300	2002	1983	0	-680.10	0	FALSE	0
4085	48300	1995	1984	0	-1,740.10	0	FALSE	0
4086	48300	1996	1984	0	-184.00	0	FALSE	0
4087	48300	1997	1984	0	-257.00	0	FALSE	0
4088	48300	1998	1984	0	-221.10	0	FALSE	0
4089	48300	1999	1984	0	-357.00	0	FALSE	0
4090	48300	2000	1984	0	-265.00	0	FALSE	0
4091	48300	2001	1984	0	-302.20	0	FALSE	0
4092	48300	2002	1984	0	-460.40	0	FALSE	0
4093	48300	1996	1985	0	-1,820.00	0	FALSE	0
4094	48300	1997	1985	0	-2,957.00	0	FALSE	0
4095	48300	1998	1985	0	-2,691.80	0	FALSE	0
4096	48300	1999	1985	0	-5,321.70	0	FALSE	0
4097	48300	2000	1985	0	-4,285.60	0	FALSE	0
4098	48300	2001	1985	0	-5,774.70	0	FALSE	0
4099	48300	2002	1985	0	-4,736.50	0	FALSE	0
4100	48300	2005	1985	0	-1,330.20	0	FALSE	0
4101	48300	2006	1985	0	-1,520.30	0	FALSE	0
4102	48300	2007	1985	0	-977.60	0	FALSE	0
4103	48300	2011	1985	8	0.00	0	FALSE	0
4104	48300	1996	1986	0	-343.00	0	FALSE	0
4105	48300	1997	1986	0	-664.00	0	FALSE	0
4106	48300	1998	1986	0	-629.00	0	FALSE	0
4107	48300	1999	1986	0	-1,569.20	0	FALSE	0
4108	48300	2000	1986	0	-1,353.10	0	FALSE	0
4109	48300	2001	1986	0	-2,185.00	0	FALSE	0
4110	48300	2002	1986	0	-2,048.50	0	FALSE	0
4111	48300	2005	1986	0	-782.30	0	FALSE	0
4112	48300	2008	1986	0	-1,777.30	0	FALSE	0
4113	48300	2011	1986	8	0.00	0	FALSE	0
4114	48300	1992	1987	0	-3,500.00	0	FALSE	0
4115	48300	1996	1987	0	-314.00	0	FALSE	0
4116	48300	1997	1987	0	-734.00	0	FALSE	0
4117	48300	1998	1987	0	-714.30	0	FALSE	0
4118	48300	1999	1987	0	-2,365.40	0	FALSE	0
4119	48300	2000	1987	0	-2,153.30	0	FALSE	0
4120	48300	2001	1987	0	-4,257.20	0	FALSE	0
4121	48300	2002	1987	0	-4,540.90	0	FALSE	0
4122	48300	2005	1987	0	-2,320.80	0	FALSE	0
4123	48300	2006	1987	0	-1,892.20	0	FALSE	0
4124	48300	2008	1987	0	-4,598.10	0	FALSE	0
4125	48300	2011	1987	8	0.00	0	FALSE	0
4126	48300	1990	1988	4	3,500.00	1988	FALSE	0
4127	48300	1996	1988	0	-149.00	0	FALSE	0
4128	48300	1997	1988	0	-444.00	0	FALSE	0
4129	48300	1998	1988	0	-11,938.90	0	FALSE	0
4130	48300	1999	1988	0	-1,432.90	0	FALSE	0
4131	48300	2000	1988	0	-1,358.00	0	FALSE	0
4132	48300	2001	1988	0	-3,387.70	0	FALSE	0
4133	48300	2002	1988	0	-4,130.30	0	FALSE	0

4134	48300	2005	1988	0	-2,819.10	0		FALSE	0
4135	48300	2006	1988	0	-2,477.20	0		FALSE	0
4136	48300	2007	1988	0	-2,100.30	0		FALSE	0
4137	48300	2009	1988	0	-2,506.40	0		FALSE	0
4138	48300	2010	1988	0	-130.80	0		FALSE	0
4139	48300	2011	1988	0	-632.00	0		FALSE	0
4140	48300	2011	1988	8	834.92	0		FALSE	0
4141	48300	1996	1989	0	-49.00	0		FALSE	0
4142	48300	1997	1989	0	-198.00	0		FALSE	0
4143	48300	1998	1989	0	-196.90	0		FALSE	0
4144	48300	1999	1989	0	-1,382.50	0		FALSE	0
4145	48300	2000	1989	0	-1,346.00	0		FALSE	0
4146	48300	2001	1989	0	-4,457.30	0		FALSE	0
4147	48300	2002	1989	0	-6,232.50	0		FALSE	0
4148	48300	2005	1989	0	-5,744.60	0		FALSE	0
4149	48300	2006	1989	0	-5,447.80	0		FALSE	0
4150	48300	2007	1989	0	-4,961.90	0		FALSE	0
4151	48300	2008	1989	0	-1,670.80	0		FALSE	0
4152	48300	2009	1989	0	-6,455.70	0		FALSE	0
4153	48300	2010	1989	0	-3,371.10	0		FALSE	0
4154	48300	2011	1989	0	-1,627.90	0		FALSE	0
4155	48300	2011	1989	8	2,150.48	0		FALSE	0
4156	48300	1991	1990	3	-42,653.00	1990		FALSE	0
4157	48300	1996	1990	0	-5.00	0		FALSE	0
4158	48300	1997	1990	0	-28.00	0		FALSE	0
4159	48300	1998	1990	0	-28.40	0		FALSE	0
4160	48300	1999	1990	0	-340.80	0		FALSE	0
4161	48300	2000	1990	0	-337.00	0		FALSE	0
4162	48300	2001	1990	0	-1,561.90	0		FALSE	0
4163	48300	2002	1990	0	-2,536.90	0		FALSE	0
4164	48300	2005	1990	0	-3,213.90	0		FALSE	0
4165	48300	2006	1990	0	-3,312.50	0		FALSE	0
4166	48300	2007	1990	0	-3,246.80	0		FALSE	0
4167	48300	2008	1990	0	-2,930.80	0		FALSE	0
4168	48300	2009	1990	0	-4,512.40	0		FALSE	0
4169	48300	2010	1990	0	-2,356.30	0		FALSE	0
4170	48300	2011	1990	0	-1,137.80	0		FALSE	0
4171	48300	2011	1990	8	1,503.14	0		FALSE	0
4172	48300	1996	1991	0	-1.00	0		FALSE	0
4173	48300	1997	1991	0	-7.00	0		FALSE	0
4174	48300	1997	1991	4	2,700.00	1992	Correction 471000	FALSE	0
4175	48300	1998	1991	0	-6.60	0		FALSE	0
4176	48300	1999	1991	0	-164.90	0		FALSE	0
4177	48300	2000	1991	0	-164.30	0		FALSE	0
4178	48300	2001	1991	0	-1,153.60	0		FALSE	0
4179	48300	2002	1991	0	-2,228.80	0		FALSE	0
4180	48300	2005	1991	0	-4,015.40	0		FALSE	0
4181	48300	2006	1991	0	-4,519.10	0		FALSE	0
4182	48300	2007	1991	0	-4,802.00	0		FALSE	0
4183	48300	2008	1991	0	-4,658.20	0		FALSE	0
4184	48300	2009	1991	0	-8,904.00	0		FALSE	0
4185	48300	2010	1991	0	-4,649.60	0		FALSE	0
4186	48300	2011	1991	0	-2,245.20	0		FALSE	0

4187	48300	2011	1991	8	2,966.04	0		FALSE	0
4188	48300	1997	1992	0	-1.00	0		FALSE	0
4189	48300	1997	1992	4	-2,700.00	1992	Correction 471000	FALSE	0
4190	48300	1997	1992	4	4,710.00	1992	Correction 471000	FALSE	0
4191	48300	1998	1992	0	-0.80	0		FALSE	0
4192	48300	1999	1992	0	-36.30	0		FALSE	0
4193	48300	2000	1992	0	-36.30	0		FALSE	0
4194	48300	2001	1992	0	-435.90	0		FALSE	0
4195	48300	2002	1992	0	-1,018.10	0		FALSE	0
4196	48300	2005	1992	0	-1,314.00	0		FALSE	0
4197	48300	2006	1992	0	-1,539.40	0		FALSE	0
4198	48300	2007	1992	0	-1,686.60	0		FALSE	0
4199	48300	2008	1992	0	-1,694.10	0		FALSE	0
4200	48300	2009	1992	0	-3,801.20	0		FALSE	0
4201	48300	2010	1992	0	-1,840.40	0		FALSE	0
4202	48300	2011	1992	0	-820.40	0		FALSE	0
4203	48300	2011	1992	8	909.82	0		FALSE	0
4204	48300	1997	1993	3	-25,205.60	1993		FALSE	0
4205	48300	1999	1993	0	-5.50	0		FALSE	0
4206	48300	2000	1993	0	-5.50	0		FALSE	0
4207	48300	2001	1993	0	-138.40	0		FALSE	0
4208	48300	2002	1993	0	-411.40	0		FALSE	0
4209	48300	2005	1993	0	-17,475.60	0		FALSE	0
4210	48300	2006	1993	0	-15,356.60	0		FALSE	0
4211	48300	2007	1993	0	-271.10	0		FALSE	0
4212	48300	2009	1993	0	-1,136.80	0		FALSE	0
4213	48300	2010	1993	0	-593.60	0		FALSE	0
4214	48300	2011	1993	0	-286.60	0		FALSE	0
4215	48300	2011	1993	8	378.67	0		FALSE	0
4216	48300	1997	1995	3	-25,205.60	1995		FALSE	0
4217	48300	2001	1995	0	-3.00	0		FALSE	0
4218	48300	2002	1995	0	-18.50	0		FALSE	0
4219	48300	2006	1995	0	-2,973.00	0		FALSE	0
4220	48300	2007	1995	0	-15,684.50	0		FALSE	0
4221	48300	2008	1995	0	-1,136.80	0		FALSE	0
4222	48300	2011	1995	8	0.00	0		FALSE	0
4223	48300	1997	1996	3	-35,560.00	1996		FALSE	0
4224	48300	2001	1996	0	-0.50	0		FALSE	0
4225	48300	2002	1996	0	-4.00	0		FALSE	0
4226	48300	2006	1996	0	-131.60	0		FALSE	0
4227	48300	2007	1996	0	-1,290.50	0		FALSE	0
4228	48300	2008	1996	0	-9,708.10	0		FALSE	0
4229	48300	2011	1996	8	7,412.16	0		FALSE	0
4230	48300	2002	1997	0	-0.20	0		FALSE	0
4231	48300	2007	1997	0	-296.50	0		FALSE	0
4232	48300	2008	1997	0	-5,882.70	0		FALSE	0
4233	48300	2011	1997	8	2,902.53	0		FALSE	0
4234	48300	2005	1998	0	-5,553.00	0		FALSE	0
4235	48300	2006	1998	0	-2,689.80	0		FALSE	0
4236	48300	2007	1998	0	-2,480.90	0		FALSE	0
4237	48300	2008	1998	0	-2,204.90	0		FALSE	0
4238	48300	2009	1998	0	-3,154.40	0		FALSE	0
4239	48300	2010	1998	0	-1,630.50	0		FALSE	0

4240	48300	2011	1998	0	-822.50	0	FALSE	0
4241	48300	2011	1998	8	13,797.39	0	FALSE	0
4242	48300	2005	1999	0	-151.00	0	FALSE	0
4243	48300	2006	1999	0	-573.00	0	FALSE	0
4244	48300	2007	1999	0	-755.70	0	FALSE	0
4245	48300	2008	1999	0	-1,357.40	0	FALSE	0
4246	48300	2009	1999	0	-960.90	0	FALSE	0
4247	48300	2010	1999	0	-2,012.70	0	FALSE	0
4248	48300	2011	1999	0	-194.40	0	FALSE	0
4249	48300	2011	1999	8	9,644.27	0	FALSE	0
4250	48300	2011	2000	8	2,749.22	0	FALSE	0
4251	48300	2010	2001	0	-2,241.90	0	FALSE	0
4252	48300	2011	2001	8	5,644.80	0	FALSE	0
4253	48300	2010	2002	0	-2,875.30	0	FALSE	0
4254	48300	2011	2002	8	0.00	0	FALSE	0
4255	48300	2010	2003	0	-102.20	0	FALSE	0
4256	48300	2011	2003	0	-734.10	0	FALSE	0
4257	48300	2011	2003	8	0.00	0	FALSE	0
4258	48300	2009	2004	0	-2,549.70	0	FALSE	0
4259	48300	2010	2004	0	-6,630.50	0	FALSE	0
4260	48300	2011	2004	0	-6,992.00	0	FALSE	0
4261	48300	2011	2004	8	2,243.36	0	FALSE	0
4262	48300	2011	2005	8	10,922.40	0	FALSE	0
4263	48300	2011	2006	8	5,995.34	0	FALSE	0
4264	48300	2011	2007	8	10,018.97	0	FALSE	0
4265	48300	2011	2008	8	10,493.44	0	FALSE	0
4266	48300	2011	2009	8	858.00	0	FALSE	0
4267	48300	2011	2010	8	10,095.47	0	FALSE	0
4268	48300	2011	2011	8	71,272.97	0	FALSE	0
4269	48320	1992	1986	0	-4,800.00	0	FALSE	0
4270	48320	1996	1986	0	-6,029.00	0	FALSE	0
4271	48320	1992	1988	0	-12,610.00	0	FALSE	0
4272	48320	1996	1988	0	-36,261.50	0	FALSE	0
4273	48320	1994	1990	0	-4,200.00	0	FALSE	0
4274	48320	1996	1990	0	-764.50	0	FALSE	0
4275	48320	1994	1991	0	-125.00	0	FALSE	0
4276	48320	1996	1991	0	-6,990.00	0	FALSE	0
4277	48320	1997	1991	0	-5,304.00	0	FALSE	0
4278	48320	1998	1991	0	-873.00	0	FALSE	0
4279	48320	1996	1992	0	-11,620.00	0	FALSE	0
4280	48320	1997	1992	0	-24,072.00	0	FALSE	0
4281	48320	1998	1992	0	-11,234.00	0	FALSE	0
4282	48320	1999	1992	0	-9,927.40	0	FALSE	0
4283	48320	1996	1993	0	-4,660.00	0	FALSE	0
4284	48320	1997	1993	0	-12,480.00	0	FALSE	0
4285	48320	1998	1993	0	-9,924.20	0	FALSE	0
4286	48320	1999	1993	0	-38,524.30	0	FALSE	0
4287	48320	1996	1994	0	-919.00	0	FALSE	0
4288	48320	1997	1994	0	-3,788.00	0	FALSE	0
4289	48320	1998	1994	0	-3,519.20	0	FALSE	0
4290	48320	1999	1994	0	-46,019.50	0	FALSE	0
4291	48320	1996	1995	0	-104.00	0	FALSE	0
4292	48320	1997	1995	0	-693.00	0	FALSE	0

4293	48320	1998	1995	0	-681.80	0	FALSE	0
4294	48320	1999	1995	0	-39,568.40	0	FALSE	0
4295	48320	1997	1996	0	-275.00	0	FALSE	0
4296	48320	1998	1996	0	-273.90	0	FALSE	0
4297	48320	1999	1996	0	-108,015.00	0	FALSE	0
4298	48320	1999	1997	0	-28,638.90	0	FALSE	0
4299	48320	1999	1998	0	-70,237.00	0	FALSE	0
4300	48320	1999	1999	0	-2,789.40	0	FALSE	0
4301	48320	2000	1999	0	-20,521.50	0	FALSE	0
4302	48320	2002	1999	0	-2,982.40	0	FALSE	0
4303	48320	2002	2000	0	-26.40	0	FALSE	0
4304	48320	2001	2001	0	-727.30	0	FALSE	0
4305	48320	2002	2001	0	-4.20	0	FALSE	0
4306	48320	2005	2004	0	-180.40	0	FALSE	0
4307	48320	2006	2004	0	-556.50	0	FALSE	0
4308	48320	2007	2004	0	-2,241.40	0	FALSE	0
4309	48320	2008	2004	0	-6,005.60	0	FALSE	0
4310	48320	2009	2004	0	-23,162.90	0	FALSE	0
4311	48320	2010	2004	0	-49.10	0	FALSE	0
4312	48320	2010	2004	0	-75.10	0	FALSE	0
4313	48320	2011	2004	0	-0.50	0	FALSE	0
4314	48320	2011	2004	8	74.62	0	FALSE	0
4315	48320	2007	2005	0	-85.50	0	FALSE	0
4316	48320	2008	2005	0	-400.30	0	FALSE	0
4317	48320	2009	2005	0	-124.20	0	FALSE	0
4318	48320	2010	2005	0	-4,506.40	0	FALSE	0
4319	48320	2011	2005	8	0.00	0	FALSE	0
4320	48320	2011	2006	0	-74.60	0	FALSE	0
4321	48320	2011	2006	8	2,646.27	0	FALSE	0
4322	48320	2011	2007	8	299.99	0	FALSE	0
4323	48320	2011	2008	8	2,677.00	0	FALSE	0
4324	48320	2011	2009	8	1,308.00	0	FALSE	0
4325	48320	2011	2010	8	4,466.89	0	FALSE	0
4326	48320	2011	2011	8	35,893.75	0	FALSE	0
4327	48400	1985	1970	0	-1,293.90	0 UNIT 23	FALSE	0
4328	48400	1992	1972	0	-652.00	0	FALSE	0
4329	48400	1993	1972	0	-22,475.10	0	FALSE	0
4330	48400	1997	1972	4	652.00	1972	FALSE	0
4331	48400	1981	1973	0	-7,125.00	0 UNIT 27	FALSE	0
4332	48400	1990	1973	0	-1,307.60	0 UNIT 18A	FALSE	0
4333	48400	1980	1974	0	-1,750.00	0 UNIT 12	FALSE	0
4334	48400	1980	1974	0	-1,899.50	0 UNIT 12A	FALSE	0
4335	48400	1986	1974	0	-15,885.00	0 UNIT 3	FALSE	0
4336	48400	1992	1974	0	-1,763.00	0	FALSE	0
4337	48400	1994	1974	0	-652.00	0	FALSE	0
4338	48400	1997	1974	0	-1,000.00	0	FALSE	0
4339	48400	2007	1974	0	-5,604.60	0	FALSE	0
4340	48400	2011	1974	8	0.00	0	FALSE	0
4341	48400	1980	1975	0	-4,565.20	0 UNIT 17	FALSE	0
4342	48400	1981	1975	0	-4,793.00	0 UNIT 14	FALSE	0
4343	48400	1981	1975	0	-5,449.00	0 UNIT 37	FALSE	0
4344	48400	1982	1975	0	-2,866.90	0 UNIT 33A	FALSE	0
4345	48400	1982	1975	0	-5,659.50	0 UNIT 33	FALSE	0

4346	48400	1985	1978	0	-3,223.00	0	UNIT 49A	FALSE	0
4347	48400	1985	1978	0	-3,566.40	0	UNIT 48A	FALSE	0
4348	48400	1989	1978	0	-30,818.00	0	UNIT 5	FALSE	0
4349	48400	1990	1978	0	-3,566.40	0	UNIT 21A	FALSE	0
4350	48400	1992	1978	0	-52,502.00	0		FALSE	0
4351	48400	1993	1978	0	-652.00	0		FALSE	0
4352	48400	1994	1978	0	-4,408.00	0		FALSE	0
4353	48400	1988	1979	0	-4,198.30	0	UNIT 24A	FALSE	0
4354	48400	1994	1979	0	-15,000.00	0		FALSE	0
4355	48400	1992	1980	0	-3,515.00	0		FALSE	0
4356	48400	1985	1981	0	-7,690.00	0	UNIT 63	FALSE	0
4357	48400	1991	1981	0	-44,405.00	0	UNIT 122	FALSE	0
4358	48400	1992	1981	0	-845.20	0		FALSE	0
4359	48400	1997	1981	4	845.17	1981		FALSE	0
4360	48400	1985	1982	0	-8,442.10	0	UNIT 11	FALSE	0
4361	48400	1986	1982	0	-10,637.00	0	UNIT 15	FALSE	0
4362	48400	1988	1982	0	-10,559.50	0	UNIT 13	FALSE	0
4363	48400	1989	1982	0	-10,039.40	0	UNIT 14	FALSE	0
4364	48400	1989	1982	0	-10,763.80	0	UNIT 20	FALSE	0
4365	48400	1990	1982	0	-11,388.60	0	UNIT 16	FALSE	0
4366	48400	1992	1982	0	-32,138.90	0		FALSE	0
4367	48400	1993	1982	0	-845.20	0		FALSE	0
4368	48400	1994	1982	0	-73,329.60	0		FALSE	0
4369	48400	1990	1983	0	-10,569.00	0	UNIT 18	FALSE	0
4370	48400	1988	1984	0	-800.00	0	UNIT 62A	FALSE	0
4371	48400	1988	1984	0	-7,150.00	0	UNIT 141	FALSE	0
4372	48400	1988	1984	0	-10,875.00	0	UNIT 50	FALSE	0
4373	48400	1989	1984	0	-5,126.00	0	UNIT 138	FALSE	0
4374	48400	1991	1984	0	-5,300.00	0	UNIT 137	FALSE	0
4375	48400	2011	1984	8	474.75	0		FALSE	0
4376	48400	1988	1985	0	-10,734.30	0	UNIT 24	FALSE	0
4377	48400	1989	1985	0	-27,679.80	0	UNIT 136	FALSE	0
4378	48400	1990	1985	0	-10,734.30	0	UNIT 21	FALSE	0
4379	48400	1990	1985	0	-10,965.90	0	UNIT 26	FALSE	0
4380	48400	1990	1985	0	-11,462.10	0	UNIT 25	FALSE	0
4381	48400	1991	1985	0	-12,705.40	0	UNIT 11	FALSE	0
4382	48400	1992	1985	0	-14,020.50	0		FALSE	0
4383	48400	1996	1985	0	-6,100.00	0		FALSE	0
4384	48400	2000	1985	0	-12,693.00	0		FALSE	0
4385	48400	2007	1985	0	-17,728.00	0		FALSE	0
4386	48400	2011	1985	8	0.00	0		FALSE	0
4387	48400	1992	1986	0	-27,254.00	0		FALSE	0
4388	48400	1994	1986	0	-2,312.00	0		FALSE	0
4389	48400	1997	1986	0	-5,805.00	0		FALSE	0
4390	48400	2011	1986	8	3,385.00	0		FALSE	0
4391	48400	1988	1987	7	-20,738.00	0	UNIT 39	FALSE	0
4392	48400	1992	1987	0	-31,395.50	0		FALSE	0
4393	48400	1993	1987	0	-34,709.00	0		FALSE	0
4394	48400	1994	1987	0	-34,454.20	0		FALSE	0
4395	48400	1990	1988	0	-16,117.00	0	UNIT 43	FALSE	0
4396	48400	1991	1988	0	-19,400.00	0	UNIT 40	FALSE	0
4397	48400	1992	1988	0	-12,890.10	0		FALSE	0
4398	48400	1993	1988	0	-44,638.70	0		FALSE	0

4399	48400	1994	1988	0	-25,070.00	0	FALSE	0
4400	48400	1996	1988	0	-38,316.40	0	FALSE	0
4401	48400	1998	1988	0	-12,833.00	0	FALSE	0
4402	48400	2007	1988	0	-6,532.90	0	FALSE	0
4403	48400	2011	1988	8	4,868.01	0	FALSE	0
4404	48400	1993	1989	0	-56,035.00	0	FALSE	0
4405	48400	1996	1989	0	-41,006.70	0	FALSE	0
4406	48400	1997	1989	0	-12,100.10	0	FALSE	0
4407	48400	1998	1989	0	-58,429.00	0	FALSE	0
4408	48400	1999	1989	0	-56,915.50	0	FALSE	0
4409	48400	2007	1989	0	-236,564.80	0	FALSE	0
4410	48400	2011	1989	8	34,390.39	0	FALSE	0
4411	48400	1992	1990	0	-1,500.00	0	FALSE	0
4412	48400	1993	1990	0	-43,842.00	0	FALSE	0
4413	48400	1996	1990	0	-48,501.00	0	FALSE	0
4414	48400	1997	1990	0	-6,990.50	0	FALSE	0
4415	48400	1998	1990	0	-27,650.50	0	FALSE	0
4416	48400	2000	1990	0	-13,182.00	0	FALSE	0
4417	48400	2001	1990	0	-26,773.00	0	FALSE	0
4418	48400	2011	1990	8	58.50	0	FALSE	0
4419	48400	1992	1991	0	-13,646.00	0	FALSE	0
4420	48400	1994	1991	0	-19,624.30	0	FALSE	0
4421	48400	1998	1991	0	-142,746.40	0	FALSE	0
4422	48400	1999	1991	0	-17,959.00	0	FALSE	0
4423	48400	2011	1991	8	12,221.00	0	FALSE	0
4424	48400	1996	1992	0	-16,901.00	0	FALSE	0
4425	48400	1997	1992	0	-5,900.00	0	FALSE	0
4426	48400	1998	1992	0	-131,149.70	0	FALSE	0
4427	48400	2000	1992	0	-19,692.00	0	FALSE	0
4428	48400	2009	1992	0	-37,278.10	0	FALSE	0
4429	48400	2011	1992	8	0.00	0	FALSE	0
4430	48400	1998	1993	0	-100,074.00	0	FALSE	0
4431	48400	2000	1993	0	-25,844.00	0	FALSE	0
4432	48400	2001	1993	0	-25,777.00	0	FALSE	0
4433	48400	2011	1993	8	32,789.25	0	FALSE	0
4434	48400	1997	1994	4	8,761.68	1994	FALSE	0
4435	48400	2001	1994	0	-29,895.00	0	FALSE	0
4436	48400	2008	1994	0	-1,124.00	0	FALSE	0
4437	48400	2009	1994	0	-17,869.00	0	FALSE	0
4438	48400	2010	1994	0	-4,005.60	0	FALSE	0
4439	48400	2011	1994	8	156,818.41	0	FALSE	0
4440	48400	1997	1995	4	6,699.00	1995	FALSE	0
4441	48400	1998	1995	0	-32,573.70	0	FALSE	0
4442	48400	2002	1995	0	-94,235.70	0	FALSE	0
4443	48400	2007	1995	0	-974.90	0	FALSE	0
4444	48400	2009	1995	0	-27,273.70	0	FALSE	0
4445	48400	2010	1995	0	-24,484.60	0	FALSE	0
4446	48400	2011	1995	8	15,460.68	0	FALSE	0
4447	48400	1998	1996	0	-62,467.00	0	FALSE	0
4448	48400	2011	1996	8	173,521.43	0	FALSE	0
4449	48400	1998	1997	0	-95,862.40	0	FALSE	0
4450	48400	2008	1997	0	-858.00	0	FALSE	0
4451	48400	2009	1997	0	-25,808.00	0	FALSE	0

4452	48400	2011	1997	0	-4,517.00	0	FALSE	0
4453	48400	2011	1997	8	66,433.55	0	FALSE	0
4454	48400	1998	1998	0	-12,221.00	0	FALSE	0
4455	48400	2002	1998	0	-74,004.50	0	FALSE	0
4456	48400	2010	1998	0	-9,778.40	0	FALSE	0
4457	48400	2011	1998	8	13,106.81	0	FALSE	0
4458	48400	2010	1999	0	-4,649.30	0	FALSE	0
4459	48400	2011	1999	8	122,619.76	0	FALSE	0
4460	48400	2000	2000	0	-14,671.00	0	FALSE	0
4461	48400	2000	2000	4	23,350.83	2000	FALSE	0
4462	48400	2011	2000	8	8,679.83	0	FALSE	0
4463	48400	2001	2001	0	-15,239.20	0	FALSE	0
4464	48400	2010	2001	0	-95,180.90	0	FALSE	0
4465	48400	2011	2001	8	244,021.20	0	FALSE	0
4466	48400	2010	2002	0	-1,767.20	0	FALSE	0
4467	48400	2011	2002	8	195,342.59	0	FALSE	0
4468	48400	2007	2003	0	-16,195.00	0	FALSE	0
4469	48400	2011	2003	8	8,923.42	0	FALSE	0
4470	48400	2008	2004	0	-1,100.10	0	FALSE	0
4471	48400	2010	2004	0	-14,114.00	0	FALSE	0
4472	48400	2011	2004	8	14,617.59	0	FALSE	0
4473	48400	2011	2005	8	166,758.22	0	FALSE	0
4474	48400	2007	2006	0	-4,935.20	0	FALSE	0
4475	48400	2010	2006	0	-71.00	0	FALSE	0
4476	48400	2011	2006	8	151,016.59	0	FALSE	0
4477	48400	2008	2007	0	-41,096.90	0	FALSE	0
4478	48400	2008	2007	3	-380.90	2007	FALSE	0
4479	48400	2011	2007	8	470,336.39	0	FALSE	0
4480	48400	2009	2008	4	2,404.24	0	FALSE	0
4481	48400	2011	2008	8	137,140.79	0	FALSE	0
4482	48400	2010	2009	4	18,332.99	0	FALSE	0
4483	48400	2011	2009	3	-1,544.30	2009	FALSE	0
4484	48400	2011	2009	8	165,961.58	0	FALSE	0
4485	48400	2011	2010	4	158,554.74	2010	FALSE	0
4486	48400	2011	2010	8	308,325.84	0	FALSE	0
4487	48400	2011	2011	8	53,875.44	0	FALSE	0
4488	48500	1960	1957	0	-815.00	0	FALSE	0
4489	48500	1962	1957	0	-2,075.00	0	FALSE	0
4490	48500	1968	1957	0	-747.00	0	FALSE	0
4491	48500	1970	1957	0	-1,200.00	0	FALSE	0
4492	48500	1972	1957	0	-560.00	0	FALSE	0
4493	48500	1987	1957	4	2,331.20	1957	FALSE	0
4494	48500	1988	1957	0	-2,331.20	0	FALSE	0
4495	48500	1989	1957	0	0.00	0	FALSE	0
4496	48500	1987	1958	4	47.20	1958	FALSE	0
4497	48500	1988	1958	0	-47.20	0	FALSE	0
4498	48500	1989	1958	0	0.00	0	FALSE	0
4499	48500	1960	1959	0	-1,703.00	0	FALSE	0
4500	48500	1964	1959	0	-361.00	0	FALSE	0
4501	48500	1965	1959	0	-18.00	0	FALSE	0
4502	48500	1967	1959	0	-3.00	0	FALSE	0
4503	48500	1980	1959	0	-600.00	0	FALSE	0
4504	48500	1982	1959	0	-127.00	0	FALSE	0

4505	48500	1983	1959	0	-13.00	0	FALSE	0
4506	48500	1987	1959	4	122.00	1959	FALSE	0
4507	48500	1988	1959	0	-122.00	0	FALSE	0
4508	48500	1989	1959	0	0.00	0	FALSE	0
4509	48500	1962	1960	0	-8.00	0	FALSE	0
4510	48500	1963	1960	0	-11.00	0	FALSE	0
4511	48500	1964	1960	0	-271.00	0	FALSE	0
4512	48500	1965	1960	0	-123.00	0	FALSE	0
4513	48500	1966	1960	0	-8.00	0	FALSE	0
4514	48500	1967	1960	0	-35.00	0	FALSE	0
4515	48500	1968	1960	0	-475.00	0	FALSE	0
4516	48500	1972	1960	0	-2,993.00	0	FALSE	0
4517	48500	1982	1960	0	-1,390.00	0	FALSE	0
4518	48500	1983	1960	0	-221.00	0	FALSE	0
4519	48500	1984	1960	0	-24.00	0	FALSE	0
4520	48500	1987	1960	4	461.50	1960	FALSE	0
4521	48500	1988	1960	0	-461.50	0	FALSE	0
4522	48500	1989	1960	0	0.00	0	FALSE	0
4523	48500	1961	1961	0	-762.00	0	FALSE	0
4524	48500	1962	1961	0	-94.00	0	FALSE	0
4525	48500	1963	1961	0	-26.00	0	FALSE	0
4526	48500	1964	1961	0	-27.00	0	FALSE	0
4527	48500	1967	1961	0	-77.00	0	FALSE	0
4528	48500	1968	1961	0	-17.00	0	FALSE	0
4529	48500	1972	1961	0	-3,668.00	0	FALSE	0
4530	48500	1982	1961	0	-1,126.00	0	FALSE	0
4531	48500	1983	1961	0	-239.00	0	FALSE	0
4532	48500	1984	1961	0	-38.00	0	FALSE	0
4533	48500	1987	1961	4	135.20	1961	FALSE	0
4534	48500	1988	1961	0	-135.20	0	FALSE	0
4535	48500	1989	1961	0	0.00	0	FALSE	0
4536	48500	1963	1962	0	-6.00	0	FALSE	0
4537	48500	1967	1962	0	-90.00	0	FALSE	0
4538	48500	1972	1962	0	-1,124.00	0	FALSE	0
4539	48500	1982	1962	0	-661.00	0	FALSE	0
4540	48500	1983	1962	0	-176.00	0	FALSE	0
4541	48500	1984	1962	0	-37.00	0	FALSE	0
4542	48500	1987	1962	4	421.00	1962	FALSE	0
4543	48500	1988	1962	0	-421.00	0	FALSE	0
4544	48500	1989	1962	0	0.00	0	FALSE	0
4545	48500	1966	1963	0	-13.00	0	FALSE	0
4546	48500	1967	1963	0	-4.00	0	FALSE	0
4547	48500	1968	1963	0	-35.00	0	FALSE	0
4548	48500	1972	1963	0	-564.00	0	FALSE	0
4549	48500	1982	1963	0	-867.00	0	FALSE	0
4550	48500	1983	1963	0	-278.00	0	FALSE	0
4551	48500	1984	1963	0	-74.00	0	FALSE	0
4552	48500	1987	1963	4	58.70	1963	FALSE	0
4553	48500	1988	1963	0	-58.70	0	FALSE	0
4554	48500	1989	1963	0	0.00	0	FALSE	0
4555	48500	1966	1964	0	-50.00	0	FALSE	0
4556	48500	1967	1964	0	-43.00	0	FALSE	0
4557	48500	1970	1964	0	-431.00	0	FALSE	0

4558	48500	1972	1964	0	-258.00	0		FALSE	0
4559	48500	1982	1964	0	-868.00	0		FALSE	0
4560	48500	1983	1964	0	-327.00	0		FALSE	0
4561	48500	1984	1964	0	-105.00	0		FALSE	0
4562	48500	1987	1964	4	544.30	1964		FALSE	0
4563	48500	1988	1964	0	-518.00	0		FALSE	0
4564	48500	1989	1964	0	-27.00	0		FALSE	0
4565	48500	1966	1965	0	-42.00	0		FALSE	0
4566	48500	1972	1965	0	-113.00	0		FALSE	0
4567	48500	1982	1965	0	-127.00	0		FALSE	0
4568	48500	1983	1965	0	-55.00	0		FALSE	0
4569	48500	1984	1965	0	-20.00	0		FALSE	0
4570	48500	1987	1965	4	351.48	1965		FALSE	0
4571	48500	1988	1965	0	-316.00	0		FALSE	0
4572	48500	1989	1965	0	-33.00	0		FALSE	0
4573	48500	1990	1965	0	-1.80	0		FALSE	0
4574	48500	1991	1965	0	-1.80	0		FALSE	0
4575	48500	1972	1966	0	-177.00	0		FALSE	0
4576	48500	1982	1966	0	-546.00	0		FALSE	0
4577	48500	1983	1966	0	-268.00	0		FALSE	0
4578	48500	1984	1966	0	-116.00	0		FALSE	0
4579	48500	1985	1966	0	-106.00	0		FALSE	0
4580	48500	1986	1966	0	-24.00	0		FALSE	0
4581	48500	1987	1966	0	-8.00	0		FALSE	0
4582	48500	1989	1966	0	0.00	0		FALSE	0
4583	48500	1972	1967	0	-138.00	0		FALSE	0
4584	48500	1982	1967	0	-1,454.00	0		FALSE	0
4585	48500	1983	1967	0	-800.00	0		FALSE	0
4586	48500	1984	1967	0	-393.00	0		FALSE	0
4587	48500	1985	1967	0	-170.00	0		FALSE	0
4588	48500	1986	1967	0	-64.00	0		FALSE	0
4589	48500	1987	1967	0	-28.00	0		FALSE	0
4590	48500	1987	1967	4	1,202.47	1967		FALSE	0
4591	48500	1988	1967	0	-962.00	0		FALSE	0
4592	48500	1989	1967	0	-204.00	0		FALSE	0
4593	48500	1990	1967	0	-32.50	0		FALSE	0
4594	48500	1991	1967	0	-3.60	0		FALSE	0
4595	48500	1972	1968	0	-43.00	0		FALSE	0
4596	48500	1982	1968	0	-2,128.00	0		FALSE	0
4597	48500	1983	1968	0	-1,300.00	0		FALSE	0
4598	48500	1984	1968	0	-715.00	0		FALSE	0
4599	48500	1985	1968	0	-351.00	0		FALSE	0
4600	48500	1986	1968	0	-152.00	0		FALSE	0
4601	48500	1987	1968	0	-57.00	0		FALSE	0
4602	48500	1988	1968	0	-25.00	0		FALSE	0
4603	48500	1989	1968	0	0.00	0		FALSE	0
4604	48500	1982	1969	0	-588.00	0		FALSE	0
4605	48500	1983	1969	0	-397.00	0		FALSE	0
4606	48500	1984	1969	0	-243.00	0		FALSE	0
4607	48500	1985	1969	0	-133.00	0		FALSE	0
4608	48500	1986	1969	0	-65.00	0		FALSE	0
4609	48500	1987	1969	0	-29.00	0		FALSE	0
4610	48500	1988	1969	0	-15.00	0		FALSE	0

4611	48500	1989	1969	0	0.00	0	FALSE	0
4612	48500	1982	1970	0	-835.00	0	FALSE	0
4613	48500	1983	1970	0	-620.00	0	FALSE	0
4614	48500	1984	1970	0	-418.00	0	FALSE	0
4615	48500	1985	1970	0	-256.00	0	FALSE	0
4616	48500	1986	1970	0	-141.00	0	FALSE	0
4617	48500	1987	1970	0	-69.00	0	FALSE	0
4618	48500	1988	1970	0	-46.00	0	FALSE	0
4619	48500	1989	1970	0	0.00	0	FALSE	0
4620	48500	1973	1971	0	-186.00	0	FALSE	0
4621	48500	1978	1971	0	-184.00	0	FALSE	0
4622	48500	1982	1971	0	-316.00	0	FALSE	0
4623	48500	1983	1971	0	-259.00	0	FALSE	0
4624	48500	1984	1971	0	-192.00	0	FALSE	0
4625	48500	1985	1971	0	-130.00	0	FALSE	0
4626	48500	1986	1971	0	-79.00	0	FALSE	0
4627	48500	1987	1971	0	-43.00	0	FALSE	0
4628	48500	1987	1971	4	186.93	1971	FALSE	0
4629	48500	1988	1971	0	-132.00	0	FALSE	0
4630	48500	1989	1971	0	-57.00	0	FALSE	0
4631	48500	1990	1971	0	-21.50	0	FALSE	0
4632	48500	1991	1971	0	-9.20	0	FALSE	0
4633	48500	1982	1972	0	-1,043.00	0	FALSE	0
4634	48500	1983	1972	0	-938.00	0	FALSE	0
4635	48500	1984	1972	0	-766.00	0	FALSE	0
4636	48500	1985	1972	0	-570.00	0	FALSE	0
4637	48500	1986	1972	0	-384.00	0	FALSE	0
4638	48500	1987	1972	0	-235.00	0	FALSE	0
4639	48500	1988	1972	0	-129.00	0	FALSE	0
4640	48500	1989	1972	0	-63.00	0	FALSE	0
4641	48500	1990	1972	0	-27.50	0	FALSE	0
4642	48500	1991	1972	0	-14.80	0	FALSE	0
4643	48500	1982	1973	0	-1,079.00	0	FALSE	0
4644	48500	1983	1973	0	-1,078.00	0	FALSE	0
4645	48500	1984	1973	0	-971.00	0	FALSE	0
4646	48500	1985	1973	0	-793.00	0	FALSE	0
4647	48500	1986	1973	0	-589.00	0	FALSE	0
4648	48500	1987	1973	0	-397.00	0	FALSE	0
4649	48500	1988	1973	0	-243.00	0	FALSE	0
4650	48500	1989	1973	0	-133.00	0	FALSE	0
4651	48500	1990	1973	0	-65.60	0	FALSE	0
4652	48500	1991	1973	0	-28.40	0	FALSE	0
4653	48500	1992	1973	0	-15.30	0	FALSE	0
4654	48500	1982	1974	0	-639.00	0	FALSE	0
4655	48500	1983	1974	0	-725.00	0	FALSE	0
4656	48500	1984	1974	0	-725.00	0	FALSE	0
4657	48500	1985	1974	0	-652.00	0	FALSE	0
4658	48500	1986	1974	0	-533.00	0	FALSE	0
4659	48500	1987	1974	0	-396.00	0	FALSE	0
4660	48500	1988	1974	0	-267.00	0	FALSE	0
4661	48500	1989	1974	0	-163.00	0	FALSE	0
4662	48500	1990	1974	0	-89.80	0	FALSE	0
4663	48500	1991	1974	0	-44.10	0	FALSE	0

4664	48500	1992	1974	0	-29.40	0	FALSE	0
4665	48500	1982	1975	0	-163.00	0	FALSE	0
4666	48500	1983	1975	0	-220.00	0	FALSE	0
4667	48500	1984	1975	0	-249.00	0	FALSE	0
4668	48500	1985	1975	0	-249.00	0	FALSE	0
4669	48500	1986	1975	0	-224.00	0	FALSE	0
4670	48500	1987	1975	0	-183.00	0	FALSE	0
4671	48500	1988	1975	0	-136.00	0	FALSE	0
4672	48500	1989	1975	0	-92.00	0	FALSE	0
4673	48500	1990	1975	0	-56.20	0	FALSE	0
4674	48500	1991	1975	0	-30.90	0	FALSE	0
4675	48500	1992	1975	0	-25.30	0	FALSE	0
4676	48500	1982	1976	0	-108.00	0	FALSE	0
4677	48500	1983	1976	0	-205.00	0	FALSE	0
4678	48500	1984	1976	0	-277.00	0	FALSE	0
4679	48500	1985	1976	0	-314.00	0	FALSE	0
4680	48500	1986	1976	0	-314.00	0	FALSE	0
4681	48500	1987	1976	0	-282.00	0	FALSE	0
4682	48500	1988	1976	0	-230.00	0	FALSE	0
4683	48500	1989	1976	0	-171.00	0	FALSE	0
4684	48500	1990	1976	0	-115.50	0	FALSE	0
4685	48500	1991	1976	0	-70.60	0	FALSE	0
4686	48500	1992	1976	0	-70.60	0	FALSE	0
4687	48500	1983	1977	0	-184.00	0	FALSE	0
4688	48500	1984	1977	0	-349.00	0	FALSE	0
4689	48500	1985	1977	0	-471.00	0	FALSE	0
4690	48500	1986	1977	0	-534.00	0	FALSE	0
4691	48500	1987	1977	0	-535.00	0	FALSE	0
4692	48500	1988	1977	0	-481.00	0	FALSE	0
4693	48500	1989	1977	0	-393.00	0	FALSE	0
4694	48500	1990	1977	0	-291.80	0	FALSE	0
4695	48500	1991	1977	0	-197.00	0	FALSE	0
4696	48500	1992	1977	0	-240.80	0	FALSE	0
4697	48500	1984	1978	0	-708.00	0	FALSE	0
4698	48500	1985	1978	0	-1,345.00	0	FALSE	0
4699	48500	1986	1978	0	-1,816.00	0	FALSE	0
4700	48500	1987	1978	0	-2,058.00	0	FALSE	0
4701	48500	1987	1978	4	433.80	1978	FALSE	0
4702	48500	1988	1978	0	-2,167.00	0	FALSE	0
4703	48500	1989	1978	0	-1,950.00	0	FALSE	0
4704	48500	1990	1978	0	-1,592.60	0	FALSE	0
4705	48500	1991	1978	0	-1,183.10	0	FALSE	0
4706	48500	1992	1978	0	-1,774.70	0	FALSE	0
4707	48500	1985	1979	0	-244.00	0	FALSE	0
4708	48500	1986	1979	0	-464.00	0	FALSE	0
4709	48500	1987	1979	0	-626.00	0	FALSE	0
4710	48500	1988	1979	0	-710.00	0	FALSE	0
4711	48500	1989	1979	0	-710.00	0	FALSE	0
4712	48500	1990	1979	0	-638.80	0	FALSE	0
4713	48500	1991	1979	0	-521.70	0	FALSE	0
4714	48500	1992	1979	0	-968.80	0	FALSE	0
4715	48500	1986	1980	0	-460.00	0	FALSE	0
4716	48500	1987	1980	0	-874.00	0	FALSE	0

4717	48500	1988	1980	0	-1,180.00	0	FALSE	0
4718	48500	1989	1980	0	-1,338.00	0	FALSE	0
4719	48500	1990	1980	0	-1,337.80	0	FALSE	0
4720	48500	1991	1980	0	-1,204.10	0	FALSE	0
4721	48500	1992	1980	0	-2,809.50	0	FALSE	0
4722	48500	1987	1981	0	-187.00	0	FALSE	0
4723	48500	1988	1981	0	-355.00	0	FALSE	0
4724	48500	1989	1981	0	-479.00	0	FALSE	0
4725	48500	1990	1981	0	-543.50	0	FALSE	0
4726	48500	1991	1981	0	-543.50	0	FALSE	0
4727	48500	1992	1981	0	-1,630.40	0	FALSE	0
4728	48500	1988	1982	0	-761.00	0	FALSE	0
4729	48500	1989	1982	0	-1,445.00	0	FALSE	0
4730	48500	1990	1982	0	-1,951.20	0	FALSE	0
4731	48500	1991	1982	0	-2,211.40	0	FALSE	0
4732	48500	1992	1982	0	-3,032.30	0	FALSE	0
4733	48500	1993	1982	0	-3,462.90	0	FALSE	0
4734	48500	1994	1982	0	-822.60	0	FALSE	0
4735	48500	1995	1982	0	-611.00	0	FALSE	0
4736	48500	1996	1982	0	-552.00	0	FALSE	0
4737	48500	1997	1982	0	-256.00	0	FALSE	0
4738	48500	1998	1982	0	-108.50	0	FALSE	0
4739	48500	1989	1983	0	-603.00	0	FALSE	0
4740	48500	1990	1983	0	-1,146.10	0	FALSE	0
4741	48500	1991	1983	0	-1,547.20	0	FALSE	0
4742	48500	1993	1983	0	-2,191.90	0	FALSE	0
4743	48500	1994	1983	0	-1,972.70	0	FALSE	0
4744	48500	1995	1983	0	-1,611.00	0	FALSE	0
4745	48500	1996	1983	0	-1,523.00	0	FALSE	0
4746	48500	1997	1983	0	-884.00	0	FALSE	0
4747	48500	1998	1983	0	-584.90	0	FALSE	0
4748	48500	1990	1984	0	-441.60	0	FALSE	0
4749	48500	1991	1984	0	-839.00	0	FALSE	0
4750	48500	1993	1984	0	-1,510.30	0	FALSE	0
4751	48500	1994	1984	0	-1,510.30	0	FALSE	0
4752	48500	1995	1984	0	-1,359.20	0	FALSE	0
4753	48500	1996	1984	0	-1,342.00	0	FALSE	0
4754	48500	1997	1984	0	-932.00	0	FALSE	0
4755	48500	1998	1984	0	-457.00	0	FALSE	0
4756	48500	1999	1984	0	-440.50	0	FALSE	0
4757	48500	1991	1985	0	-389.50	0	FALSE	0
4758	48500	1993	1985	0	-1,110.10	0	FALSE	0
4759	48500	1994	1985	0	-1,258.10	0	FALSE	0
4760	48500	1995	1985	0	-1,258.10	0	FALSE	0
4761	48500	1996	1985	0	-1,295.00	0	FALSE	0
4762	48500	1997	1985	0	-1,049.00	0	FALSE	0
4763	48500	1998	1985	0	-605.20	0	FALSE	0
4764	48500	1999	1985	0	-496.30	0	FALSE	0
4765	48500	2000	1985	0	-328.80	0	FALSE	0
4766	48500	1993	1986	0	-3,743.20	0	FALSE	0
4767	48500	1994	1986	0	-5,053.30	0	FALSE	0
4768	48500	1995	1986	0	-5,727.00	0	FALSE	0
4769	48500	1996	1986	0	-6,156.00	0	FALSE	0

4770	48500	1997	1986	0	-5,747.00	0	FALSE	0
4771	48500	1998	1986	0	-3,775.30	0	FALSE	0
4772	48500	1999	1986	0	-3,681.00	0	FALSE	0
4773	48500	2000	1986	0	-2,134.60	0	FALSE	0
4774	48500	2001	1986	0	-990.00	0	FALSE	0
4775	48500	2002	1986	0	-424.10	0	FALSE	0
4776	48500	1993	1987	0	-1,906.80	0	FALSE	0
4777	48500	1994	1987	0	-3,622.80	0	FALSE	0
4778	48500	1995	1987	0	-4,890.80	0	FALSE	0
4779	48500	1996	1987	0	-5,558.00	0	FALSE	0
4780	48500	1997	1987	0	-5,954.00	0	FALSE	0
4781	48500	1998	1987	0	-4,354.10	0	FALSE	0
4782	48500	1999	1987	0	-5,013.60	0	FALSE	0
4783	48500	2000	1987	0	-3,479.90	0	FALSE	0
4784	48500	2001	1987	0	-2,017.90	0	FALSE	0
4785	48500	2002	1987	0	-935.90	0	FALSE	0
4786	48500	1994	1988	0	-1,278.00	0	FALSE	0
4787	48500	1995	1988	0	-2,430.00	0	FALSE	0
4788	48500	1996	1988	0	-3,057.00	0	FALSE	0
4789	48500	1997	1988	0	-3,773.00	0	FALSE	0
4790	48500	1998	1988	0	-3,016.30	0	FALSE	0
4791	48500	1999	1988	0	-4,124.80	0	FALSE	0
4792	48500	2000	1988	0	-3,342.50	0	FALSE	0
4793	48500	2001	1988	0	-2,320.00	0	FALSE	0
4794	48500	2002	1988	0	-1,345.40	0	FALSE	0
4795	48500	2005	1988	0	-267.30	0	FALSE	0
4796	48500	2011	1988	8	0.00	0	FALSE	0
4797	48500	1995	1989	0	-3,073.40	0	FALSE	0
4798	48500	1996	1989	0	-5,165.00	0	FALSE	0
4799	48500	1997	1989	0	-7,441.00	0	FALSE	0
4800	48500	1998	1989	0	-6,401.20	0	FALSE	0
4801	48500	1999	1989	0	-10,584.50	0	FALSE	0
4802	48500	2000	1989	0	-9,880.70	0	FALSE	0
4803	48500	2001	1989	0	-8,006.80	0	FALSE	0
4804	48500	2002	1989	0	-5,557.40	0	FALSE	0
4805	48500	2005	1989	0	-237.10	0	FALSE	0
4806	48500	2007	1989	0	-1,897.70	0	FALSE	0
4807	48500	2011	1989	8	0.00	0	FALSE	0
4808	48500	1996	1990	0	-4,739.00	0	FALSE	0
4809	48500	1997	1990	0	-8,172.00	0	FALSE	0
4810	48500	1998	1990	0	-7,448.90	0	FALSE	0
4811	48500	1999	1990	0	-15,395.70	0	FALSE	0
4812	48500	2000	1990	0	-16,492.50	0	FALSE	0
4813	48500	2001	1990	0	-15,395.90	0	FALSE	0
4814	48500	2002	1990	0	-12,475.90	0	FALSE	0
4815	48500	2005	1990	0	-2,471.10	0	FALSE	0
4816	48500	2006	1990	0	-2,243.70	0	FALSE	0
4817	48500	2007	1990	0	-3,633.30	0	FALSE	0
4818	48500	2011	1990	8	0.00	0	FALSE	0
4819	48500	1996	1991	0	-1,936.00	0	FALSE	0
4820	48500	1997	1991	0	-4,175.00	0	FALSE	0
4821	48500	1998	1991	0	-3,971.60	0	FALSE	0
4822	48500	1999	1991	0	-10,824.90	0	FALSE	0

4823	48500	2000	1991	0	-13,357.90	0	FALSE	0
4824	48500	2001	1991	0	-14,309.50	0	FALSE	0
4825	48500	2002	1991	0	-13,358.10	0	FALSE	0
4826	48500	2005	1991	0	-3,495.20	0	FALSE	0
4827	48500	2006	1991	0	-2,752.30	0	FALSE	0
4828	48500	2007	1991	0	-50.90	0	FALSE	0
4829	48500	2008	1991	0	-1,607.00	0	FALSE	0
4830	48500	2009	1991	0	-1,320.80	0	FALSE	0
4831	48500	2010	1991	0	-987.20	0	FALSE	0
4832	48500	2011	1991	0	-1,304.70	0	FALSE	0
4833	48500	2011	1991	8	3,238.21	0	FALSE	0
4834	48500	1996	1992	0	-597.00	0	FALSE	0
4835	48500	1997	1992	0	-1,738.00	0	FALSE	0
4836	48500	1998	1992	0	-1,699.20	0	FALSE	0
4837	48500	1999	1992	0	-6,641.30	0	FALSE	0
4838	48500	2000	1992	0	-9,568.50	0	FALSE	0
4839	48500	2001	1992	0	-11,807.50	0	FALSE	0
4840	48500	2002	1992	0	-12,648.70	0	FALSE	0
4841	48500	2005	1992	0	-876.50	0	FALSE	0
4842	48500	2006	1992	0	-1,215.40	0	FALSE	0
4843	48500	2007	1992	0	-656.00	0	FALSE	0
4844	48500	2008	1992	0	-906.50	0	FALSE	0
4845	48500	2009	1992	0	-450.40	0	FALSE	0
4846	48500	2010	1992	0	-47.70	0	FALSE	0
4847	48500	2011	1992	0	-62.50	0	FALSE	0
4848	48500	2011	1992	8	156.97	0	FALSE	0
4849	48500	1996	1993	0	-64.00	0	FALSE	0
4850	48500	1997	1993	0	-287.00	0	FALSE	0
4851	48500	1998	1993	0	-285.20	0	FALSE	0
4852	48500	1999	1993	0	-1,831.30	0	FALSE	0
4853	48500	2000	1993	0	-3,158.00	0	FALSE	0
4854	48500	2001	1993	0	-4,549.90	0	FALSE	0
4855	48500	2002	1993	0	-5,614.60	0	FALSE	0
4856	48500	2005	1993	0	-5,605.50	0	FALSE	0
4857	48500	2006	1993	0	-1,431.40	0	FALSE	0
4858	48500	2007	1993	0	-3,527.30	0	FALSE	0
4859	48500	2008	1993	0	-1,142.00	0	FALSE	0
4860	48500	2009	1993	0	-2,460.60	0	FALSE	0
4861	48500	2010	1993	0	-392.90	0	FALSE	0
4862	48500	2011	1993	0	-519.00	0	FALSE	0
4863	48500	2011	1993	8	1,288.17	0	FALSE	0
4864	48500	1996	1994	0	-8.00	0	FALSE	0
4865	48500	1997	1994	0	-78.00	0	FALSE	0
4866	48500	1998	1994	0	-77.70	0	FALSE	0
4867	48500	1999	1994	0	-1,022.00	0	FALSE	0
4868	48500	2000	1994	0	-2,203.40	0	FALSE	0
4869	48500	2001	1994	0	-3,799.60	0	FALSE	0
4870	48500	2002	1994	0	-5,474.30	0	FALSE	0
4871	48500	2005	1994	0	-17,640.60	0	FALSE	0
4872	48500	2006	1994	0	-1,650.20	0	FALSE	0
4873	48500	2007	1994	0	-304.40	0	FALSE	0
4874	48500	2008	1994	0	-1,240.00	0	FALSE	0
4875	48500	2009	1994	0	-566.00	0	FALSE	0

4876	48500	2010	1994	0	-1,227.90	0	FALSE	0
4877	48500	2011	1994	0	-1,234.80	0	FALSE	0
4878	48500	2011	1994	8	3,064.70	0	FALSE	0
4879	48500	1997	1995	0	-3.00	0	FALSE	0
4880	48500	1998	1995	0	-3.40	0	FALSE	0
4881	48500	1999	1995	0	-144.30	0	FALSE	0
4882	48500	2000	1995	0	-420.50	0	FALSE	0
4883	48500	2001	1995	0	-906.70	0	FALSE	0
4884	48500	2002	1995	0	-1,563.50	0	FALSE	0
4885	48500	2005	1995	0	-4,634.20	0	FALSE	0
4886	48500	2006	1995	0	-4,866.60	0	FALSE	0
4887	48500	2007	1995	0	-619.40	0	FALSE	0
4888	48500	2008	1995	0	-535.30	0	FALSE	0
4889	48500	2010	1995	0	-1,319.30	0	FALSE	0
4890	48500	2011	1995	0	-815.20	0	FALSE	0
4891	48500	2011	1995	8	1,070.05	0	FALSE	0
4892	48500	1999	1996	0	-87.30	0	FALSE	0
4893	48500	2000	1996	0	-391.30	0	FALSE	0
4894	48500	2001	1996	0	-1,140.10	0	FALSE	0
4895	48500	2002	1996	0	-2,458.00	0	FALSE	0
4896	48500	2005	1996	0	-8,006.10	0	FALSE	0
4897	48500	2006	1996	0	-14,430.80	0	FALSE	0
4898	48500	2007	1996	0	-9,486.20	0	FALSE	0
4899	48500	2008	1996	0	-1,398.70	0	FALSE	0
4900	48500	2011	1996	0	-321.30	0	FALSE	0
4901	48500	2011	1996	8	10,038.84	0	FALSE	0
4902	48500	1999	1997	0	-6.70	0	FALSE	0
4903	48500	2000	1997	0	-62.80	0	FALSE	0
4904	48500	2001	1997	0	-281.50	0	FALSE	0
4905	48500	2002	1997	0	-820.20	0	FALSE	0
4906	48500	2005	1997	0	-4,404.50	0	FALSE	0
4907	48500	2006	1997	0	-4,420.80	0	FALSE	0
4908	48500	2007	1997	0	-8,722.70	0	FALSE	0
4909	48500	2008	1997	0	-8,109.30	0	FALSE	0
4910	48500	2011	1997	8	8,816.70	0	FALSE	0
4911	48500	2000	1998	0	-11.40	0	FALSE	0
4912	48500	2001	1998	0	-106.90	0	FALSE	0
4913	48500	2002	1998	0	-479.10	0	FALSE	0
4914	48500	2005	1998	0	-2,359.20	0	FALSE	0
4915	48500	2006	1998	0	-3,045.80	0	FALSE	0
4916	48500	2007	1998	0	-3,149.90	0	FALSE	0
4917	48500	2008	1998	0	-2,357.30	0	FALSE	0
4918	48500	2011	1998	8	18,273.33	0	FALSE	0
4919	48500	2001	1999	0	-20.00	0	FALSE	0
4920	48500	2002	1999	0	-187.10	0	FALSE	0
4921	48500	2005	1999	0	-6,244.00	0	FALSE	0
4922	48500	2006	1999	0	-8,134.20	0	FALSE	0
4923	48500	2007	1999	0	-6,827.20	0	FALSE	0
4924	48500	2008	1999	0	-11,575.50	0	FALSE	0
4925	48500	2009	1999	0	-5,438.80	0	FALSE	0
4926	48500	2010	1999	0	-4,600.10	0	FALSE	0
4927	48500	2011	1999	0	-2,995.60	0	FALSE	0
4928	48500	2011	1999	8	63,438.59	0	FALSE	0

4929	48500	2002	2000	0	-4.20	0	FALSE	0
4930	48500	2005	2000	0	-3,529.30	0	FALSE	0
4931	48500	2006	2000	0	-7,196.20	0	FALSE	0
4932	48500	2007	2000	0	-1,397.30	0	FALSE	0
4933	48500	2008	2000	0	-4,010.40	0	FALSE	0
4934	48500	2011	2000	0	-0.50	0	FALSE	0
4935	48500	2011	2000	8	6,165.19	0	FALSE	0
4936	48500	2001	2001	0	0.00	0	FALSE	0
4937	48500	2005	2001	0	-449.30	0	FALSE	0
4938	48500	2006	2001	0	-389.10	0	FALSE	0
4939	48500	2007	2001	0	-355.70	0	FALSE	0
4940	48500	2008	2001	0	-569.40	0	FALSE	0
4941	48500	2009	2001	0	-87.40	0	FALSE	0
4942	48500	2010	2001	0	-73.90	0	FALSE	0
4943	48500	2011	2001	8	8,154.41	0	FALSE	0
4944	48500	2005	2002	0	-450.60	0	FALSE	0
4945	48500	2006	2002	0	-2,673.30	0	FALSE	0
4946	48500	2007	2002	0	-1,165.50	0	FALSE	0
4947	48500	2008	2002	0	-2,465.80	0	FALSE	0
4948	48500	2009	2002	0	-87.70	0	FALSE	0
4949	48500	2010	2002	0	-74.20	0	FALSE	0
4950	48500	2011	2002	0	-41.60	0	FALSE	0
4951	48500	2011	2002	8	87,515.51	0	FALSE	0
4952	48500	2005	2003	0	-100.30	0	FALSE	0
4953	48500	2006	2003	0	-86.90	0	FALSE	0
4954	48500	2007	2003	0	-79.40	0	FALSE	0
4955	48500	2008	2003	0	-606.90	0	FALSE	0
4956	48500	2009	2003	0	-19.50	0	FALSE	0
4957	48500	2010	2003	0	-16.50	0	FALSE	0
4958	48500	2011	2003	0	-9.30	0	FALSE	0
4959	48500	2011	2003	8	23,582.40	0	FALSE	0
4960	48500	2006	2004	0	-4,820.40	0	FALSE	0
4961	48500	2007	2004	0	-17,635.70	0	FALSE	0
4962	48500	2008	2004	0	-3,215.50	0	FALSE	0
4963	48500	2009	2004	0	-874.90	0	FALSE	0
4964	48500	2010	2004	0	-744.30	0	FALSE	0
4965	48500	2011	2004	8	36,733.49	0	FALSE	0
4966	48500	2007	2005	0	-1,391.60	0	FALSE	0
4967	48500	2008	2005	0	-19,836.80	0	FALSE	0
4968	48500	2009	2005	0	-7,161.20	0	FALSE	0
4969	48500	2010	2005	0	-7,245.00	0	FALSE	0
4970	48500	2011	2005	0	-5,449.80	0	FALSE	0
4971	48500	2011	2005	8	17,543.91	0	FALSE	0
4972	48500	2011	2006	8	55,899.76	0	FALSE	0
4973	48500	2011	2007	8	48,284.13	0	FALSE	0
4974	48500	2011	2008	8	45,514.89	0	FALSE	0
4975	48500	2011	2009	8	37,388.92	0	FALSE	0
4976	48500	2011	2010	8	176,091.78	0	FALSE	0
4977	48500	2011	2011	8	66,923.57	0	FALSE	0
4978	48600	1987	1961	4	1,135.80	1961	FALSE	0
4979	48600	1992	1961	0	-1,135.80	0	FALSE	0
4980	48600	1992	1965	0	-609.00	0	FALSE	0
4981	48600	1992	1970	0	-200.00	0	FALSE	0

4982	48600	1992	1972	0	-13,230.00	0		FALSE	0
4983	48600	1992	1975	0	-50.20	0		FALSE	0
4984	48600	1992	1976	0	-405.00	0		FALSE	0
4985	48600	1992	1981	0	-4,370.20	0		FALSE	0
4986	48600	2011	1981	8	12,328.84	0		FALSE	0
4987	48600	2011	1982	8	997.00	0		FALSE	0
4988	48600	2011	1983	8	2,693.00	0		FALSE	0
4989	48600	2011	1985	8	7,145.00	0		FALSE	0
4990	48600	2011	1986	8	5,470.00	0		FALSE	0
4991	48600	2011	1987	8	654.46	0		FALSE	0
4992	48600	2011	1988	8	3,067.50	0		FALSE	0
4993	48600	2011	1989	8	6,505.50	0		FALSE	0
4994	48600	2011	1990	8	12,083.42	0		FALSE	0
4995	48600	2011	1991	8	5,466.50	0		FALSE	0
4996	48600	2011	1992	8	8,287.00	0		FALSE	0
4997	48600	2011	1993	8	4,525.80	0		FALSE	0
4998	48600	2011	1994	8	37,148.37	0		FALSE	0
4999	48600	2011	1995	8	8,886.16	0		FALSE	0
5000	48600	2011	1996	8	12,061.22	0		FALSE	0
5001	48600	2011	1997	8	32,424.05	0		FALSE	0
5002	48600	2011	1998	8	4,662.16	0		FALSE	0
5003	48600	2011	1999	8	179,948.08	0		FALSE	0
5004	48600	2000	2000	0	-28,109.80	0		FALSE	0
5005	48600	2000	2000	4	47,788.30	2000		FALSE	0
5006	48600	2011	2000	8	19,678.50	0		FALSE	0
5007	48600	2011	2001	8	11,510.86	0		FALSE	0
5008	48600	2011	2002	8	5,582.26	0		FALSE	0
5009	48600	2011	2003	8	649.95	0		FALSE	0
5010	48600	2011	2004	8	1,628.00	0		FALSE	0
5011	48600	2011	2005	8	9,903.90	0		FALSE	0
5012	48600	2011	2006	8	41,356.93	0		FALSE	0
5013	48600	2008	2007	3	-2,529.60	2007		FALSE	0
5014	48600	2011	2007	8	54,141.89	0		FALSE	0
5015	48600	2011	2008	8	59,380.00	0		FALSE	0
5016	48600	2011	2009	8	47,209.25	0		FALSE	0
5017	48600	2011	2010	8	228,077.07	0		FALSE	0
5018	48600	2011	2011	8	49,368.98	0		FALSE	0
5019	44500	2011	1981	0	-14,486.70	0	190961.0 adjustment to correct credit balance	FALSE	0
5020	44500	2011	1982	0	-176,474.30	0	190961.0 adjustment to correct credit balance	FALSE	0
5021	44500	2011	1982	8	0.00	0	190961.0 adjustment to correct credit balance	FALSE	0
5022	44500	2011	1970	0	-11,318.70	0	190961.0 adjustment to correct credit balance	FALSE	0
5023	44500	2011	1970	8	0.00	0	190961.0 adjustment to correct credit balance	FALSE	0
5024	44500	2011	1971	0	-127,371.00	0	190961.0 adjustment to correct credit balance	FALSE	0
5025	44500	2011	1971	0	-813.90	0	190961.0 adjustment to correct credit balance	FALSE	0
5026	44500	2011	1971	8	0.00	0	190961.0 adjustment to correct credit balance	FALSE	0
5027	48820	2011	1981	8	5,448.00	0		FALSE	0
5028	48820	2011	1983	8	3,328.00	0		FALSE	0
5029	48820	2011	1986	8	12,922.45	0		FALSE	0
5030	48820	2011	1988	8	27,878.53	0		FALSE	0
5031	48820	2011	1989	8	2,150.47	0		FALSE	0
5032	48820	2011	1993	8	9,630.81	0		FALSE	0
5033	48820	2011	1994	8	131,354.79	0		FALSE	0
5034	48820	2011	1995	8	1,870.05	0		FALSE	0

5035	48820	2011	1996	8	12,740.02	0		FALSE	0
5036	48820	2011	1997	8	17,391.56	0		FALSE	0
5037	48820	2011	1999	8	46,813.85	0		FALSE	0
5038	48820	2011	2000	8	8,693.67	0		FALSE	0
5039	48820	2011	2003	8	3,969.00	0		FALSE	0
5040	48820	2011	2005	8	21,131.34	0		FALSE	0
5041	48820	2011	2006	8	50,584.94	0		FALSE	0
5042	48820	2011	2007	8	51,201.54	0		FALSE	0
5043	48820	2009	2008	4	1,821.25	2008		FALSE	0
5044	48820	2011	2008	8	56,889.23	0		FALSE	0
5045	48820	2011	2009	8	1,543.92	0		FALSE	0
5046	48820	2011	2010	8	7,346.76	0		FALSE	0
5047	48820	2011	2011	8	367.33	0		FALSE	0
5048	49100	2011	2004	8	1,493.00	0		FALSE	0
5049	49602	2009	2008	4	20,358.53	2008		FALSE	0
5050	49602	2011	2008	8	1,534,576.40	0		FALSE	0
5051	49605	2011	2004	8	39,054.57	0		FALSE	0
5052	49605	2011	2005	8	196,443.00	0		FALSE	0
5053	49605	2010	2009	4	102,849.81	2009		FALSE	0
5054	49628	2011	2009	8	357,819.74	0		FALSE	0
5055	49100	2011	2004	8	-1,493.00	0	Per YECL	TRUE	0
5056	49602	2009	2008	4	-20,358.53	2008	Per YECL	TRUE	0
5057	49602	2011	2008	8	-1,534,576.40	0	Per YECL	TRUE	0
5058	49605	2011	2004	8	-39,054.57	0	Per YECL	TRUE	0
5059	49605	2011	2005	8	-196,443.00	0	Per YECL	TRUE	0
5060	49605	2010	2009	4	-102,849.81	2009	Per YECL	TRUE	0
5061	49628	2011	2009	8	-357,819.74	0	Per YECL	TRUE	0
5062	48300	2011	1988	8	-834.92	0		TRUE	0
5063	48300	2011	1989	8	-2,150.48	0		TRUE	0
5064	48300	2011	1990	8	-1,503.14	0		TRUE	0
5065	48300	2011	1991	8	-2,966.04	0		TRUE	0
5066	48300	2011	1992	8	-909.82	0		TRUE	0
5067	48300	2011	1993	8	-378.67	0		TRUE	0
5068	48320	2011	2004	8	-74.62	0		TRUE	0
5069	48500	2011	1991	8	-3,238.21	0		TRUE	0
5070	48500	2011	1992	8	-156.97	0		TRUE	0
5071	48500	2011	1993	8	-1,288.17	0		TRUE	0
5072	48500	2011	1994	8	-3,064.70	0		TRUE	0
5073	48500	2011	1995	8	-1,070.05	0		TRUE	0
5074	48600	2011	1981	8	-12,328.84	0		TRUE	0
5075	48600	2011	1982	8	-997.00	0		TRUE	0
5076	48600	2011	1983	8	-2,693.00	0		TRUE	0
5077	48600	2011	1985	8	-7,145.00	0		TRUE	0
5078	48600	2011	1986	8	-5,470.00	0		TRUE	0
5079	48600	2011	1987	8	-654.46	0		TRUE	0
5080	48600	2011	1988	8	-3,067.50	0		TRUE	0
5081	48600	2011	1989	8	-6,505.50	0		TRUE	0
5082	48600	2011	1990	8	-12,083.42	0		TRUE	0
5083	48600	2011	1991	8	-5,466.50	0		TRUE	0
5084	48600	2011	1992	8	-8,287.00	0		TRUE	0
5085	48600	2011	1993	8	-4,525.80	0		TRUE	0
5086	48600	2011	1994	8	-37,148.37	0		TRUE	0
5087	48600	2011	1995	8	-8,886.16	0		TRUE	0

COMPANY 05
WORK ORDER HEADER REPORT
As of September 15, 2004

GENERAL INFORMATION

WORK ORDER NUMBER	Y10637
DESCRIPTION	YECL Carcross Line Rebuild
PROJECT NUMBER	70004
FILE NUMBER	NA
REPONSIBILITY	
DIVISION	YUKON
DISTRICT	Whitehorse South
LOCATION	Klondike Hwy 2, from KM 120 to 132.5
PROPERTY NUMBER	YT0071
LEGAL DESCRIPTION	
STATUS CODE	A
BUDGET AMOUNT	

METERING SERVICES

METERING TYPE	
CT RATING	
PT RATING	
FARM BREAKER SIZE	
NUMBER	
PHASES	
WIRES	
SECONDARY VOLTS	
LOAD - KVA	
NEW KM OF LINE	
SALVAGED KMS OF LINE	
GROUND TEST OHMS	
CONDUCTOR SIZE	
LARGEST MOTOR HP	

CUSTOMER INFORMATION

CUSTOMER NAME	
CUSTOMER ACCOUNT	
BILLING NAME	
BILLING ADDRESS	
TOWN/CITY	
PROVINCE	
POSTAL CODE	
TELEPHONE NUMBER	
CUSTOMER CONTRIBUTION AMOUNT	
SIC CODE	
RATE CODE	
RATE SCHEDULE	
CONTRACT MIN	

WORK ORDER REMARK

COSTS TO INSTALL TWENTY ONE 40'CL5 POLES, FIVE 40' CL3 POLES, TEN 45'CL5 POLES, THREE 45'CL3 POLES, THREE 50'CL3 POLES, THIRTEEN ANC-T, FOUR ANC-E, STRINGING OF APPROX. 3600 METERS OF 4x#1/0 ACSR AND SALVAGE OF 34 POLES, FIVE ANCHORS.

ESTIMATED COSTS

WBS CATEGORIES
- BRUSHING
- COMMISSIONING
- CONSTRUCTION
- CUSTOMER SERVICE
- DESIGN
- DRAFTING
- L.T. & E. NOT IN USE
- LAND ACQUISITION
- MATERIAL COSTS NOT IN USE
- OVERHEAD CHARGES
- PROJECT MANAGEMENT
- SALVAGE MATERIAL
- SALVAGE
- SURVEY
- UNCODED CHARGES

WIP TOTAL:

TRANSFORMERS INSTALLED > 25 KVA	0	TARGET HOURS	0
TRANSFORMERS REMOVED > 25 KVA	0	SAFETY	0
SERVICES	0	TRAVEL	0
METERING	$0	CONSTRUCTION	0
SUBSTATION ASSESSMENT	0	SALVAGE	
REGULATORS	0	TOTAL	0 *
		ACTUTAL HOURS	0 *

TOTAL ESTIMATE **

RELEASES, APPROVALS, DATE

CUSTOMER DATE		
DATE WORK ORDER RAISED		
FIELD CHECK RECEIVED		
EASEMENT/BRUSHING REQUESTED		
EASEMENT/BRUSHING RECEIVED		
EXTERNAL APPROVAL RECEIVED		
FINAL W.O. REALEASE DATE		
DATE WORK STARTED		
IN-SERVICE DATE (EST)		
CUSTOMER ACCEPTANCE DATE		
WO IN FOR CLOSE		SIGNATURE
ENGINEERING APPROVAL	P. BORGEL	Mar 27/08
MARKETING APPROVAL		Mar 27/08
EXPENDITURE APPROVAL	LUKE HORRELT	
SUBMITTED BY	YESH SHARMA	03-26-2008
DRAFTED BY		
CONST COMPLETE BY		
CLOSE OUT APPROVAL		APR.28/08

ATCO Electric

LINE COMMISSIONING REPORT

DISTRICT	LINE NUMBER	CONTRACTOR	W.O. NUMBER
		ARCTIC POWER	Y10637

TYPE OF LINE OVERHEAD 34.5 KV

DESCRIPTION AS PER AS BUILT.

Brushing completed to company standards.	☑ YES	☐ NO	Brushing Standard SC34-1
Line construction complete.	☐ YES	☑ NO	If NO, complete deficiencies section below
Completed to company standards.	☑ YES	☐ NO	If NO, complete deficiencies section below
Were any design changes made?	☐ YES	☑ NO	If YES, attach changes to as-built
Design changes approved.	☐ YES	☑ N/A	Changes indicated in red on design drawing
Construction inspection report completed.	☐ YES	☑ NO	
All other reports completed:			
S.I.R.	☐ YES	☑ N/A	
EQUIP. REP. #	☐ YES	☑ N/A	
AS BUILT (stamped)	☐ YES	☑ NO	
All tags installed.	☑ YES	☐ NO	If NO, complete deficiencies section below
Ground/ Road / RR/ PL clearance measured.	☑ YES	☐ N/A	Distance measured: 1_____ 2_____ 3_____ 4_____
Left energized.	☐ YES	☐ NO	If YES, approved by _____

DEFICIENCIES CONSTRUCTION LOOKS GOOD, NOT TIED IN OR COMPLETLY SAGGED AT THIS POINT. WHAT IS SAGGED LOOKS GOOD.

CONSTRUCTION START	Date	Crew Foreman
RELEASE TO ENERGIZE	Date	Crew Foreman
ACCEPTED BY	Date	Construction Lead
APPROVED BY	Date April 16, 2008	O.I.C. Darcy Rusnak
ACCEPTED BY	Date 08/04/15 June 5/08	O&M Representative A. INGRAM.

SERVICE CONNECTION

Customer _____ Date of hookup _____

Electrical permit received	☐ YES	☐ NO
Meter forms complete	☐ YES	☐ NO

ATCO Electric

CONSTRUCTION INSPECTION REPORT

DATE: 08/05/20
WORK ORDER #: 410637
CONTRACTOR: ARCTIC POWER
LOCATION/LSD: CYPRESS LINE

	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
A: Poles:				
1. Tamping & Backfill				
2. Straightness of Line				
3. Tagged – ATCO				
4. Setting Depth				
B: FRAMING:				
1. As per staking/drawing				
2. Bonding as per manual				
C: ANCHORING:				
1. Pole rake/kick				
2. As per staking/drawing				
3. Bonding bolts				
4. Bonding between guy downhauls				
5. Guy Guards installed				
6. Tight Guy				
D: STRINGING/SAG:				
1. Line Sag				
2. Ties as per staking/drawing				
3. Ground Clearance				spot check for suspicious spans
4. Road/RR/Pipeline Clearance				
E: GROUNDING:				
1. Ground as per staking/drawing				
2. All ground connections completed				
3. Meggered & Tagged				
4. High Voltage sign installed				
F: SWITCHES:				
1. Fuse size tag installed				Fuse Size: Amps:
2. Switch number installed				
G: TRANSFORMER:				
1. All connections complete/correct				
2. All ground connections completed				
3. Oil leaks/bushings				
4. Voltage				
H: SERVICE CONNECTIONS:				
1. All connections completed				
2. Grounding is complete/correct				
3. Cabinet & Breaker connections				

ATCO Electric

I: BRUSHING:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Clearance adequate				
2. Clean up ok				

J: URGD XMER/RISER POLE:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Phase tags installed				
2. Danger High Voltage signs installed				
3. Danger Buried Cable signs installed				
4. Warning signs installed				
5. All connections completed				
6. Service address tags installed				
7. Locks installed				
8. Trench settled				

K: SALVAGE WORK:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. All material picked up				OLD PORTION
2. All wire rolled up				NEEDS TO BE
3. All holes filled in				SALVAGED
4. All anchors pulled				
5. Site left presentable				

L: DAMAGE:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Ruts				
2. Other				

M: ADDITIONAL WORK TO BE DONE (DEFFIENCIES)

ACTION PLAN	WHO	WHEN

DEFICIENCIES COMPLETED: _____

REPORT COMPLETED BY: A. INGRAM DATE: 08/05/20

REPORT ACCEPTED BY: Darcy Rusnak DATE: April 16, 2008

REQ# 46422
20810
To warehouse Sept 28

Const Start Nov ???

ATCO Electric

September 27, 2007 10:35 AM

Matest Information ut

Project No.: Y10637
Project Description: Carcross Line rebuild 2007 Km. 129.3 to 132.7
Klondike Hwy.

Revision: Sept. 27, 2007
Us J. Michael
er

☐ Standard Cost Estimate

Segment Name	Qty	Structure	#of Cond.	Comments
	0	#2:0	3	
	29	X0A		
	1	R154		
	1	R171		
	4	ANC-T		
	6	X0B		
	4	G40		
	7	G10		
	7	ANC-E		
	10	E12A		
	2	R0		
	2	Y52		
	2	Y54		
	6	Y12B		

Issued Oct 29/07 KD

ORDER PICKED
OCT 29/07
MMS

INITIALS NB

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE	
4		E190054	8311	BOLT EYE 5/8X 8 IN GALV				B1A004
3		E190055	8311	BOLT EYE 5/8X10 IN GALV				B1A005
1		E190056	8311	BOLT EYE 5/8X12 IN GALV				B1A006
1		E190073	8311	BOLT LAG 1/2X04 1/2 IN GALV				B1B003
24		E190079	8311	BOLT MACH 1/2X07 IN GALV				B1B006
2		E190067	8311	BOLT EYE SHOULDER 3/4X18 GALV				B1B011
2		E190069	8311	BOLT EYE SHOULDER 3/4X22 GALV				B1B013
1		E190094	8311	BOLT MACH 5/8X10 IN GALV				B1C007
29		E190095	8311	BOLT MACH 5/8X12 IN GALV				B1C008
29		E190096	8311	BOLT MACH 5/8X14 IN GALV				B1C009
4		E190108	8311	BOLT MACH 3/4X12 IN GALV				B1D004
6		E190110	8311	BOLT MACH 3/4X16 IN GALV				B1D006
1		E360066	8311	BRKT SWCH MTG ATCO SPEC #10984				B1E003
2		E190143	8311	CLAMP BAIL 6 TO 1/0				B1E004
6		E190144	8311	CLAMP BAIL 1/0 TO 556				B1E005
11		E190137	8311	CLAMP BOND POWER/ANC				B1E006
8		E190168	8311	CLAMP HL SCREW TYPE				B1E008
22	+3	E190484	8311	CLEVIS FOR PREF DEADEND GRIP				B1E009
6		E190495	8311	CLEVIS SPOOL TYPE DEAD END				B1E010
10		E190187	8311	CNTR GRD ROD 3/4 IN ROD				B1E012
10		E190201	8311	COUPLING GRD/ROD SPEC 9941				B1E014
11		E190530	8311	FITTING GUY				B1E015
35		E260220	8311	INSUL SPOOL SL355				B2A005
1		E260235	8311	INSUL DE 25 KV POLYMERIC				B2A007
18		E260236	8311	INSUL DE 35 KV POLYMERIC				B2A008
4		E210047	8311	SHELL AMPACT BLUE 69338-1				B2A009
4	B.O.	E190245	8311	CNTR AMP BLUE 600411				B2A013
8		E190590	8311	PIN PLTP SL3049				B2A015
10		E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD				B2B002
14		E190620	8311	GRIP DE PREF 5/16 GUY WIRE				B2B003
29		E190716	8311	WASHER RD GALV FOR 5/8" BOLT				B2C007
16		E190601	8311	GRIP DE PREF 2/0 ACSR				B2D004
24		E190471	8311	NUT PAL 1/2 INCH GALV				B2D005
71		E190472	8311	NUT PAL 5/8 INCH GALV				B2D006
81		E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8				B2D007

26		E190473	8311	NUT PAL 3/4 INCH GALV				B2D008
26		E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4				B2D009
24		E190715	8311	WASHER RD GALV FOR 1/2" BOLT				B2E004
89		E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE				B2E005
30		E190730	8311	WASHER SQ 3X3X13/16 HOLE				B2E006
24		E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT				B2E011
18		E190586	8311	PIN XARM SL 5728				B3A017
~~0~~		~~E300909~~	~~8311~~	~~SLEEVE AUTO 2/0 ACSR 6/1~~				B3C017
50		E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED				B3C022
1		E190548	8311	STRAP BONDING 9" T-STD-807 A				B3D006
8		E190508	8311	GAIN POLE GALV 3/4" BOLT				B3D008
10		E190466	8311	NUT EYE 5/8 IN GALV				B3D009
2		E190467	8311	NUT EYE 3/4 IN GALV				B3D010
7		E190480	8311	NUT EYE 3/4" OR 1" ANC ROD ALL				B3D011
4		E190030	8311	BOLT DA 5/8X24 IN GALV				B3E021
1		E260306	8311	SWCH DISC 25KV 100A				QT0000
10		E160078	8311	COND ROUND 3/4 IN PVC				RA0001
11		E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH				RA0001
11		E260255	8311	INSUL GUY STRAIN				RA0001
4		E190677	8311	ROD ANC 1 X 10 GALV				RA0001
7		E190679	8311	ROD ANC PWR 3/4 X 7FT				RA0001
20		E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941				RA0001
65	+20	E350017	8311	WIRE ALUM*TIE 4				RB0002
150		E350078	8311	WIRE CU 2 STRD WP				RB0002
2		E350077	8311	WIRE CU 4 STRD WP				RB0002
24		E190631	8311	ROD ARM ACSR 2/0 61IN				RB0004
8		E190626	8311	GRIP DE PREF 7/16 GUY WIRE				RC0002
7		E190013	8311	ANC PWR S/HELIX 10IN TOUGH ONE				RD0001
26		E260216	8311	INSUL CP 4575				RF0001
4		E190000	8311	ANCHOR XPLATE 24 IN				YA0001
12		E360031	8311	BRACE V ANG ARM 60 IN				YA0001
84		E350029	8311	WIRE GUY 5/16 GRADE 180 COILS				YA0001
60		E350031	8311	WIRE GUY 7/16 GRADE 180 COILS				YA0002
~~0~~		~~E350002~~	~~8311~~	~~WIRE ACSR 2/0 6/1 QUAIL~~				YA0003
12		E360018	8311	ARM 2P 5 X6X 8 FT GLU-LAM				YB0001
~~29~~		~~999976~~	8311	SPOOL TIE				#N/A
150		E190897	8311	STAPLE FENCE				#N/A
~~6~~		~~999999~~	8311	TIE DISTRIBUTION FOR 34 KV				#N/A
4		E190~~699~~	8311	WASHER CURVED 3 IN 13/16 H				#N/A
		700						

PICKED
OCT 29/04
AMS
INITIALS

ATCO Electric

Issued aug 9/06 KD

July 12, 2006 4:20 PM

Matest Programitput

Project No.: Y10637 - preliminary list
Project Description: 34kv rebuild km 129 - 131 hwy 2

Revision: preliminary
User: phil

☐ Standard Cost Estimate

Segment Name	Qty	Structure	#of Cond.	Comments
	3.4	#1:0	4	
	40	Y12		
	4	Y52		
	37	P40-5		
	7	P40-3		
	4	G40		
	4	ANC-T		

21133
9290

Parts List

QTY	MMS CAT#	OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE	TOTAL PRICE	
96	02-03-5107	E190079	8311	BOLT MACH 1/2X07 IN GALV	0.69	65.93	B1B006
4	02-03-2222	E190069	8311	BOLT EYE SHOULDER 3/4X22 GALV	3.63	14.52	B1B013
84	02-03-5312	E190095	8311	BOLT MACH 5/8X12 IN GALV	1.10	92.18	B1C008
4	02-03-5512	E190108	8311	BOLT MACH 3/4X12 IN GALV	1.75	7.02	B1D004
40	02-03-5516	E190110	8311	BOLT MACH 3/4X16 IN GALV	1.84	73.42	B1D006
24	02-07-2475	E190484	8311	CLEVIS FOR PREF DEADEND GRIP	2.61	62.53	B1E009
4	02-11-1110	E190530	8311	FITTING GUY	3.14	12.58	B1E015
24	10-05-3145	E260236	8311	INSUL DE 35 KV POLYMERIC	29.03	696.73	B2A008
44	02-07-5525	E190590	8311	PIN PLTP SL3049	0.78	34.32	B2A015
24	08-09-1730	E190600	8311	GRIP DE PREF 1/0 ACSR	1.41	33.79	B2D003
96	02-05-1522	E190471	8311	NUT PAL 1/2 INCH GALV	0.13	12.53	B2D005
92	02-05-1542	E190472	8311	NUT PAL 5/8 INCH GALV	0.18	16.54	B2D006
112	02-05-6392	E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8	0.17	19.55	B2D007
128	02-05-1562	E190473	8311	NUT PAL 3/4 INCH GALV	0.17	21.41	B2D008
128	02-05-6394	E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4	0.22	28.60	B2D009
96	02-05-6228	E190715	8311	WASHER RD GALV FOR 1/2" BOLT	0.08	7.64	B2E004
116	02-05-6425	E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE	0.27	31.81	B2E005
132	02-05-6435	E190730	8311	WASHER SQ 3X3X13/16 HOLE	0.85	112.09	B2E006
96	02-05-6148	E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT	0.05	4.78	B2E011
88	02-07-5415	E190586	8311	PIN XARM SL 5728 B.O.	17.52	1,542.08	B3A017
8	08-03-1034	E300008	8311	SLEEVE AUTO 1/0 ACSR 6/1	8.02	64.19	B3C016
40	02-07-3435	E190508	8311	GAIN POLE GALV 3/4" BOLT	4.16	166.32	B3D008
20	02-05-1025	E190466	8311	NUT EYE 5/8 IN GALV	1.44	28.78	B3D009
4	02-05-1040	E190467	8311	NUT EYE 3/4 IN GALV	1.40	5.61	B3D010
8	02-03-0424	E190030	8311	BOLT DA 5/8X24 IN GALV	2.34	18.75	B3E021
4	02-11-1247	E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH	3.14	12.57	RA0001
4	10-09-1510	E260255	8311	INSUL GUY STRAIN	23.08	92.33	RA0001
4	02-11-3342	E190677	8311	ROD ANC 1 X 10 GALV	25.59	102.35	RA0001
8	08-09-2310	E190626	8311	GRIP DE PREF 7/16 GUY WIRE	3.64	29.13	RC0002
132	10-03-2245	E260216	8311	INSUL CP 4575	25.89	3,416.84	RF0001
4	02-11-0224	E190000	8311	ANCHOR XPLATE 24 IN	29.96	119.85	YA0001
48	02-07-0444	E360031	8311	BRACE V ANG ARM 60 IN	19.51	936.66	YA0001
60	06-07-0330	E350031	8311	WIRE GUY 7/16 GRADE 180 COILS	1.09	65.27	YA0002
13804	06-03-1231	E350001	8311	WIRE ACSR 1/0 6/1 RAVEN 15818	0.65	9,026.99	YA0003
37	04-03-4540	E360117	8311	POLE 40 FT CLASS 5	207.74	7,686.33	YA0018
7	04-03-0150	E360075	8311	POLE 40 FT CLASS 3	288.82	2,021.71	YA0019
48	04-05-2114	E360018	8311	ARM 2P 5 X6X 8 FT GLU-LAM	72.85	3,496.62	YB0001
44	38-07-0026	E290041	8311	TAG ASSET STRUCTURE ID ALUM.	1.17	51.48	#N/A
132		999999	8311	TIE DISTRIBUTION FOR 34 KV	0.00	0.00	#N/A
							#N/A

Total Unloaded Stocked Material Cost $30,232
Spot Construction Manhours 256.52

Cancelled Oct 30/07 (see new req)

ATCO Electric

To warehouse Oct 30

October 30, 2007 1:17 PM

Matest Informationut

Project No.: Y10637
Project Description: YECL Carcross 34 kv line rebuild

Revision:
Us
er:

☐ Standard Cost Estimate

Segment Name	Qty	Structure	#of Cond.	Comments
	0	#1:0	1	
	3	E12A		
	4	R0		
	1	X0A		
	1	G10		
	3	P40-3		
	1	P45-3		
	6	P45-5		
	19	P40-5		
	1	Y14		

Issued
Nov 13/07
K.D.

Req # 48848
S.O. # 21996

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE	
4		E190055	8311	BOLT EYE 5/8X10 IN GALV				B1A005
1		E190079	8311	BOLT MACH 1/2X07 IN GALV				B1B006
2		E190095	8311	BOLT MACH 5/8X12 IN GALV				B1C008
1		E190096	8311	BOLT MACH 5/8X14 IN GALV				B1C009
1		E190110	8311	BOLT MACH 3/4X16 IN GALV				B1D006
4		E190484	8311	CLEVIS FOR PREF DEADEND GRIP				B1E009
3		E190187	8311	CNTR GRD ROD 3/4 IN ROD				B1E012
3		E190201	8311	COUPLING GRD/ROD SPEC 9941				B1E014
1		E190530	8311	FITTING GUY				B1E015
1		E260220	8311	INSUL SPOOL SL355				B2A005
3		E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD				B2B002
2		E190620	8311	GRIP DE PREF 5/16 GUY WIRE				B2B003
1		E190716	8311	WASHER RD GALV FOR 5/8" BOLT				B2C007
4		E190600	8311	GRIP DE PREF 1/0 ACSR				B2D003
1		E190471	8311	NUT PAL 1/2 INCH GALV				B2D005
8		E190472	8311	NUT PAL 5/8 INCH GALV				B2D006
7		E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8				B2D007
1		E190473	8311	NUT PAL 3/4 INCH GALV				B2D008
2		E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4				B2D009
1		E190715	8311	WASHER RD GALV FOR 1/2" BOLT				B2E004
9		E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE				B2E005
1		E190670	8311	TIE SPOOL FOR 1/0 ACSR RAVEN				B2E010
1		E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT				B2E011
~~0~~		~~E300008~~	~~8311~~	SLEEVE AUTO 1/0 ACSR 6/1				B3C016
15		E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED				B3C022
8		E300074	8311	SLEEVE SQUEEZON BB WR279				B6A020
3		E160078	8311	COND ROUND 3/4 IN PVC				RA0001
1		E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH				RA0001
1		E260255	8311	INSUL GUY STRAIN				RA0001
6		E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941				RA0001
1		E350017	8311	WIRE ALUM*TIE 4				RB0002
45	#2	E350078	8311	WIRE CU 2 STRD WP				RB0002
3		E260216	8311	INSUL CP 4575				RF0001
3		E190594	8311	PIN ANGLE 34KV C/W 13/8 THREAD				RF0002
1		E360033	8311	BRACE ANG OFFSET 60 IN				YA0001
12		E350029	8311	WIRE GUY 5/16 GRADE 180 COILS				YA0001
~~0~~		~~E350001~~	8311	WIRE ACSR 1/0 6/1 RAVEN				YA0003
19		E360117	8311	POLE 40 FT CLASS 5				YA0018
6		E360118	8311	POLE 45 FT CLASS 5				YA0018

3		E360075	8311	POLE 40 FT CLASS 3				YA0019
1		E360080	8311	POLE 45 FT CLASS 3				YA0019
1		E360018	8311	ARM 2P 5 X6X 8 FT GLU-LAM				YB0001
45		~~999999~~	8311	STAPLE FENCE				#N/A
3		999999	8311	TIE DISTRIBUTION FOR 34 KV				

E/190897

ATCO Electric

March 26, 2008 8:25 AM

Click for Program Properties

Project No.: Y10637
Project Description: YECL 34 KV Carcross Line Rebuild additional material

Revision:
User: Y Sharma

Segment Name	Qty	Structure	#of Cond.	Comments
	0	#1:0	1	
	1	Y12		
	2	Y31		
	2	R0		
	1	X0A		
	4	ANC-T		
	6	G40		
	3	E12A		
	2	P45-3		

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE		
8		E190054	8311	BOLT EYE 5/8X 8 IN GALV			0.00		B1A004
2		E190055	8311	BOLT EYE 5/8X10 IN GALV			0.00		B1A005
18		E190079	8311	BOLT MACH 1/2X07 IN GALV			0.00		B1B006
4		E190067	8311	BOLT EYE SHOULDER 3/4X18 GALV			0.00		B1B011
6		E190095	8311	BOLT MACH 5/8X12 IN GALV			0.00		B1C008
1		E190096	8311	BOLT MACH 5/8X14 IN GALV			0.00		B1C009
6		E190108	8311	BOLT MACH 3/4X12 IN GALV			0.00		B1D004
1		E190110	8311	BOLT MACH 3/4X16 IN GALV			0.00		B1D006
6		E190144	8311	CLAMP BAIL 1/0 TO 556			0.00		B1E005
6		E190137	8311	CLAMP BOND POWER/ANC			0.00		B1E006
14		E190484	8311	CLEVIS FOR PREF DEADEND GRIP			0.00		B1E009
3		E190187	8311	CNTR GRD ROD 3/4 IN ROD			0.00		B1E012
3		E190201	8311	COUPLING GRD/ROD SPEC 9941			0.00		B1E014
6		E190530	8311	FITTING GUY			0.00		B1E015
1		E260220	8311	INSUL SPOOL SL355			0.00		B2A005
12		E260236	8311	INSUL DE 35 KV POLYMERIC			0.00		B2A008
1		E190590	8311	PIN PLTP SL3049			0.00		B2A015
3		E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD			0.00		B2B002
1		E190716	8311	WASHER RD GALV FOR 5/8" BOLT			0.00		B2C007
14		E190600	8311	GRIP DE PREF 1/0 ACSR			0.00		B2D003
18		E190471	8311	NUT PAL 1/2 INCH GALV			0.00		B2D005
17		E190472	8311	NUT PAL 5/8 INCH GALV			0.00		B2D006
17		E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8			0.00		B2D007
13		E190473	8311	NUT PAL 3/4 INCH GALV			0.00		B2D008
13		E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4			0.00		B2D009
18		E190715	8311	WASHER RD GALV FOR 1/2" BOLT			0.00		B2E004
21		E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE			0.00		B2E005
17		E190730	8311	WASHER SQ 3X3X13/16 HOLE			0.00		B2E006
1		E190670	8311	TIE SPOOL FOR 1/0 ACSR RAVEN			0.00		B2E010
18		E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT			0.00		B2E011
4		E190586	8311	PIN XARM SL 5728			0.00		B3A017
0		E300008	8311	SLEEVE AUTO 1/0 ACSR 6/1			0.00		B3C016
15		E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED			0.00		B3C022
3		E190508	8311	GAIN POLE GALV 3/4" BOLT			0.00		B3D008
4		E300074	8311	SLEEVE SQUEEZON BB WR279			0.00		B6A020
3		E160078	8311	COND ROUND 3/4 IN PVC			0.00		RA0001
6		E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH			0.00		RA0001
6		E260255	8311	INSUL GUY STRAIN			0.00		RA0001
4		E190677	8311	ROD ANC 1 X 10 GALV			0.00		RA0001

6		E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941			0.00		RA0001
1		E350017	8311	WIRE ALUM*TIE 4			0.00		RB0002
45		E350078	8311	WIRE CU 2 STRD WP			0.00		RB0002
12		E190626	8311	GRIP DE PREF 7/16 GUY WIRE			0.00		RC0002
5		E260216	8311	INSUL CP 4575			0.00		RF0001
4		E190000	8311	ANCHOR XPLATE 24 IN			0.00		YA0001
9		E360031	8311	BRACE V ANG ARM 60 IN			0.00		YA0001
90		E350031	8311	WIRE GUY 7/16 GRADE 180 COILS			0.00		YA0002
0		E350001	8311	WIRE ACSR 1/0 6/1 RAVEN			0.00		YA0003
2		E360080	8311	POLE 45 FT CLASS 3			0.00		YA0019
5		E360018	8311	ARM 2P 5 X6X 8 FT GLU-LAM			0.00		YB0001
45		E190897	8311	FENCE STAPLES, HOT DIP GALVANIZED 1 3/4"			0.00		#N/A
5		999999	8311	TIE DISTRIBUTION FOR 34 KV			0.00		#N/A
6		E190698	8311	WASHER CURVED 3 IN 13/16 H			0.00		#N/A
2		E360118	8311	POLE 45' CLS					#N/A

Total Unloaded Stocked Material Cost	$0
Spot Construction Manhours	
Total Loaded Stocked Mat Cost(9%)	$0

THE YUKON ELECTRICAL COMPANY LIMITED
An *ATCO* Company

STAKING LIST

Revised: September 19/2007 DS

Project Number: Y10637 Carcross Line Rebuild 2007
Location: Km 129.3 to Km 132.7 Klondike Hwy
Survey Date: July 21/2007 by D. Sturko
Page: 1 of 3

						Medium Loading Design	
YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
S6708	exist gangsw	50		40ft	cl.4 1993	exist: 34.5Kv Gangswitch **no changes**	existing conductor 3 x 2/0 ACSR
21507	1	70		40ft	cl.3	Y41, Y54, (2)G40, anc-T same guy config as G24	slack span xarm below **outage required**
Exist "A"				35	5	Exist: Y12, R154 ADD: E12A,Anc-T, G40 (10 m anchor)	**Add: temp anchor and ground to DE the exist 34 KV primary**
21507	1	12		40ft	cl.3	AS ABOVE	
21508	2	81.2		40ft	cl.3	Y52, Y54, R0, E12A, (2)G40, anc-T do not install 3 dead end insulators same guy config as G24	slack span xarm below set up for future off back of xarm use 7/16" guy steel
21509	3	82.7		45ft	cl.3	Y12, X0-A, R154,R171,G10,anc-T	SW# S8723 fuse: 3A
21510	4	83.7		40ft	cl.5	Y12, X0-A	
21511	5	78.5		40ft	cl.5	Y12, X0-A, E12A	
21512	6	85		45ft	cl.5	Y12, X0-A,	
21513	7	85.1		40ft	cl.5	Y12. X0-A	
21514	8	84.9		40ft	cl.5	Y12, X0-A	
21515	9	72.6		40ft	cl.5	Y12, X0-A, E12A	
21516	10	84.7		40ft	cl.5	Y12, X0-A,	
21517	11	84.9	<LT	50ft	cl.3	Y12B, X0-B, G10, anc-E	9°32'54"<LT
21518	12	74.8	<LT	45ft	cl.5	Y12B, X0-B, G10, anc-E	7°57'00"<LT
21519	13	75.3	<LT	40ft	cl.5	Y14, X0-B, E12A, G10, anc-E	12°35'28"<LT
21520	14	79.5	<LT	40ft	cl.5	Y12B, X0-B, G10, anc-E	7°42'34"<LT
21521	15	84.8		40ft	cl.3	Y52, (2)R0, (2)G40, anc-T same guy config as G24	**temp. stringing point** use 7/16" guy steel
21522	16			40ft	cl.5	Y12, X0-A, E12A	

THE YUKON ELECTRICAL COMPANY LIMITED
An *ATCO* Company

STAKING LIST

Revised: September 19/2007 DS

Project Number: Y10637 Carcross Line Rebuild 2007
Location: Km 129.3 to Km 132.7 Klondike Hwy
Survey Date: July 21/2007 by D. Sturko
Page: 2 of 3

Medium Loading Design

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
21522	16			40ft	cl.5	AS ABOVE	
		84.6					
21523	17			50ft	cl.3	Y12, X0-A	
		85.1					
21524	18			45ft	cl.5	Y12, X0-A,	may be rocky
		66.9					
21525	19			45ft	cl.5	Y12, X0-A	may be rocky
		84.9					
21526	20			45ft	cl.5	Y12, X0-A, E12A	
		84.4					
21527	21			40ft	cl.5	Y12, X0-A	
		84.4					
21528	22			40ft	cl.5	Y12, X0-A,	
		84.8					
21529	23			45ft	cl.5	Y12, X0-A,	
		84.9					
21530	24			40ft	cl.5	Y12, X0-A, E12A	
		85.2					
21531	25			45ft	cl.5	Y12, X0-A	
		82.2					
21532	26			40ft	cl.5	Y12, X0-A,	
		78.6					
21533	27			40ft	cl.3	Y52, (2)R0, (2)G40, anc-T same guy config as G24	**temp. stringing point** use 7/16" guy steel
		77.7					
21534	28		<RT	40ft	cl.5	Y12B, X0-B, E12A, G10,anc-T	may be rocky 3°27'14"<RT
		77.8					
21535	29		<RT	40ft	cl.5	Y12B, X0-B, G10,anc-T	may be rocky 9°31'34"<RT
		80.3					
21536	30		<RT	40ft	cl.5	Y12B, X0-B, G10,anc-T	may be rocky 6°31'54"<RT
		84.8					
21537	31			40ft	cl.5	Y12, X0-A	
		85.1					
21538	32			50ft	cl.3	Y12, X0-A, E12A	

DISTRIBUTION DEPARTMENT
PROJECT HEADER REPORT

AL INFORMATION

PROJECT NUMBER	Y11637
PROJECT NAME	DDC power Line upgrade to 3 ph and Health Centre
PROJECT DESCRIPTION	Line upgrade from 1 ph to 3 ph from Luckey Lk to Lower Post Health Centre
APPROPRIATION	70001
ASSET PLANT	YT0077
PROJECT STATUS	Active
REGION	Destruction Bay
DISTRICT	
SERVICE POINT	
PROJECT LEAD	Yesh Sharma
PROJECT REQUESTED BY	Customer
CU IER CONTACT	Mark Thorvaldson
CU CONTACT PHONE	250 779 3161

ERING AND SERVICES

NUMBER OF SERVICES	1
METERING STANDARD	one 3 phase at 120/208V
METERING TYPE	CT metering
CT RATING	NA
PT RATING	NA
FARM BREAKER SIZE	NA
PHASES	3
SECONDARY VOLTS	120/208V
CUST. OPER. KVA	3X50KVA
RATE CLASS CODE	
TOTAL TRANSFORMER KVA	

IMATED BURDENED COSTS

EASEMENTS	NA
SURVEY	NA
BRUSHING	NA
MATERIAL	Ken Oppoled
MATERIAL HANDLING	
C RUCTION LT&E	
PR CT LT&E	
MISCELLANEOUS CHARGES	
DEMOLITION & SALVAGE	Exist 1 ph line to salvage
CAPITAL ADJUSTMENTS	
TOTAL PROJECT ESTIMATE:	

IER COSTS (for info only)

SYSTEM COST CONTRIBUTIONS

JECT MILESTONES (DATES)

PROJECT SET-UP	April , 2010

PROJECT DESCRIPTION

COSTS TO INSTALL TEN 45CL3 POLES, THREE 45'CL5 POLES, SIX 50'CL3 POLES, ONE 55'CL3 POLE, FOURTY FOUR 40'CL5 POLES, EIGHT 40'CL3 POLES, THIRTY ANC-T'S, SIXTY ONE ANC-E'S, INSTRUMENT METERING, 3X50KVA/14.4KV/120/208V 3 PH TRANSFORMER BANK, TWO STREET LIGHTS, RELOCATION OF THE EXIST TRANSFORMERS AND STREET LIGHTS ON NEW POLES, STRINGING OF APPROX 15KM OF 4x#1/0 ACSR BY UPGRADING THE EXISTING POLES FROM 1PH TO 3 PH AND SALVAGE OF OLD ONE PHASE LINE AND #4/6 ACSR CONDUCTORS AS PER THE ATTACHED PLANS. CONNECT AND ENERGIZE

ALL FUSES TO BE K TYPE

PROJECT APPROVALS	NAME	SIGNATURES	DATE
ENGINEERING APPROVAL	YESH SHARMA		30-Apr-10
MARKETING APPROVAL	Phil Borgel		30-Apr-10
EXPENDITURE APPROVALS			
E & C SUPERINTENDENT			
CLOSEOUT APPROVAL	Phil Borgel		

ATCO Electric

LINE COMMISSIONING REPORT

DISTRICT	LINE NUMBER	CONTRACTOR	W.O. NUMBER
WATSON LK		ARCTIC POWER	Y11637

TYPE OF LINE

DESCRIPTION CONVERT EXISTING LINE FROM 1Ø TO 3Ø

Brushing completed to company standards.	☐ YES	☐ NO	Brushing Standard SC34-1
Line construction complete.	☐ YES	☐ NO	If NO, complete deficiencies section below
Completed to company standards.	☐ YES	☐ NO	If NO, complete deficiencies section below
Were any design changes made?	☐ YES	☐ NO	If YES, attach changes to as-built
Design changes approved.	☐ YES	☐ N/A	Changes indicated in red on design drawing
Construction inspection report completed.	☐ YES	☐ NO	
All other reports completed:			
S.I.R.	☐ YES	☐ N/A	
EQUIP. REP. #	☐ YES	☐ N/A	
AS BUILT (stamped)	☐ YES	☐ NO	
All tags installed.	☐ YES	☐ NO	If NO, complete deficiencies section below
Ground/ Road / RR/ PL clearance measured.	☐ YES	☐ N/A	Distance measured: 1_____ 2_____ 3_____ 4_____
Left energized.	☐ YES	☐ NO	If YES, approved by _____

DEFICIENCIES

CONSTRUCTION START	Date JUNE 22 /2010	Crew Foreman DAN BONNYCASTLE
RELEASE TO ENERGIZE	Date AUG 11/2010	Crew Foreman DAN BONNYCASTLE
ACCEPTED BY	Date Sept 23/10	Construction Lead
APPROVED BY	Date	O.I.C.
ACCEPTED BY	Date	O&M Representative

SERVICE CONNECTION

Customer _____ Date of hookup _____

Electrical permit received	☐ YES	☐ NO
Meter forms complete	☐ YES	☐ NO

ATCO Electric

CONSTRUCTION INSPECTION REPORT

DATE: Aug 11/2010 CONTRACTOR: Arctic Power
WORK ORDER #: Y11637 LOCATION/LSD: Lower Post.

A: Poles:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Tamping & Backfill		✓		
2. Straightness of Line		✓		
3. Tagged – ATCO		✓		
4. Setting Depth		✓		

B: FRAMING:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. As per staking/drawing		✓		
2. Bonding as per manual		✓		

C: ANCHORING:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Pole rake/kick		✓		
2. As per staking/drawing		✓		
3. Bonding bolts		✓		
4. Bonding between guy downhauls	✓			
	✓			
5. Guy Guards installed		✓		
6. Tight Guy		✓		

D: STRINGING/SAG:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Line Sag		✓		
2. Ties as per staking/drawing		✓		
3. Ground Clearance		✓		spot check for suspicious spans
4. Road/RR/Pipeline Clearance		✓		

E: GROUNDING:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Ground as per staking/drawing		✓		
2. All ground connections completed		✓		
3. Meggered & Tagged		✓		
4. High Voltage sign installed		✓		

F: SWITCHES:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Fuse size tag installed		✓		Fuse Size: Amps:
2. Switch number installed		✓		

G: TRANSFORMER:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. All connections complete/correct		✓		
2. All ground connections completed		✓		
3. Oil leaks/bushings		✓		
4. Voltage		✓		

H: SERVICE CONNECTIONS:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. All connections completed				
2. Grounding is complete/correct				
3. Cabinet & Breaker connections				

ATCO Electric

I: BRUSHING:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Clearance adequate		✓		
2. Clean up ok		✓		

J: URGD XMER/RISER POLE:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Phase tags installed				
2. Danger High Voltage signs installed				
3. Danger Buried Cable signs installed				
4. Warning signs installed				
5. All connections completed				
6. Service address tags installed				
7. Locks installed				
8. Trench settled				

K: SALVAGE WORK:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. All material picked up		✓		
2. All wire rolled up		✓		
3. All holes filled in		✓		
4. All anchors pulled		✓		
5. Site left presentable		✓		

L: DAMAGE:	N/A	ACCEPTABLE	UNACCEPTABLE	REMARKS
1. Ruts		✓		
2. Other		✓		

M: ADDITIONAL WORK TO BE DONE (DEFFIENCIES)

ACTION PLAN	WHO	WHEN

DEFICIENCIES COMPLETED:

REPORT COMPLETED BY: Ian Scrimgeour DATE: Aug 11/2010

REPORT ACCEPTED BY: DATE:

ATCO Electric

June 18, 2010 2:24 PM

Click for Program Properties

Project No.: Y11637
Project Description: NWTel anchors in Lower Post

Revision:
User: Y Sharma

Segment Name	Qty	Structure	#of Cond.	Comments
	26	E190013		ANC PWR S/HELIX 10IN TOUGH ONE
	26	E190480		NUT EYE 3/4" OR 1" ANC ROD ALL
	26	E190680		ROD ANC PWR EXT 5/8 X 3 1/2 FT
	26	ANC-E		

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE		BIN #
26		E190013	8311	ANC PWR S/HELIX 10IN TOUGH ONE			0.00		RD0001
26		E190137	8311	CLAMP BOND POWER/ANC			0.00		B1E006
26		E190480	8311	NUT EYE 3/4" OR 1" ANC ROD ALL			0.00		B3D011
26		E190680	8311	ROD ANC PWR EXT 5/8 X 3 1/2 FT			0.00		#N/A

TASK 8721

Total Unloaded Stocked Material Cost $0
Spot Construction Manhours

Total Loaded Stocked Mat Cost(7%) $0

ATCO Electric

June 15, 2010 3:54 PM

Click for Program Properties

Project No.: Y11637
Project Description: DDC Lower Post Line upgrade to 3 ph and Health Centre

Revision:
User: Y Sharma

Segment Name	Qty	Structure	#of Cond.	Comments
	17.53	#4SB150	4	
	17.53	#1:0	4	
	110	N12		
	55	X0A		
	1	N73B		
	1	NSAS52		
	5	N31		
	1	N75		
	1	N41		
	1	N82		
	1	N54A		
	1	N71		
	24	N50		
	45	R0		
	15	X0B		
	20	N11		
	30	E12		
	6	R154		
	2	R171		
	2	SAS60		
	1	R170		
	1	R182		
	1	R180		
	1	R152		
	0.5	#1:0 AL	1	
	11	X40B		
	4	X408-A1		
	30	ANC-T		
	35	ANC-E		
	30	G10		
	50	G40		
	1	G50		
	3	E340111		TKVA 50 OH 24.9GY/14.4/120/240
	16	E350084		WIRE CU 500MCM STRD RW90 WP
	10	P45-3		
	3	P45-5		
	6	P50-3		
	1	P55-3		
	44	P40-5		
	7	P40-3		
	8	E360017		ARM 2P 5X5X10 GLULAM ANG/BRACE
	3	E260208		BLADE ASSY FOR 25KV 100AMP DISC SWCH
	1	CT200-1		
	3	E340021		T CT 2W 800/5 BAR TYPE
	3	E210011		INDICATOR FAULT AUTO 800A FCI-
	12	E190228		CNTR AMP YELLOW 1-602031-3
	12	E210030		COVER AMP CNTR LARGE 602107
	17	E210048		SHELL AMPACT YELLOW 69338-4

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION		UNIT PRICE		TOTAL PRICE		BIN #
72		E190054	8311	BOLT EYE 5/8X 8 IN GALV				0.00		B1A004
7		E190055	8311	BOLT EYE 5/8X10 IN GALV				0.00		B1A005
46		E190056	8311	BOLT EYE 5/8X12 IN GALV				0.00		B1A006
6		E190057	8311	BOLT EYE 5/8X14 IN GALV				0.00		B1A007
36		E190059	8311	BOLT EYE 5/8X18 IN GALV				0.00		B1A009

1		E190062	8311	BOLT EYE 5/8X24 IN GALV				0.00	B1A013
6		E190073	8311	BOLT LAG 1/2X04 1/2 IN GALV				0.00	B1B003
264		E190078	8311	BOLT MACH 1/2X06 IN GALV				0.00	B1B005
76		E190079	8311	BOLT MACH 1/2X07 IN GALV				0.00	B1B006
13		E190094	8311	BOLT MACH 5/8X10 IN GALV				0.00	B1C007
232		E190095	8311	BOLT MACH 5/8X12 IN GALV				0.00	B1C008
225		E190096	8311	BOLT MACH 5/8X14 IN GALV				0.00	B1C009
132		E190097	8311	BOLT MACH 5/8X16 IN GALV				0.00	B1C010
4		E190108	8311	BOLT MACH 3/4X12 IN GALV				0.00	B1D004
53		E190109	8311	BOLT MACH 3/4X14 IN GALV				0.00	B1D005
2		E190110	8311	BOLT MACH 3/4X16 IN GALV				0.00	B1D006
4		E190115	8311	BOLT MACH 3/4X26 IN GALV				0.00	B1D011
4		E360066	8311	BRKT SWCH MTG ATCO SPEC #10984				0.00	B1E003
10		E190143	8311	CLAMP BAIL 6 TO 1/0				0.00	B1E004
117		E190137	8311	CLAMP BOND POWER/ANC				0.00	B1E006
25		E190168	8311	CLAMP HL SCREW TYPE				0.00	B1E008
265		E190484	8311	CLEVIS FOR PREF DEADEND GRIP				0.00	B1E009
30		E190495	8311	CLEVIS SPOOL TYPE DEAD END				0.00	B1E010
5		E210054	8311	COVER INSULATOR RODENT PROTECT				0.00	B1E011
30		E190187	8311	CNTR GRD ROD 3/4 IN ROD				0.00	B1E012
3		E190278	8311	CNTR BAR TAP XER/SEC				0.00	B1E013
60		E190201	8311	COUPLING GRD/ROD SPEC 9941				0.00	B1E014
80		E190530	8311	FITTING GUY				0.00	B1E015
424		E260214	8311	INSULATOR FOR 1 IN. PIN 25 KV				0.00	B2A004
86		E260220	8311	INSUL SPOOL SL355				0.00	B2A005
212		E260235	8311	INSUL DE 25 KV POLYMERIC				0.00	B2A007
30		E210047	8311	SHELL AMPACT BLUE 69338-1				0.00	B2A009
25		E210048	8311	SHELL AMPACT YELLOW 69338-4				0.00	B2A011
136		E190589	8311	PIN PLTP 24" GALV.				0.00	B2A014
30		E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD				0.00	B2B002
428		E190660	8311	TIE TOP DIST "F" 1/0 RAVEN				0.00	B2B002
60		E190620	8311	GRIP DE PREF 5/16 GUY WIRE				0.00	B2B003
4		E190598	8311	GRIP DE PREF 4 ACSR				0.00	B2B005
6		E190248	8311	CNTR AMP BLUE 600448				0.00	B2B011
11		E190609	8311	GRIP DE PREF 1/0 ALUM WP				0.00	B2C004
62		E190716	8311	WASHER RD GALV FOR 5/8" BOLT				0.00	B2C007
12		E190228	8311	CNTR AMP YELLOW 1-602031-3				0.00	B2C017
261		E190600	8311	GRIP DE PREF 1/0 ACSR				0.00	B2D003
340		E190471	8311	NUT PAL 1/2 INCH GALV				0.00	B2D005
699		E190472	8311	NUT PAL 5/8 INCH GALV				0.00	B2D006
1044		E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8				0.00	B2D007
65		E190473	8311	NUT PAL 3/4 INCH GALV				0.00	B2D008
63		E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4				0.00	B2D009
12		E190704	8311	WASHER LOCK CAD PLATE 1/2 BLT				0.00	B2D014
340		E190715	8311	WASHER RD GALV FOR 1/2" BOLT				0.00	B2E004
833		E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE				0.00	B2E005
17		E190730	8311	WASHER SQ 3X3X13/16 HOLE				0.00	B2E006
340		E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT				0.00	B2E011
12		E210030	8311	COVER AMP CNTR LARGE 602107				0.00	B3A003
8		E300072	8311	SLEEVE SQUEEZON BB WR9				0.00	B3A005
228		E190584	8311	PIN CROSSARM 6" SHANK				0.00	B3A014
40		E190583	8311	PIN CROSSARM ANGLED				0.00	B3A015
4		E200000	8311	CONTRLR P/E FOR STLT. 120 VOLT				0.00	B3B005
4		E260121	8311	FUSE KTK 15A FOR SENT. LIGHT				0.00	B3B006
4		E200035	8311	LAMP HP SODIUM 100W				0.00	B3B009
4		E190597	8311	GRIP DE PREF 6 ACSR				0.00	B3C003
36		E300008	8311	SLEEVE AUTO 1/0 ACSR 6/1				0.00	B3C016
150		E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED				0.00	B3C022
1		E190596	8311	PIN TRANSFORMER				0.00	B3C024
42		E190548	8311	STRAP BONDING 9" T-STD-807 A				0.00	B3D006

9		E190508	8311	GAIN POLE GALV 3/4" BOLT				0.00	B3D008
91		E190466	8311	NUT EYE 5/8 IN GALV				0.00	B3D009
6		E190533	8311	FITTING LINK SL6784 OR EQUIV.				0.00	B3E009
5		E190028	8311	BOLT DA 5/8X20 IN GALV				0.00	B3E017
6		E190032	8311	BOLT DA 5/8X28 IN GALV				0.00	B3E019
3		E190031	8311	BOLT DA 5/8X26 IN GALV				0.00	B3E020
3		E340021	8311	T CT 2W 800/5 BAR TYPE				0.00	B4A006
4		E260347	8311	TAPE ALL-WEATHER ELECTRIC 3/4"				0.00	B4B003
1		E220006	8311	SWCH METER TEST 10PT				0.00	B4B016
118		E300074	8311	SLEEVE SQUEEZON BB WR279				0.00	B6A020
7		E300073	8311	SLEEVE SQUEEZON BB WR159				0.00	B6A024
18		E300075	8311	SLEEVE SQUEEZON BB WR189				0.00	B6A026
13		E260306	8311	SWCH DISC 25KV 100A				0.00	QT0000
30		E160078	8311	COND ROUND 3/4 IN PVC				0.00	RA0001
82		E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH				0.00	RA0001
82		E260255	8311	INSUL GUY STRAIN				0.00	RA0001
30		E190677	8311	ROD ANC 1 X 10 GALV				0.00	RA0001
90		E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941				0.00	RA0001
49		E350080	8311	WIRE CU 2/0 STRD WP				0.00	RB0001
60		E350017	8311	WIRE ALUM*TIE 4				0.00	RB0002
460		E350078	8311	WIRE CU 2 STRD WP				0.00	RB0002
15		E350077	8311	WIRE CU 4 STRD WP				0.00	RB0002
15		E190630	8311	ROD ARMOR FOR 1/0 ACSR RAVEN				0.00	RB0004
104		E190626	8311	GRIP DE PREF 7/16 GUY WIRE				0.00	RC0002
16		E350076	8311	WIRE ALUM 8 PJ STLT				0.00	RC0002
35		E190013	8311	ANC PWR S/HELIX 10IN TOUGH ONE				0.00	RD0001
5		E260003	8311	ARRSTR 25KV HD DIST POLYMER				0.00	RF0004
3		E260209	8311	BLADE ASSY FOR 25KV DISC SWCH				0.00	RF0005
21		E190476	8311	NUT SQ 5/8 INCH GALV				0.00	RG0002
7		E350051	8311	WIRE TW 12 CU BLUE STRD				0.00	RJ0003
7		E350056	8311	WIRE TW 12 CU BLUE/BLACK STRD				0.00	RJ0003
1		E350052	8311	WIRE TW 12 CU GREEN STRD				0.00	RJ0003
7		E350053	8311	WIRE TW 12 CU RED STRD				0.00	RJ0003
7		E350058	8311	WIRE TW 12 CU RED/BLACK STRD				0.00	RJ0003
7		E350059	8311	WIRE TW 12 CU RED/WHITE STRD				0.00	RJ0003
7		E350054	8311	WIRE TW 12 CU WHITE STRD				0.00	RJ0003
7		E350055	8311	WIRE TW 12 CU YELLOW STRD				0.00	RJ0003
7		E350060	8311	WIRE TW 12 CU YELLOW/BLACK STR				0.00	RJ0003
7		E350061	8311	WIRE TW 12 CU YELLOW/WHITE STR				0.00	RJ0003
7		E350057	8311	WIRE TW CU BLUE/WHITE STRD				0.00	RJ0003
4		E200051	8311	LUM INT/BLST 100W HPS RECP,GE				0.00	RK0002
30		E190000	8311	ANCHOR XPLATE 24 IN				0.00	YA0001
170		E360029	8311	BRACE ANGLE ARM 42 INCH B.C.				0.00	YA0001
1		E360068	8311	BRKT TRANS 3 WAY CLUSTER MOUNT				0.00	YA0001
360		E350029	8311	WIRE GUY 5/16 GRADE 180 COILS				0.00	YA0001
790		E350031	8311	WIRE GUY 7/16 GRADE 180 COILS				0.00	YA0002
71000		E350001	8311	WIRE ACSR 1/0 6/1 RAVEN				0.00	YA0003
500		E350073	8311	WIRE ALUM 1/0 STRD WP				0.00	YA0005
80		E350084	8311	WIRE CU 500MCM STRD RW90 WP				0.00	YA0006
4		E200092	8311	BRKT STLT WOOD POLE 2"IPSX41"L				0.00	YA0009
44		E360117	8311	POLE 40 FT CLASS 5				0.00	YA0018
3		E360118	8311	POLE 45 FT CLASS 5				0.00	YA0018
7		E360075	8311	POLE 40 FT CLASS 3				0.00	YA0019
10		E360080	8311	POLE 45 FT CLASS 3				0.00	YA0019
1		E360090	8311	POLE 55 FT CLASS 3				0.00	YA0022
2		E360015	8311	ARM 2P 4X5X8 GLU/LAM SLACKSPAN				0.00	YB0001
8		E360017	8311	ARM 2P 5X5X10 GLULAM ANG/BRACE				0.00	YB0001
38		E360020	8311	ARM 2P 5X5X7 GLU/LAM ANG/BRACE				0.00	YB0001
130		E360012	8311	ARM 2P GLU/LAM 7FT ANG/BRACE				0.00	YB0001
3		E340111	8333	TKVA 50 OH 24.9GY/14.4/120/240				0.00	YB0003

1		E260303	8311	SWCH GANG 27KV 900A AR TYPE				0.00	YB0017
6		E360085	8311	POLE 50 FT CLASS 3				0.00	YB0021
4		E360126	8311	TIMBER 6X 8X20				0.00	YF0001
12		E190461	8311	NUT HEX PLATED 1/2" UNC				0.00	Z00000
3		E260208	8311	BLADE ASSY FOR 25KV 100AMP DISC SWCH				0.00	#N/A
12		E190025	8311	BOLT PLATED 1/2X1-1/2 GR 5 NC				0.00	#N/A
6		E190317	8311	CNTR HYLUG BURNDY YA26A3 2/0				0.00	#N/A
6		E190758	8311	DEADEND STRAIGHT LINE CLAMP HOT				0.00	#N/A
81		E320050	8311	DISPENSOR GUY WIRE (CAGES)				0.00	#N/A
450		E190897	8311	FENCE STAPLES, HOT DIP GALVANIZED 1 3/4"				0.00	#N/A
4		E260102	8311	FUSE HOLDER INLINE 2-2 HEB-RR				0.00	#N/A
20		E190588	8311	PIN PLPT CORNER 24"X 30D ANGLE				0.00	#N/A
36		E300004	8311	SLEEVE AUTO 4 ACSR SB 150% LENGTH 8.5"				0.00	#N/A
50		E190700	8311	WASHER CURVED 3 IN 13/16 H				0.00	B3A005
12		E190714	8311	WASHER RD CAD PLTD 1/2" BOLT				0.00	#N/A
6		E190906	8311	WEDGE DEAD END SIDE OPENING FOR # 4 TO 1/0 ACSR				0.00	#N/A
3		E210011	8321	INDICATOR FAULT AUTO 800A FCI-				0.00	#N/A
									#N/A

Total Unloaded Stocked Material Cost $0
Spot Construction Manhours

Total Loaded Stocked Mat Cost(7%) $0

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BRR-10 AUG 7 01A

5L619 S2499 S2984

*** Medium Loading Design**

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
222	exist			45ft	cl.3	exist: N31, (2) anc	**Sw # S2996, Fuse 1A, K Type**
					1990	**chng to SAS52, add: (2)G40, anc-E**	remove anc to the south 5A
		104.3				**chng tap to N54, N71**	* UG cable locate
221	exist			45ft	cl.3	exist: 1ph OCR, G10, anc	**Salvage exist OCR**
		9.2			1991	**add: N12, G10, adjust X0-A as reqd**	use exist anc, add new G10
21976	exist			45ft	cl.3	Salvage exist R112, R182, X40B,10kva T x	Salvage pole and all hardware
		80.4			2006		
23501	#5-A			**45ft**	**cl.3**	**N50, (2)R0, (2)G40, anc-T**	*temporary stringing point
		2				***don't use guy strain's**	string 4 x 1/0 ACSR, 8 meters anchor
220	exist			45ft	cl.3	Salvage exist: R112	Salvage pole
		91.7			1978		
219	exist			40ft	cl.4	exist: R111, **change to N12**	use existing pole top pin & insulator
		91.2			1993		
218	exist			40ft	cl.4	exist: R112, **change to N12**	use existing pole top pin & insulator
		70.2			1993		
217	exist			40ft	cl.4	exist: R112, **change to N12**	use existing pole top pin & insulator
		100.3			1993		
216	exist			40ft	cl.4	exist: R112, G10, anc	use existing pole top pin & insulator
		99.9			1993	**Chbg exist R112 to N12, Add: X0B**	2°33'52"<LT
215	exist			40ft	cl.4	exist: R112, G10, anc	remove pole top pin & insulator
		100.1			1993	**chng exist R112 to N11, E12, Add: X0B**	9°04'44"<LT
214	exist			40ft	cl.4	exist: R112, G10, anc	remove pole top pin & insulator
		100			1993	**chng exist R112 to N11, Add: X0B**	6°16'30"<LT
213	exist			40ft	cl.4	exist: R112, G10, anc	remove pole top pin & insulator
		100			1993	**chng exist R112 to N11, Add: X0B**	5°45'15"<LT
212	exist	SAG		40ft	cl.4	exist: R112, G10, anc	remove pole top pin & insulator
		100.1			1993	**chng exist R112 to N11, Add: X0B**	7°22'32"<LT
211	exist			45ft	cl.3	exist: R112, E12, G10, anc	remove pole top pin & insulator
		98.9			1988	**chng exist R112 to N11, Add: X0B**	7°23'33"<LT
210	exist			40ft	cl.4	exist: R112, G10, anc	use existing pole top pin & insulator
		100			1993	**Chbg exist R112 to N12, Add: X0B**	2°31'11"<LT
209	exist			40ft	cl.4	**Change exist R112 to N12**	
		99.8			1993		use existing pole top pin & insulator
208	exist			40ft	cl.3	**Change exist R112 to N12**	
		100.4			1993		use existing pole top pin & insulator
207	exist			40ft	cl.4	**Change exist R112 to N12**	
		100.1			1993		use existing pole top pin & insulator
206	exist			40ft	cl.4	exist: R112	remove pole top pin & insulator
		99.2			1993	**chng exist R112 to N11, Add: X0B**	8°39'31"<RT

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*** Nwtel anchoring added to project**

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
205	exist			45ft	cl.3 1980	**Change exist R112 to N12**	use existing pole top pin & insulator
204	exist	100.2		40ft	cl.4 1993	Salvage exist: R112, G10, anc **add: N12, X0-A**	remove X40B, G10, anc use existing pole top pin & insulator
23502	#5	75.1		**50ft**	**cl.3**	**N31, (2)R0, E12, (4)G40, (2) anc-T** *** 9m DE ANCHORS REQ'D** **add: (2)anc-E for Nwtel (7.5m anchhor)**	*** see G25 for 7/16" guying senario anchor staked at 8 m, adjust to 9m** 91°56'39"<RT
23503	#6	44.7		**50ft**	**cl.3**	**N31, (2)R0, (4)G40, (2) anc-T** *** 9m DE ANCHORS REQ'D** **add: (2)anc-E for Nwtel (7.5m anchhor)**	*** see G25 for 7/16" guying senario anchor staked at 8 m, adjust to 9m** 78°32'58"<LT
23504	#7	97.1		**55ft**	**cl.3**	**N12, X0-A, R154, R71, G10, anc-E**	**Sw# 8046, fuse: 5A , K Type** Use new sw plate with same number on new pole
23505	#8	66.3		**40ft**	**cl.5**	**N12, X0-A, E12**	
23506	#9	88.2		**40ft**	**cl.5**	**N12, X0-A**	**set pole 7ft deep to help profile**
184	exist	106.2		40ft	cl.3 2006	exist: R112 **change to N50, (2)R0** **add: (2)G40, anc-T, anc-E**	use existing pole top pin & insulator * temporary stringing is anc-T 3°18'58"<RT
183	exist	97.8		45ft	cl.3 2006	exist: R112, E12 **chng to N12, N73B, add: X0-A**	**Sw# S3004, Fuse: Gang switch** **install 3 new fault indicators south**
182	exist	89.1		40ft	cl.3 2006	exist: R112, G10, anc-E **change to N50, (2)R0** **add: Anc-E for Nwtel to exist anc** **do not add guy strain**	use existing anchors installed use existing pole top pin & insulator 6°51'39"<RT
23507	#10	68.5		**40ft**	**cl.3**	**N50, (2)R0, (2)G40, anc-T, anc-E** **add anc-E for Nwtel on defl.** **do not add guy strain**	6°13'44"<LT
23508	#11	109.1		**50ft**	**cl.3**	**N12, X0-A**	
23509	#12	109.4		**50ft**	**cl.3**	**N12, X0-A, E12**	
23510	#13	95.9		**40ft**	**cl.3**	**N50, (2)R0, (2)G40, anc-T, anc-E** **add: anc-E for Nwtel on defl.** **do not add guy strain**	use anc-T for DE anchor 4.5 meters Nwtel anchor 17°36'00"<RT
23511	#14	97.3		**40ft**	**cl.5**	**N11, X0-B, G10** **Nwtel to use exist anchor, use guy guard**	use existing anchor & guy guards 9°18'08"<RT
176	exist	92.3		40ft	cl.4 1988	exist: R122, G10, anc **chng to N11, Add:G10, use exist anchor**	remove pole top pins & insulators 13°50'17"<RT
175	exist	94.9		40ft	cl.3 1988	exist: R122, G10, anc **chng to N11, Add: E12, G10, use exist anchor**	remove pole top pins & insulators 14°02'03"<RT
174	exist	113.4		35ft	cl.3 1988	exist: R122, G10, anc **chng to N11, Add:G10, use exist anchor**	remove pole top pins & insulators 14°27'49"<RT
173	exist	95.4		35ft	cl.3 1988	exist: R112, G10, anc **chng to N11, Add:G10, use exist anchor**	remove pole top pin & insulator 4°20'26"<RT
		98.5					

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*** Nwtel anchoring added to project**

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
172	exist			35ft	cl.3 1988	**Change exist R112 to N12**	use existing pole top pin & insulator
171	exist	98.8		35ft	cl.3 1988	**Change exist R112 to N12**	use existing pole top pin & insulator
170	exist	97.2		35ft	cl.3 1988	**Change exist R112 to N12**	use existing pole top pin & insulator
169	exist	98.9		35ft	cl.3 1988	**Change exist R112 to N12**	remove existing sky pin & insulator
168	exist	97.9		35ft	cl.4 1985	**Change exist R112 to N12**	use existing pole top pin & insulator 2°29'00"<RT
167	exist	91.8		45ft	cl.4	**Build SAS60, add: (3)anc-T, anc-E,**	*** See notes on const. plan/detail** 2°15'18"<LT. Install new sw plate(S2997) for existing 25 KVA Tx, Fuse 2.5A K Type
23512	#16	202		**45ft**	**cl.3**	**(6)G40, (2)R0**	
166 23513	exist #17	105.8		45ft **45ft**	cl.3 **cl.3**	remove guy wires on gulley side **Build SAS60, add: (2)anc-T (5)G40, (2)R0 Add: anc-E, for Nwtel DE**	*** See notes on const. plan/detail** 11°10'54"<LT
165	exist	100.9		40ft	cl.4 1979	exist: R112, G10, anc **chng to N11, Add:G10, use exist anchor**	remove existing sky pin & insulator 5°47'20"<LT
164	exist	108.8		40ft	cl.3 1992	**Change exist R112 to N12**	use existing pole top pin & insulator
163	exist	103.1		40ft	cl.3 1992	**Change exist R112 to N12**	use existing pole top pin & insulator
23514 162	#18	109		**45ft**	**cl.5**	**N11, X0-B, G10 add: Anc-E without guy strain for Nwtel**	change out exist pole, Use exist anchor 7°00'02"<RT
23515 161	#19	103.8		**45ft**	**cl.5**	**N12, X0-B, G10, anc-E add: anc-E for NWtel exclude guy strain**	2°00'34"<RT
1995	exist	123.9		40ft	cl.3 1980	exist: R152, (2)G10, (2) anc **chng to N50, use 10ft xarm add: anc-T, G40, (2) guy gaurds**	use existing pole top pin & insulator *** do not string to full DE tension** 14°03'28"<RT
159	exist	77.4		40ft	cl.3 1989	exist: R152, E12, (2)G10, (2) anc **chng to N50, use 10ft xarm move exist guy to nuetral posiiton**	use existing pole top pin & insulator *** do not string to full DE tension** 16°28'12"<LT
1994	exist	80		40ft	cl.2 1996	**Salvage exist R112 Add: N11 Use same anchor and guy**	remove existing sky pin & insulator 5°53'20"<LT
158	exist	100		40ft	cl.2 1994	**Salvage exist R112 Add: N11 Use same anchor and guy**	remove existing sky pin & insulator 9°48'56"<LT
157	exist	100		40ft	cl.3 1997	**Salvage exist: R122 Add: N11 Use same anchor and guy**	remove existing sky pins & insulators 17°56'54"<LT
156	exist	99.5		40ft	cl.3 1997	exist: R122, E12, G10, anc-E **change to N50, Add: G50, Use same anchor**	use one exist sky pin & insulator 21°00'50"<LT
155	exist	97.8		40ft	cl.3 1982	**Change exist R112 to N12**	use existing pole top pin & insulator

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YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
154	exist			40ft	cl.4 1983	**Change exist R112 to N12**	use existing sky pin & insulator
153	exist	100.1		40ft	cl.2 1996	**Change exist R112 to N12**	use existing sky pin & insulator
152	exist	100.4		40ft	cl.3 1997	**Change exist R112 to N12**	use existing sky pin & insulator
151	exist	100		40ft	cl.3 1991	**Change exist R112 to N12**	use existing sky pin & insulator
150	exist	99.9		40ft	cl.2 1994	**Change exist R112 to N12**	use existing sky pin & insulator
~~149~~	~~exist~~	99.8		40ft	cl.2	exist: R112 **chng: N50 add: anc-E, G40, E12, (2)R0**	0°35'14"<LT remove anchor and guy once stringing is complete
2,045.2M		87.7			1994	install anc-T, G40, temp stringing only	
23516	~~#21~~	87.2		40ft 40	cl.5 3	N12, X0-A	STAGED FOR ANC ? INLINE TOWARDS 149
23517	#22	88		40ft	cl.5	N12, X0-A	
23518 5M	~~#23~~	80.3		45ft	cl.5	N12, X0-A, R182, E12, X40B **Relocate existing Tx on this pole**	**Sw: S2084, Fuse 1 A K Type** Refeed St light from new pole
23519	#24	86.5		40ft	cl.5	N12, X0-A	
23520	#25	85.6		40ft	cl.5	N12, X0-A	
23521	#26	86.2		40ft	cl.5	N12, X0-A	
23522 13M	~~#27~~	86.9		40ft	cl.5	N12, X0-A, E12	
23523	#28	85.5		40ft	cl.5	N12, X0-A	
23524	#29	86.3		40ft	cl.5	N12, X0-A	
23525	~~#30~~ ?	85.9		40ft	cl.3	N50, (2)R0 STRING THROUGH NO ANC ~~add anc-T, G40, temp stringing~~	* ~~Temp stringing point~~ ~~remove anchor and guy once stringing is~~ complete
23526 9M	~~#31~~	86.5		40ft	cl.5	N12, X0-A, E12	
23527	#32	86.2		40ft	cl.5	N12, X0-A	
23528	#33	86		40ft	cl.5	N12, X0-A HOE	
		1,117.1M					

1,718.9M
STR 21-40

TAN ||||-|||| -||| -||| -||| -|||| -|| 12
ANGLE |||| -|||| -||| 9
DOE |||| -| 6
10' 11
N31 1

STR #21 CHANGED TO DOE INSTEAD OF EXIST #149

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STAKING LIST

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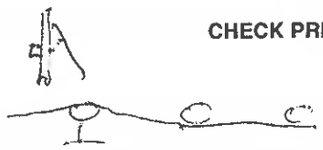

Project Number: Y11637 Lowerpost Health Centre 3ph
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* Nwtel anchoring added to project

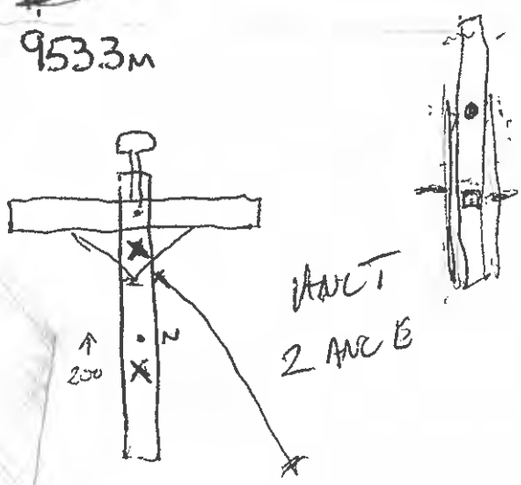
YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
23529	#34	86.3		40ft	cl.5	N12, X0-A HOE	
23530	~~#35~~	86.3		40ft	cl.5	N12, X0-A, E12 HOE	
23531	#36	87		40ft	cl.5	N12, X0-A HOE	
23532	#37	85.7		40ft	cl.5	N12, X0-B, G10, anc-E LOCATE	* Require Nwtel Locate for anchor 1°29'40"<RT
23533	#38	84.8	X	45ft	cl.5	N12, X0-A DONT SET/FRAME	
23534	~~#39~~	84		40ft	cl.5	N12, X0-A, E12 HOE	
23535	#40	118	X	40ft	cl.3	N50, (2)R0, use 10ft xarm CANT FRAME add: anc-T, anc-E, (2)G40 add: anc-E for Nwtel DE	* do not string to full DE tension 10°33'02"<LT
131	~~exist~~	65.4		45ft	cl.5 1996	exist: R152 chng to N50, (2)R0, use 10ft xarm CANT FRAME add: (2)anc-E, (2)G10	* do not string to full DE tension install below nuetral in line
23536	#41	82.1		40ft	cl.3	N50, (2)R0, anc-T, anc-E, (2)G40 2	* stringing point - anchor can remain 9°53'19"<LT
23537	~~#42~~	88.6		40ft	cl.5	N12, X0-B, E12, anc-E, G40 add: anc-E for Nwtel DE	2°24'10"<LT
23538	#43	82.4		40ft	cl.5	N12, X0-A	
23539	#44	87.8		40ft	cl.5	N12, X0-B, G10, anc-E	very short 2.5m anchor 0°50'59"<RT
23540	#45	86.6		40ft	cl.5	N12, X0-A	Caustion Burried NWTel cable 3 meters away
23541	~~#46~~	87.1		40ft	cl.5	N12, X0-A, E12	Caustion Burried NWTel cable 3.2 meters away
23542	#47	87.2		40ft	cl.5	N12, X0-A	
23543	#48	86.6		40ft	cl.5	N12, X0-A	
23544	#49	87.7		40ft	cl.5	N12, X0-A	
23545	~~#50~~	87		40ft	cl.5	N12, X0-A, E12	
23546	#51	90.2		40ft	cl.5	N12, X0-A	

718.9M

1,734.3M

953.3M

STR#41-61 = (1,734.3M)



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1470 MM

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41-61 = (1,734.3M) 86.7M RULING

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
23547	#52	89.7		40ft	cl.5	N12, X0-A	
23548	#53	89.7		40ft	cl.5	N12, X0-A	
23549 X	#54 10m	90.4		40ft	cl.3	N50, (2)R0, E12 STRING THROUGH ~~add anc-T, G40 temp stringing anc~~	* ~~Temp stringing point~~ anc-T for DE
23550	#55	83.3		40ft	cl.5	N12, X0-A	
23551	#56	84.3		40ft	cl.5	N12, X0-A	
23552	#57	84		40ft	cl.5	N12, X0-A	
23553 X	#58 7m	84.1		40ft	cl.5	N12, X0-A, E12	
23554	#59	91.3		40ft	cl.5	N12, X0-B, G10, anc-E	caution straddling UG cable w/ anc 4.5 m anchor
23555	#60	84.2		40ft	cl.5	N12, X0-A	
		78.4				3,548.9 M TOTAL	
23556 X	#61	103.6		40ft	cl.3	N50, (2)R0, anc-E, anc-T, (2)G40 1,158	anc-T for dDE 6°53'28"<LT
111 X	exist 11m	87.1		35ft	cl.4 1983	exist: R112 **chng to N11, add E12**	remove existing sky pin & insulator 10°25'56"<RT
113	exist	88		35ft	cl.4 1983	exist: R112 **chng to N11, Use exist anchor &Guy**	remove existing sky pin & insulator 7°11'41"<RT
112	exist	84.1		35ft	cl.4 1983	exist: R112 **chng to N11, Use exist anchor &Guy. Raise Guy if required**	remove existing sky pin & insulator 6°18'19"<RT
111	exist	86.1		35ft	cl.4 1983	exist: R112 **chng to N11, Use exist anchor &Guy. Raise Guy if required**	remove existing sky pin & insulator 7°38'30"<RT
110 X	exist 3m	82.6		35ft	cl.4 1983	exist: R112, E12 **chng to N11, Use exist anchor &Guy. Raise Guy if required**	remove existing sky pin & insulator 5°36'12"<RT
109 X	exist	100.1		40ft	cl.5 1974	exist: R112 **chng to N11, Use exist anchor &Guy. Raise Guy if required**	remove existing sky pin & insulator 6°02'04"<RT
108 X	exist	127		45ft	cl.3 1983	exist: R112 **chng to N50, use 10ft arm add anc-E, G10 inline to pole #107**	* do not string to full DE tension pole is a floater, add downhaul
107 X	exist 20m	97.5		35ft	cl.4 1983	exist: R112F **chng to N50, use 10ft arm, add E12 add: anc-E, G10, short defl anchor**	salvage xarm 6°13'42"<LT
106	exist	84.5		35ft	cl.4	**Change exist R112 to N12**	use existing sky pin & insulator

SIR 41-61

734.3M X

31.6M

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YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
105	exist	76.7		35ft	cl.4 1986	**Change exist R112 to N12**	use existing sky pin & insulator
104	exist	141.5		40ft	cl.4 1982	exist: R112 **chng to N50, use 10ft xarm** **add: anc-T, anc-E, (2)G40**	* do not string to full DE tension use existing sky pin & insulator 5°31'11"<LT. Need access to the pole
103	exist 8	74.4		35ft	cl.4 1985	exist: R112 **chng to N50, use 10ft xarm** **add: anc-T, G40, E12**	* do not string to full DE tension
23557	#62 L	31.1		**40ft**	**cl.5**	**N12, X0-A**	
102	exist	42.4		35ft	cl.4 1985	exist: R112, **salvage pole**	
23558	#63 L	73.7		**40ft**	**cl.5**	**N12, X0-A**	
101	exist 6	69.1		35ft	cl.4 1985	**Change exist R152 to N12, Add: E12** **Salvage anchors**	remove anchors use existing sky pin & insulator
100	exist	68.3		40ft	cl.3 1995	**Change exist R112 to N12**	use existing sky pin & insulator
99	exist 11	113.7		40ft	cl.4 1995	**Change exist R152 to N50**, E12, (3) G10, anc **lower inline anc's to below nuteral**	use existing sky pin & insulator 9°17'30"<LT
98	exist	113.8		40ft	cl.2 1995	**Change exist R152 to N50**, (2) G10, (2) anc **lower anchors below nuetral**	use existing sky pin & insulator
97	exist	114.2		40ft	cl.3 1995	**Change exist R122 to N11**, G10, anc **Use same anchor**	remove sky pin & insulator 10°44'42"<LT
96	exist	100.5		40ft	cl.3 1995	**Change exist R152 to N50**, (3)G10, (3)anc **lower anchor guys**	use existing sky pin & insulator 5°32'39"<LT
95	exist	100.5		40ft	cl.4 1995	**Change exist R152 to N50, Add: E12**, (3)G10, (3)anc **lower anchor guys**	use existing sky pin & insulator 5°33'00"<LT
94	exist	100.5		40ft	cl.3 1995	**Change exist R122 to N11**, G10, anc **Use same anchor**	remove sky pin & insulator 8°50'57"<LT
93	exist	102.8		40ft	cl.3 1995	**Change exist R112 to N12**	use existing sky pin & insulator Streighten pole
92	exist	101.5		40ft	cl.4 1995	**Change exist R112 to N12**, (2)G10, (2)anc	use existing sky pin & insulator
91	exist	101.4		40ft	cl.5 1995	**Change exist R112 to N12, Add: E12** EXISTING	use existing sky pin & insulator
90	exist	101.7		40ft	cl.3 1995	**Change exist R112 to N12**	use existing sky pin & insulator
89	exist	102.8		45ft	cl.4 1995	**Change exist R112 to N12**, (2)G10, (2)anc	use existing sky pin & insulator

91 - 92
93 → 95
96 - 98

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YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
88	exist	100.9		40ft	cl.3 1995	**Change exist R152 to N50,** (2)G10, (2)anc	use existing sky pin & insulator
87	exist	101.2		40ft	cl.3 1995	**Change exist R152 to N50** (2)G10, (2)anc, E12 **lower anchor guys**	use existing sky pin & insulator
86	exist	100.2		40ft	cl.3 1995	**Change exist R112 to N12**	use existing sky pin & insulator
85	exist	102.8		40ft	cl.3 1995	**Change exist R112 to N12**	use existing sky pin & insulator
84	exist	101.2		40ft	cl.4 1995	**Change exist R112 to N12**	use existing sky pin & insulator
83	exist	101.2		45ft	cl.3 1995	**Change exist R112 to N12** E12 EXISTING	use existing sky pin & insulator
82	exist	94.2		40ft	cl.2 1995	**Change exist R112 to N11,** G10, anc **Use existing anchor**	remove sky pin & insulator 7°05'48"<LT
81	exist	95.1		40ft	cl.2 1995	**Change exist R112 to N11,** G10, anc **use existing anchor**	remove sky pin & insulator 9°18'27"<LT
80	[illegible]	63.7		40ft	cl.2 1995	**Change exist R112 to N11** **Add: E12** **Use same anchor**	remove sky pin & insulator 9°19'14"<LT
23559	#64	60.1		**40ft**	**cl.5**	**N12, X0-A**	
23560	#65	10.1		**40ft**	**cl.3**	**N31, (2)R0, anc-T, (2)G40** FIBRE TO **top xarm slack & solid connection** CLOSE	*** see G25 for 7/16" guying senario** 62°28'00"<RT
23561	#66	29.7		**40ft**	**cl.3**	**N31, (2)R0, anc-T, (2)G40, X40B top xarm slack & solid connection**	*** see G25 for 7/16" guying senario** 77°29'57"<RT
Exist 78	exist	90.9	55° 2M	40ft	cl.2 1995	GENERATOR DIDNT GO ON THIS POLE Salvage exist R140, R154, R71, Leave X408, (2)X40B **Add: N12, X0A, R180, R170, E12, 150KVA/14.4KV/120/240V 1ph Transformer. Add:N75, Fuse: Solid Barrells, when generator is no longer required.**	Sw# S8047 12 A K Type, for temp. generator and use solid barrells for permanent installation This pole will be used for Temp Generator connection point re-use existing sky pin & insulator
Exist 77	exist	93.9		40ft	cl.3 1995	**Change exist R112 to N12, Leave secondary st lts attachements as is**	use existing sky pin & insulator
Exist 76	exist	92		40ft	cl.3 1995	**Change exist R112 to N12, Leave secondary st lts attachements as is**	use existing sky pin & insulator
Exist 75	exist	92.9		40ft	cl.3 1995	**Change exist R112 to N12, Leave 10KVA Tx and secondary st lt attachements as is**	use existing sky pin & insulator
Exist 74	exist	92.5		40ft	cl.3 1995	**Change exist R112 to N12, Leave secondary st lts attachements as is**	use existing sky pin & insulator
Exist 73	exist	93		40ft	cl.2 1995	**Change exist R112 to N12, Leave secondary st lts attachements as is**	use existing sky pin & insulator
23562	#67	1		**45ft**	**cl.3**	**N50, (2)R0, (3)X40B, X408-A1, (2)R154, R71** GENERATOR ACROSS FROM THIS POLE. Salvage existing anchor **add: temp anc-T, G40** Add: Anc-E, for NWTel	Sw# S2998 fuse: 8A K Type string 1X#1/0 Al o.w. to pole # 68 if using this as stringing point

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*** Nwtel anchoring added to project**

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
none	exist	79.4		35ft	cl.4 ??	exist: R140 w/ offset pin, see pic salvage hardware, cut pole above Nwtel	exist Nwtel riser **Begin Stage 6**
23563 8m	#68 X	79.8	~	**45ft**	**cl.5**	**N12,(2)X0-A, E12, X408-A1, anc-E, G10**	relocate st lt to here DE 1X#1/0 AL o.w. on this pole
23564 ~	#69 X	80.9		**40ft**	**cl.5**	**N12, (2)X0-A, X408-A1, Anc-E, G10**	Install new 100 W St Lt string new 1X#1/0 AL OW to feed St Lt.
23565	#70 X	79.8		**50ft**	**cl.3**	**N12, (2)X0-A, X408-A1**	Install new 100 W St Lt string new 1X#1/0 AL OW to feed St lt
23566 13m	#71 X	79.5	1	**45ft**	**cl.5**	**N12, (2)X0-A, E12, X408-A1, anc-E, G10**	relocate st lt to here string new 1X#1/0 AL OW to feed St lt
23567	#72 X	79.9	/	**45ft**	**cl.5**	**N12, (2)X0-A, X408-A1**	relocate st lt to here string new 1X#1/0 AL OW to feed St lt
23568	#73 +	10642 M 2128-4 47.1m 10m		**50ft**	**cl.3**	**N31, (2)R0, R154, (4)G40, (2)anc-T X408-A1, (2)X40B** 8 meters anchors staked, adjust to 9 meters **add: (2)anc-E for Nwtel DE**	R154 off bottom xarm location 62°34'38"<LT 53299 8AK 1ØTAP DE new 1X#1/0 AL OW to feed St lt on this pole
#43	exist			**45**	**2 1998**	Exist R131, (2) Anc-E, (2) G10, R182 **swing exist #4 ACSR conductors and #6 Duplex to pole #73, Add: (2) Anc-E, for NwTel**	Add new sw plate for exist Tx, S2999, Fuse 2.5 A K Type, feed street lights on poles 73,72,71 70,69 and 68 from this transformer
#16	exist			**45**	**5 0**	**ADD: Anc-E, NWTel anchor to the West**	No electrical changes on this pole
23568	#73					**AS ABOVE**	
none X	exist "A"	83.1		40ft	cl.2 1999	**Change exist R112 to N12, R154 (solid) to R158, Add:G10, anc-E, X40B, X0B** **add: anc-E, G10 for Nwtel take off**	lower neutral as req'd. Add anchor for Duplex Sw# S3000, fuse: 8A k Type 2°31'39"<LT
45 X	exist	56.2		40ft	cl.3 1997	exist: R112F, R182, X40B **add: sky pin & insulator, X0-A**	Add new switch plate (S3001), fuse 2.5 A K type for exist 25 KVA Tx
23569	#74 X	75.6	~	**45ft**	**cl.3**	**N31, (2)R0, (4)G40, (2)anc-T** **add: (2)anc-E for NWTEl DE**	79°40'00"<LT
23570	#75 8m	40.7	~	**45ft**	**cl.3**	**N11, R182, X0-B, anc-E, G10, (2)X40B** **move exist 25kva xmer here** **add: anc-E, G10 for Nwtel defl**	Sw# S3002 fuse: 2.5amp k Type 11°14'15"<LT
23571	#76 6m	36.4	~	**45ft**	**cl.3**	**N41, N82, E12, (2)G40, anc-T, X392** **add: R152, middle phase carry-on** **install 3x 50kva/14.4KV/120/208V 3 ph transformer bank** ADD ANC E FOR NWTEL DE	Sw# S3003 fuse: 5A K Type Customer owned 3ph secondary riser on YECL pole.
49	exist			40ft	cl.4 1982	no change	

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YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type	Comments
	Exist "A"			40	2 98	**See Sheet # 9 for the changes on this pole**	
	Exist # 58	59		40	5	Exist R112, R182, 50KVA Tx, X40B **Add: X40B**	string # 6 Duplex between pole Exist A and #58
	Exist "B"	34		25'	??	Salvage exist X30B	Salvage pole salvage exist duplex
	Exist 1743	22		?	?	X408-A1	refeed this light from pole Exist A
	Exist # 58					AS ABOVE	
	Exist # 59	56				**ADD: (2) Anc-E for NwTel**	
	Exist "C"	64				**ADD: (2) Anc-E for NwTel**	
	Exist "D"	90				NO CHANGE ON THIS POLE	
	Exist "E"	83				**Change exist deflection structure to R140** **Add: Anc-E, G10**	Leave O/H guy for Nwtel attachment salvage primary between poles Exist "G" and "E"
	Exist "F"	97				Slavge exist R110, raise st lt on pole Nwtel to use the existing deflection anchor	NWTel to raise their wires
	Exist "G"	105m		35	4	Exist (2)R140, R154, R182, (2)X40B 10KVA Tx, **Salvage exist R140 to West, Add: Anc-E, G10 and also** Anc-E for NWTel	salvage 10 KVA Tx once Tx at pole 78 is energized
23572	~~#~~ 78	31		**40**	**3**	**R112, R170, R180, E12, X40B** **10KVA/14.4KV/120/240V 1ph Tx**	Set new pole in line. Sw # S2758, Fuse: 1A K Type string # 2 Triplex between poles Exist G and new # 78

1500M
LP 2.

Yukon Electrical
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DISTRIBUTION DEPARTMENT
PROJECT HEADER REPORT

GENERAL INFORMATION

PROJECT NUMBER	Y11969
PROJECT NAME	Hot Springs Road 3 Phase Upgrade
PROJECT DESCRIPTION	Upgrade Hot Springs Road tap from 1ph to 3ph for first 2 kilometers.
APPROPRIATION	70004
ASSET PLANT	
PROJECT STATUS	A
REGION	
DISTRICT	Yukon
SERVICE POINT	Whitehorse
PROJECT LEAD	Cullingham
PROJECT REQUESTED BY	Operations
CUSTOMER CONTACT	Cullingham
CUST. CONTACT PHONE	633-7037

METERING AND SERVICES

NUMBER OF SERVICES	
METERING STANDARD	
METERING TYPE	
CT RATING	
PT RATING	
FARM BREAKER SIZE	
PHASES	
SECONDARY VOLTS	
CUST. OPER. KVA	
RATE CLASS CODE	
TOTAL TRANSFORMER KVA	

ESTIMATED BURDENED COSTS

EASEMENTS	
SURVEY	
BRUSHING	
MATERIAL	
MATERIAL HANDLING	
CONSTRUCTION LT&E	
PROJECT LT&E	
MISCELLANEOUS CHARGES	
DEMOLITION & SALVAGE	
CAPITAL ADJUSTMENTS	
TOTAL PROJECT ESTIMATE:	$0

OTHER COSTS (for info only)

SYSTEM COST CONTRIBUTIONS	

PROJECT MILESTONES (DATES)

PROJECT SET-UP	
PROPOSAL REQUESTED	
CUST. REQUESTED ISD	
FIELD CHECK RECEIVED	
ESTIMATE TO MARKETING	
TARGET RELEASE DATE	

Printed (mm-dd-yyyy): 08-28-2013

PROJECT DESCRIPTION

Costs **to install:** 33 poles, 29 three phase structures, 43 single phase structures, 11 groundings, 21 anchors, 22 guy wires
to salvage: 6 single phase structures and single phase line.
to string: ~2km of 4x1/0 ACSR, ~ 600m of 2x#4

Load clipping required before and after Hot Springs Rd tap-off before single phase loads can be properly phased.

PROJECT APPROVALS	NAME	SIGNATURES	DATE
ENGINEERING APPROVAL	Phil Borgel		Mar 12/11
MARKETING APPROVAL	Phil Borgel		Mar 12/11
EXPENDITURE APPROVALS			
E & C SUPERINTENDENT			
CLOSEOUT APPROVAL	Phil Borgel		Aug 30/11
Construction Completed by:			MAR 11/11

Lighting up the North

Yukon Electrical
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PROJECT INSPECTION - QUALITY AUDIT - COMMISSIONING FORM

Project #: 711969
Crew Name: AP
Crew Foreman:

Project Description: 3 Mile Hotsprings Rd.
Land Location/Plant #:

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or inspector for 25% of Cat 2, 3, 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
A. POLES													
1. Tamping & Backfill	☑	☐	☐		☐	☐	☐		☑	☐	☐		
2. Straightness of Line	☑	☐	☐		☐	☐	☐		☑	☐	☐		
3. Asset tagged	☑	☐	☐		☐	☐	☐		☑	☐	☐		
4. Setting Depth	☑	☐	☐		☐	☐	☐		☑	☐	☐		
B. FRAMING													
1. As per staking list/construction standard	☑	☐	☐		☐	☐	☐		☑	☐	☐		
2. Bonding as per construction standard	☑	☐	☐		☐	☐	☐		☑	☐	☐		
C. ANCHORING													
1. Pole rake/kick as per const. standard	☑	☐	☐		☐	☐	☐		☑	☐	☐		
2. As per staking list/drawing	☑	☐	☐		☐	☐	☐		☑	☐	☐		
3. Bonding bolts installed	☑	☐	☐		☐	☐	☐		☑	☐	☐		
4. Anchor Depth	☑	☐	☐		☐	☐	☐		☑	☐	☐		
5. Guy guards installed	☑	☐	☐		☐	☐	☐		☑	☐	☐		
6. Guy strains installed	☑	☐	☐		☐	☐	☐		☑	☐	☐		
7. Guys are tight	☑	☐	☐		☐	☐	☐		☑	☐	☐		

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
K. SALVAGE WORK													
1. All material picked up	☑	☐	☐		☐	☐	☐		☑	☐	☐		
2. All wire rolled up	☑	☐	☐		☐	☐	☐		☑	☐	☐		
3. All holes filled in	☑	☐	☐		☐	☐	☐		☑	☐	☐		
4. All anchors, ground rods pole stubs pulled/removed	☑	☐	☐		☐	☐	☐		☑	☐	☐		
5. Site left acceptable & presentable	☑	☐	☐		☐	☐	☐		☑	☐	☐		
6. Third Party Transfer/Poles	☑	☐	☐		☐	☐	☐		☑	☐	☐		
L. PROPERTY DAMAGE													
1. Ruts repaired	☐	☐	☑		☐	☐	☐		☐	☐	☑		
2. Other (fence, crop, trees, etc)	☐	☐	☑		☐	☐	☐		☐	☐	☑		
M. EQUIPMENT													
1. Equal to or greater than 1 MVA Transformer as per (Appendix B)	☐	☐	☑		☐	☐	☐		☐	☐	☑		
2. Regulator	☐	☐	☑		☐	☐	☐		☐	☐	☑		
3. Recloser (OVR, WVE, NOVA)	☑	☐	☑		☐	☐	☐		☑	☐	☐		
4. Capacitor	☐	☐	☑		☐	☐	☐		☐	☐	☑		
N. REPORTS COMPLETED													
1. Service Interruption Report (SIR)	☑	☐	☐		☐	☐	☐		☑	☐	☐		
2. Equipment/Asset Documentation	☑	☐	☐		☐	☐	☐		☑	☐	☐		
3. "As Built" Completed & Signed	☑	☐	☐		☐	☐	☐		☑	☐	☐		

CONSTRUCTION INSPECTION	QUALITY INSPECTION	COMMISSIONING
(To be completed by Lead Lineman/Crew Foreman)	(To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4)	(All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system)

DESCRIPTION	COMPLETED AS PER SCOPE/DESIGN/STANDARD			ACCEPTED			ACCEPTED			DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	

Crew Lead Lineman/Foreman Comments: Ready to Go

Construction Inspection Completed By: [signature] **Date:** MAR 11/11

Construction Lead or Inspector Comments:

Quality Audit Completed By: **Date:**

Commissioning Comments:

Commissioning Completed By: **Date:**

Construction Start Date:

Crew Lead/Foreman: (Who)

Release to Energize Date: MAR 11 / 11

Released By: [signature] (Crew Lead, Foreman or Construction Lead)

Construction Complete & Release to Energize Date: 03/11/2011

Accepted By: E BANKS. (Construction Lead)

Commissioning Accepted Date: Aug 2, 2011

Commissioning Accepted By: D Rusnak (OIC - ONLY)

New Service Connection Information

Customer Name:

Date of Hook up/Connection:

Electrical Permit Received: ☐ Yes ☐ No **Comments:**

Meter Forms Complete ☐ Yes ☐ No **Comments:**

Yukon Electrical
An ATCO Company

Project No.: Y11969.
Project Description:

February 24, 2011 11:24 AM

Click for Program Properties

Revision:
User:

Segment Name	Qty	Structure	#of Cond.	Comments
	0.6	#4SB150	2	
	9	R0		
	1	R109		
	2	R112		
	1	R130		
	2	R140		
	4	R152		
	14	R154		
	9	R71		
	1	R196		
	2.11	#1:0	4	
	2	N11		
	19	N12		
	1	N41		
	6	N50		
	1	N54A		
	10	E12		
	1	E13		
	18	G10		
	2	G40		
	2	G50		
	20	X0A		
	2	X0B		
	21	Anc-E		
	-21	E190137		
	21	E190480		
	21	E190679		
	1	E260073		FUSELINK FIT/TRIP KS 5A
	2	E260075		FUSELINK FIT/TRIP KS 7A
	1	E260080		FUSELINK FIT/TRIP KS 20A
	1	E260065		FUSELINK FIT/TRIP X 1/2A
	1	E260066		FUSELINK FIT/TRIP X 1 A
	3	E260070		FUSELINK FIT/TRIP X 2 1/2A

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION		UNIT PRICE		TOTAL PRICE		BIN #
16		E190054	8311	BOLT EYE 5/8X 8 IN GALV				0.00		B1A004
24		E190055	8311	BOLT EYE 5/8X10 IN GALV				0.00		B1A005
15		E190056	8311	BOLT EYE 5/8X12 IN GALV				0.00		B1A006
14		E190057	8311	BOLT EYE 5/8X14 IN GALV				0.00		B1A007
8		E190059	8311	BOLT EYE 5/8X18 IN GALV				0.00		B1A009
42		E190078	8311	BOLT MACH 1/2X06 IN GALV				0.00		B1B005
16		E190079	8311	BOLT MACH 1/2X07 IN GALV				0.00		B1B006
9		E190094	8311	BOLT MACH 5/8X10 IN GALV				0.00		B1C007
59		E190095	8311	BOLT MACH 5/8X12 IN GALV				0.00		B1C008
65		E190096	8311	BOLT MACH 5/8X14 IN GALV				0.00		B1C009
21		E190097	8311	BOLT MACH 5/8X16 IN GALV				0.00		B1C010
4		E190281	8311	CNTR BAIL 9OD FOR BYPASS SWCH				0.00		B1D002
2		E190109	8311	BOLT MACH 3/4X14 IN GALV				0.00		B1D005
9		E360066	8311	BRKT SWCH MTG ATCO SPEC #10984				0.00		B1E003
23		E190143	8311	CLAMP BAIL 6 TO 1/0				0.00		B1E004
24		E190137	8311	CLAMP BOND POWER/ANC				0.00		B1E006
28		E190168	8311	CLAMP HL SCREW TYPE				0.00		B1E008
105		E190484	8311	CLEVIS FOR PREF DEADEND GRIP				0.00		B1E009

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE		BIN #
3		E190495	8311	CLEVIS SPOOL TYPE DEAD END			0.00		B1E010
11		E190187	8311	CNTR GRD ROD 3/4 IN ROD			0.00		B1E012
2		E190278	8311	CNTR BAR TAP XER/SEC			0.00		B1E013
21		E190201	8311	COUPLING GRD/ROD SPEC 9941			0.00		B1E014
20		E190530	8311	FITTING GUY			0.00		B1E015
77		E260214	8311	INSULATOR FOR 1 IN. PIN 25 KV			0.00		B2A004
29		E260220	8311	INSUL SPOOL SL355			0.00		B2A005
69		E260235	8311	INSUL DE 25 KV POLYMERIC			0.00		B2A007
11		E210047	8311	SHELL AMPACT BLUE 69338-1			0.00		B2A009
31		E190589	8311	PIN PLTP 24" GALV.			0.00		B2A014
11		E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD			0.00		B2B002
70		E190660	8311	TIE TOP DIST "F" 1/0 RAVEN			0.00		B2B002
36		E190620	8311	GRIP DE PREF 5/16 GUY WIRE			0.00		B2B003
63		E190598	8311	GRIP DE PREF 4 ACSR			0.00		B2B005
9		E190658	8311	TIE TOP DIST "F" #4 POLLOCK			0.00		B2B006
2		E190669	8311	TIE SPOOL FOR #4 ACSR POLLOCK			0.00		B2C005
40		E190716	8311	WASHER RD GALV FOR 5/8" BOLT			0.00		B2C007
42		E190600	8311	GRIP DE PREF 1/0 ACSR			0.00		B2D003
60		E190471	8311	NUT PAL 1/2 INCH GALV			0.00		B2D005
209		E190472	8311	NUT PAL 5/8 INCH GALV			0.00		B2D006
277		E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8			0.00		B2D007
6		E190473	8311	NUT PAL 3/4 INCH GALV			0.00		B2D008
2		E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4			0.00		B2D009
62		E190715	8311	WASHER RD GALV FOR 1/2" BOLT			0.00		B2E004
244		E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE			0.00		B2E005
60		E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT			0.00		B2E011
39		E190584	8311	PIN CROSSARM 6" SHANK			0.00		B3A014
4		E190583	8311	PIN CROSSARM ANGLED			0.00		B3A015
4		E300008	8311	SLEEVE AUTO 1/0 ACSR 6/1			0.00		B3C016
55		E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED			0.00		B3C022
6		E190548	8311	STRAP BONDING 9" T-STD-807 A			0.00		B3D006
1		E190508	8311	GAIN POLE GALV 3/4" BOLT			0.00		B3D008
26		E190466	8311	NUT EYE 5/8 IN GALV			0.00		B3D009
21		E190480	8311	NUT EYE 3/4" OR 1" ANC ROD ALL			0.00		B3D011
1		E190533	8311	FITTING LINK SL6784 OR EQUIV.			0.00		B3E009
2		E260075	8311	FUSELINK FIT/TRIP KS 7A			0.00		B5A018
1		E260073	8311	FUSELINK FIT/TRIP KS 5A			0.00		B5A019
1		E260080	8311	FUSELINK FIT/TRIP KS 20A			0.00		B5A024
21		E300074	8311	SLEEVE SQUEEZON BB WR279			0.00		B6A020
32		E300073	8311	SLEEVE SQUEEZON BB WR159			0.00		B6A024
44		E300075	8311	SLEEVE SQUEEZON BB WR189			0.00		B6A026
6		E190712	8311	WASHER LOCK PLATED 1/2"			0.00		LU0001
9		E260306	8311	SWCH DISC 25KV 100A			0.00		QT0000
11		E160078	8311	COND ROUND 3/4 IN PVC			0.00		RA0001
24		E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH			0.00		RA0001
24		E260255	8311	INSUL GUY STRAIN			0.00		RA0001
21		E190679	8311	ROD ANC PWR 3/4 X 7FT			0.00		RA0001
32		E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941			0.00		RA0001
4		E350080	8311	WIRE CU 2/0 STRD WP			0.00		RB0001
21		E350017	8311	WIRE ALUM*TIE 4			0.00		RB0002
201		E350078	8311	WIRE CU 2 STRD WP			0.00		RB0002
15		E350077	8311	WIRE CU 4 STRD WP			0.00		RB0002
1		E190628	8311	ROD ARMOR FOR #4 ACSR POLLOCK			0.00		RB0004
2		E190630	8311	ROD ARMOR FOR 1/0 ACSR RAVEN			0.00		RB0004
12		E190626	8311	GRIP DE PREF 7/16 GUY WIRE			0.00		RC0002
21		E190013	8311	ANC PWR S/HELIX 10IN TOUGH ONE			0.00		RD0001

Parts List

QTY		OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE		BIN #
1		E190476	8311	NUT SQ 5/8 INCH GALV			0.00		RG0002
29		E360029	8311	BRACE ANGLE ARM 42 INCH B.C.			0.00		YA0001
216		E350029	8311	WIRE GUY 5/16 GRADE 180 COILS			0.00		YA0001
110		E350031	8311	WIRE GUY 7/16 GRADE 180 COILS			0.00		YA0002
1218		E350012	8311	WIRE ACSR 4 SB POLLOCK			0.00		YA0003
8566.6		E350001	8311	WIRE ACSR 1/0 6/1 RAVEN			0.00		YA0003
8		E360020	8311	ARM 2P 5X5X7 GLU/LAM ANG/BRACE			0.00		YB0001
21		E360012	8311	ARM 2P GLU/LAM 7FT ANG/BRACE			0.00		YB0001
6		E190461	8311	NUT HEX PLATED 1/2" UNC			0.00		Z00000
2		E190083	8311	BOLT MACH 1/2X14 IN GALV			0.00		#N/A
6		E190025	8311	BOLT PLATED 1/2X1-1/2 GR 5 NC			0.00		#N/A
22		E320050	8311	DISPENSOR GUY WIRE (CAGES)			0.00		#N/A
165		E190897	8311	FENCE STAPLES, HOT DIP GALVANIZED 1 3/4"			0.00		#N/A
3		E190588	8311	PIN PLPT CORNER 24"X 30D ANGLE			0.00		#N/A
0		E300004	8311	SLEEVE AUTO 4 ACSR SB 150% LENGTH 8.5"			0.00		#N/A
0		E260307	8311	SWCH FUSED OCR BYPASS 25KV			0.00		#N/A
0		E260377	8311	VERSA-TECH RECLOSER SINGLE PHASE 27kV, 30A TO 800A FAULT			0.00		#N/A
2		E190698	8311	WASHER CURVED 3 IN 13/16 H			0.00		#N/A
6		E190714	8311	WASHER RD CAD PLTD 1/2" BOLT			0.00		#N/A
21			8311				0.00		#N/A
									#N/A

Total Unloaded Stocked Material Cost $0
Spot Construction Manhours

Total Loaded Stocked Mat Cost(11%) $0

Yukon Electrical
An ATCO Company

STAKING LIST
Revised: Feb. 21, 2011 by DS
CHECK PRINT

Project Number: Y11969 Hotsprings Road 3ph Line
Location: Hotsprings Road to Pilot Mtn Subdivision
Survey Date: Feb. 21, 2011 by Y.E.S.
Loading: Medium

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type										Comments
						Struct 1	Struct 2	Struct 3	Struct 4	Struct 5	Struct 6	Struct 7	Struct 8	Struct 9	Struct 10	
exist				40	obt	N12	R154	N54A								remove 1ph, install long 3ph, #4 slack span - SOLID
2898		15				exist	salvage									do not pull much tension on 4 x 1/0 slack span. Build square corner tap-off. Clip phases & label: Road, Centre, and Bush phase.
24666	1	42.3		55	2	(2)N50	(2)R0	G50	(2)anc-E	E12	E20					See drawing for set up.
24667	2	59.3		45	3	N50	X0A									
24668	3	64.9	12°	45	3	N11	X0B	R154	R71	(2)G10	(2)anc-E	R154 temp				Sw# 3093 fuse: 5A KS See drawing for temp set up.
24669	4	70.5	7°	45	5	N11	X0B	G10	anc-E	E12	E20					
24670	5	75		45	5	N12	X0A									
24671	6	86.7		45	3	N12	X0A	R154	R71	G10	anc-E	R154 temp				Sw# 3094 fuse: 1A X See drawing for temp set up.
24672	7	90.3		40	5	N12	X0A	E12	E20							
24673	8	80.3	9°	40	3	N50	(2)R0	G40	G10	(2)anc-E						add temporary stringing anchor w/ G40
24674	9	80.1		40	3	N50	(2)R0	G40	anc-E							add temporary stringing anchor w/ G40
24675	10	80.1		40	5	N12	X0A	E12	E20							
24676	11	80.1		45	3	N12	X0A	R154	R71	G10	anc-E					Sw# 3095 fuse: 2.5A X add xarm for temp feed, remove on final cut over
24677	12	80.1		45	5	N12	X0A									
24678	13	80.1		40	5	N12	X0A	E12	E20							
24679	14	80.1		40	5	N12	X0A									
24680	15	82.4		45	5	N12	X0A									
24681	16	87.8		45	3	N12	X0A	R154	R71	G10	anc-E	E12	E20			Sw# 3096 fuse: 2.5A X
24682	17	90.1		40	5	N12	X0A									
24683	18	90.1		40	3	N50	(2)R0									
24684	19	90.1		40	5	N12	X0A	E12	E20							
24685	20	90.1		40	5	N12	X0A									
24686	21	90.1		40	5	N12	X0A									
24687	22	90.1		45	3	N12	X0A	R154	R71	E12	E20					Sw# 3097 fuse: 7A KS
24688	23	68.2		40	5	N12	X0A									
24689	24	68.2		40	5	N12	X0A									
24690	25	61.5		45	3	N12	X0A	R154	R71	G10	anc-E	E12	E20			Sw# 3098 fuse: 7A KS add xarm for temp feed, remove on final cut over
24691	26	83.3		50	3	N12	X0A	R154	R71	G10	anc-E					Sw# 3099 fuse: 20A KS
24692	27	9.2		45	3	N41	R0	R154	G50	(2)anc-E						DE 4 x 1/0 acsr here - slack 2 x #4acsr to pole #28

Yukon Electrical
An ATCO Company

STAKING LIST
Revised: Feb. 21, 2011 by DS
CHECK PRINT

Project Number: Y11969 Hotsprings Road 3ph Line
Location: Hotsprings Road to Pilot Mtn Subdivision
Survey Date: Feb. 21, 2011 by Y.E.S.
Loading: Medium

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type										Comments
						Struct 1	Struct 2	Struct 3	Struct 4	Struct 5	Struct 6	Struct 7	Struct 8	Struct 9	Struct 10	
exist 23818	J					As Above										
24697	30	1		40	3	R140	R154	R71	(2)G10	anc-E						Sw# 3101 fuse: 2.5A X set new pole 1m on tap side,use exist conductor
exist 23817	I			35	5 1973	R112 salvage	R154 salvage	R71 salvage	G10 salvage	anc-E exist						salvage pole - reuse exist anchor to be replaced by pole #30
exist 20467	H					As Above										
exist 23816	G			35	5 1973	R122 exist	G10 exist	anc-E exist	G10							add guy wire
exist 23815	F			35	5 1973	R112 exist	R154 exist	R71 exist	G10 exist	anc-E exist						No changes to the pole
exist 23814	E	1		40	5 1973	R110 salvage	R154 salvage	R71 salvage	G10 salvage	anc-E salvage						salvage pole - to be replaced by pole #31
24698	31			40	3	R140	R154	R71	(2)G10	(2)anc-E						Sw# 3102 fuse: 0.5A X set new pole 1m on tap side,use exist conductor

ATCO Electric

DISTRIBUTION DEPARTMENT
PROJECT HEADER REPORT

GENERAL INFORMATION

PROJECT NUMBER	Y12409
PROJECT NAME	
PROJECT DESCRIPTION	
APPROPRIATION	70004
ASSET PLANT	
PROJECT STATUS	A
REGION	
DISTRICT	
SERVICE POINT	Whitehorse
PROJECT LEAD	Brock
PROJECT REQUESTED BY	
CUSTOMER CONTACT	
CUST. CONTACT PHONE	

METERING AND SERVICES

NUMBER OF SERVICES	N/A
METERING STANDARD	
METERING TYPE	
CT RATING	
PT RATING	
FARM BREAKER SIZE	
PHASES	
SECONDARY VOLTS	
CUST. OPER. KVA	
RATE CLASS CODE	
TOTAL TRANSFORMER KVA	

ESTIMATED BURDENED COSTS

EASEMENTS	
SURVEY	
BRUSHING	
MATERIAL	
MATERIAL HANDLING	
CONSTRUCTION LT&E	
PROJECT LT&E	
MISCELLANEOUS CHARGES	
DEMOLITION & SALVAGE	
CAPITAL ADJUSTMENTS	
TOTAL PROJECT ESTIMATE:	

OTHER COSTS (for info only)

SYSTEM COST CONTRIBUTIONS	

PROJECT MILESTONES (DATES)

PROJECT SET-UP	
PROPOSAL REQUESTED	
CUST. REQUESTED ISD	
FIELD CHECK RECEIVED	
ESTIMATE TO MARKETING	
TARGET RELEASE DATE	

Printed (mm-dd-yyyy): 04-13-2012

PROJECT DESCRIPTION

Crestview to Mayo Rd Rebuild

Poles 1-10

Set two 55ft class 2 poles, four 55ft class 3 poles, four 50ft class 3 poles and one 45ft class3 pole
Install 8 anchors, string approx 775m of 4 X #266.8 ACSR and 15m of 2 X #4ACSR
Hang one 10 KVA Xer and a 25 KVA and refeed St Lts and residences

PROJECT APPROVALS	NAME	SIGNATURES	DATE
ESTIMATE APPROVAL			Apr 16/12
ENGINEERING APPROVAL			
MARKETING APPROVAL			Apr 16/12
EXPENDITURE APPROVALS			
SR. ENGINEER			
E & C SUPERINTENDENT			
REGIONAL MANAGER			
VICE-PRESIDENT (DIST.)			
PRESIDENT (ATCO ELEC.)			
CLOSEOUT APPROVAL			
SR. ENGINEER			

Construction TONY BARRY May 7/13

Lighting up the North

Yukon Electrical
An **ATCO** Company

PROJECT INSPECTION - QUALITY AUDIT - COMMISSIONING FORM

Project #: Y12409 **Project Description:**

Crew Name: Arctic Power

Crew Foreman: Rob Wells **Land Location/Plant #:** Alaska Hwy / Crestview

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
A. POLES													
Tamping & Backfill	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. Straightness of Line	☑	☐	☐		☑	☐	☐		☐	☐	☐		
3. Asset tagged	☑	☐	☐		☑	☐	☐		☐	☐	☐		
4. Setting Depth	☑	☐	☐		☑	☐	☐		☐	☐	☐		
B. FRAMING													
1. As per staking list/construction standard	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. Bonding as per construction standard	☑	☐	☐		☑	☐	☐		☐	☐	☐		
C. ANCHORING													
1. Pole rake/kick as per const. standard	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. As per staking list/drawing	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Bonding bolts installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
4. Anchor Depth	☑	☐	☐		☑	☐	☐		☐	☐	☐		
5. Guy guards installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
6. Guy strains installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
7. Guys are tight	☑	☐	☐		☑	☐	☐		☐	☐	☐		

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
D. STRINGING/SAGGING													
1. Lines sag to standard (provide date, loc, sag & temp.)	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. Ties as per standard	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Road/Railway/pipeline/critical water crossings - clearance to design	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Horizontal/Vertical Clearance to other objects	☑	☐	☐		☑	☐	☐		☐	☐	☐		
GROUNDING													
Grounded as per staking list & drawing	☑	☐	☐		☑	☐	☐		☐	☐	☐		
All ground connections completed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Meggered & tagged - SWGR & MGN (provide readings)	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Danger High Voltage sign installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
F. SWITCHES													
1. Fusing/Switches as per design	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. Fuse size tag installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Switch number installed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
Operational SLD Map Updated	☑	☐	☐		☑	☐	☐		☐	☐	☐		
G. TRANSFORMER													
1. All connections completed & correct	☑	☐	☐		☑	☐	☐		☐	☐	☐		
2. All ground connections completed	☑	☐	☐		☑	☐	☐		☐	☐	☐		
3. Oil leaks/bushings inspected	☑	☐	☐		☑	☐	☐		☐	☐	☐		
4. Voltage tested & verified correct	☐	☐	☑		☑	☐	☐		☐	☐	☐		

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2. 3. 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
H. SERVICE CONNECTIONS													
1. All connections completed	☑				☑								
2. Customer grounding connected			X	Not required			X	Not required					
3. Cabinet & breaker connections complete & correct			☑				☑						
I. BRUSHING													
1. Clearance as per brushing standards	☑				☑								
2. Brushing cleaned up adequately	☑				☑								
J. UNDERGROUND EQUIPMENT													
1. Phase schematic, phase tags & switch number installed			☑				☑						
2. Danger High Voltage tags installed							☑						
3. Danger Buried Cable signs installed							☑						
4. Hi Pot readings (What are they?)							☑						
5. Warning signs installed							☑						
6. All secondary connections complete, correct and tagged							☑						
7. Service address tags installed							☑						
8. Locks, penta bolts installed							☑						
9. Trench backfilled to standard/design							☑						
10. Clearance to fence & buildings							☑						
11. First call notification - U/G complete							☑						
12. Equipment to Grade							☑						
13. Equipment Protection Installed							☑						
14. Subdivision commissioning as per Appendix A.							☑						

DESCRIPTION	CONSTRUCTION INSPECTION (To be completed by Lead Lineman/Crew Foreman) COMPLETED AS PER SCOPE/DESIGN/STANDARD				QUALITY INSPECTION (To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4) ACCEPTED				COMMISSIONING (All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system) ACCEPTED				DATE DUE
	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	Yes	No	N/A	Action Required (if no)	
K. SALVAGE WORK													
1. All material picked up	☐	☐	☐		☑	☐	☐		☐	☐	☐		
2. All wire rolled up	☐	☐	☐		☑	☐	☐		☐	☐	☐		
3. All holes filled in	☐	☐	☐		☑	☐	☐		☐	☐	☐		
4. All anchors, ground rods pole stubs pulled/removed	☐	☐	☐		☐	☐	☑		☐	☐	☐		
te left acceptable & presentable	☐	☐	☐		☑	☐	☐		☐	☐	☐		
6. Third Party Transfer/Poles	☐	☐	☐		☐	☐	☐	NWITEL TO TRANSFER @ LATER DATE.	☐	☐	☐		
L. PROPERTY DAMAGE													
1. Ruts repaired	☐	☐	☐		☐	☐	☑		☐	☐	☐		
2. Other (fence, crop, trees, etc)	☐	☐	☐		☐	☐	☑		☐	☐	☐		
M. EQUIPMENT													
1. Equal to or greater than 1 MVA Transformer as per (Appendix B)	☐	☐	☐		☐	☐	☑		☐	☐	☐		
2. Regulator	☐	☐	☐		☐	☐	☑		☐	☐	☐		
3. Recloser (OVR, WVE, NOVA)	☐	☐	☐		☐	☐	☑		☐	☐	☐		
4. Capacitor	☐	☐	☐		☐	☐	☑		☐	☐	☐		
N. REPORTS COMPLETED													
1. Service Interruption Report (SIR)	☐	☐	☐		☑	☐	☐		☐	☐	☐		
2. Equipment/Asset Documentation	☐	☐	☐		☐	☐	☑		☐	☐	☐		
3. "As Built" Completed & Signed	☐	☐	☐		☑	☐	☐		☐	☐	☐		

	CONSTRUCTION INSPECTION			QUALITY INSPECTION			COMMISSIONING			
	(To be completed by Lead Lineman/Crew Foreman)			(To be completed by OIC for all Cat 1 & Const Lead or Inspector for 25% of Cat 2, 3, 4)			(All project Categories must be commissioned by OIC or designate prior to being accepted on or part of the system)			
DESCRIPTION	**COMPLETED AS PER SCOPE/DESIGN/STANDARD**			**ACCEPTED**			**ACCEPTED**			**DATE DUE**
	Yes	No	N/A	Yes	No	N/A	Yes	No	N/A	
	Action Required (if no)			*Action Required (if no)*			*Action Required (if no)*			

Crew Lead Lineman/Foreman Comments:

Construction Inspection Completed By: X _____ **Date:** X _____

Construction Lead or Inspector Comments: Construction Complete. St. Light trenching will be part of a separate W.O. for 2013

Quality Audit Completed By: J Bodey **Date:** May 7/13

Commissioning Comments:

Commissioning Completed By: _____ **Date:** _____

Construction Start Date: X _____

Release to Energize Date: X J. Bodey

Construction Complete & Release to Energize Date: _____

Commissioning Accepted Date: _____

Crew Lead/Foreman: X _____ (Who)

Released By: X J. Bodey (Crew Lead, Foreman or Construction Lead)

Accepted By: _____ (Construction Lead)

Commissioning Accepted By: _____ (OIC - ONLY)

New Service Connection Information

Customer Name: _____

Date of Hook up/Connection: _____

Electrical Permit Received: ☐ Yes ☐ No **Comments:** _____

Meter Forms Complete ☐ Yes ☐ No **Comments:** _____

ATCO Electric

April 16, 2012 7:59 AM

Click for Program Properties

Project No.: Y12409
Project Description: Cerstview to Mayo Rd Preliminary Material List

Revision: 03-02-2012
User: BC

Segment Name	Qty	Structure	#of Cond.	Comments
	0.86	#266.8	4	
	3	ANC-E		
	3	E12		
	6	ANC-T		
	3	G10		
	6	G40		
	9	X12B		
	2	R0		
	9	Y12		
	1	Y42		
	1	N54A		
	1	N82		
	0.05	#4SB150	2	
	2	R154		
	1	R71F		
	1	R152		
	1	R182		
	1	T25-14		
	2	T10-14		
	0.05	#1X6&1X6	2	
	3	X40B		
	3	E190144		CLAMP BAIL 1/0 TO 556
	2	E190143		CLAMP BAIL 6 TO 1/0
	-3	E190055		BOLT EYE 5/8X10 IN GALV
	1	E190066		BOLT EYE SHOULDER 3/4X16 GALV
	-1	E190069		BOLT EYE SHOULDER 3/4X22 GALV
	1	E190070		BOLT EYE SHOULDER 3/4X24 GALV
	17	E190096		BOLT MACH 5/8X14 IN GALV
	-20	E190095		BOLT MACH 5/8X12 IN GALV
	10	E190098		BOLT MACH 5/8X18 IN GALV
	10	E190111		BOLT MACH 3/4X18 IN GALV
	2	E190037		BOLT DA 3/4X26 IN GALV
	10	E190508		GAIN POLE GALV 3/4" BOLT
	2	E190466		NUT EYE 5/8 IN GALV
	5	E190467		NUT EYE 3/4 IN GALV
	20	E350079		WIRE CU 1/0 STRD WP
	3	E190258		CNTR AMP BLUE 602046-3
	3	E210047		SHELL AMPACT BLUE 69338-1
	2	P55-2		
	4	P55-3		
	4	P50-3		
	1	P45-3		
	6	E300075		SLEEVE SQUEEZON BB WR189

Parts List

QTY	OFIN CAT#	WBS #	DESCRIPTION	UNIT PRICE		TOTAL PRICE	BIN#
2	E190054	8311	BOLT EYE 5/8X 8 IN GALV				B1A004
3	E190056	8311	BOLT EYE 5/8X12 IN GALV				B1A006
2	E190057	8311	BOLT EYE 5/8X14 IN GALV				B1A007
1	E190059	8311	BOLT EYE 5/8X18 IN GALV				B1A009
2	E190078	8311	BOLT MACH 1/2X06 IN GALV				B1B005
24	E190079	8311	BOLT MACH 1/2X07 IN GALV				B1B006
1	E190066	8311	BOLT EYE SHOULDER 3/4X16 GALV				B1B010
1	E190070	8311	BOLT EYE SHOULDER 3/4X24 GALV				B1B014
1	E190094	8311	BOLT MACH 5/8X10 IN GALV				B1C007

6	E190095	8311	BOLT MACH 5/8X12 IN GALV				B1C008
29	E190096	8311	BOLT MACH 5/8X14 IN GALV				B1C009
1	E190097	8311	BOLT MACH 5/8X16 IN GALV				B1C010
10	E190098	8311	BOLT MACH 5/8X18 IN GALV				B1C011
2	E190108	8311	BOLT MACH 3/4X12 IN GALV				B1D004
6	E190109	8311	BOLT MACH 3/4X14 IN GALV				B1D005
11	E190110	8311	BOLT MACH 3/4X16 IN GALV				B1D006
10	E190111	8311	BOLT MACH 3/4X18 IN GALV				B1D007
1	E360066	8311	BRKT SWCH MTG ATCO SPEC #10984				B1E003
9	E190143	8311	CLAMP BAIL 6 TO 1/0				B1E004
3	E190144	8311	CLAMP BAIL 1/0 TO 556				B1E005
9	E190137	8311	CLAMP BOND POWER/ANC				B1E006
10	E190168	8311	CLAMP HL SCREW TYPE				B1E008
16	E190484	8311	CLEVIS FOR PREF DEADEND GRIP				B1E009
12	E190495	8311	CLEVIS SPOOL TYPE DEAD END				B1E010
4	E210054	8311	COVER INSULATOR RODENT PROTECT				B1E011
3	E190187	8311	CNTR GRD ROD 3/4 IN ROD				B1E012
2	E190278	8311	CNTR BAR TAP XER/SEC				B1E013
6	E190201	8311	COUPLING GRD/ROD SPEC 9941				B1E014
9	E190530	8311	FITTING GUY				B1E015
2	E260214	8311	INSULATOR FOR 1 IN. PIN 25 KV				B2A004
22	E260220	8311	INSUL SPOOL SL355				B2A005
7	E260235	8311	INSUL DE 25 KV POLYMERIC				B2A007
3	E260236	8311	INSUL DE 35 KV POLYMERIC				B2A008
21	E210047	8311	SHELL AMPACT BLUE 69338-1				B2A009
1	E190589	8311	PIN PLTP 24" GALV.				B2A014
9	E190590	8311	PIN PLTP SL3049				B2A015
3	E290065	8311	SIGN "DANGER H/VLTAGE" XER GRD				B2B002
6	E190620	8311	GRIP DE PREF 5/16 GUY WIRE				B2B003
8	E190598	8311	GRIP DE PREF 4 ACSR				B2B005
2	E190658	8311	TIE TOP DIST "F" #4 POLLOCK				B2B006
1	E190662	8311	TIE TOP DIST "F" 266 PARTRIDGE				B2C002
12	E190716	8311	WASHER RD GALV FOR 5/8" BOLT				B2C007
26	E190471	8311	NUT PAL 1/2 INCH GALV				B2D005
54	E190472	8311	NUT PAL 5/8 INCH GALV				B2D006
53	E190727	8311	WASHER SPRING DOUBLE/HELIX 5/8				B2D007
38	E190473	8311	NUT PAL 3/4 INCH GALV				B2D008
38	E190728	8311	WASHER SPRING DOUBLE/HELIX 3/4				B2D009
12	E190263	8311	CNTR AMP BLUE 602046-9				B2D012
26	E190715	8311	WASHER RD GALV FOR 1/2" BOLT				B2E004
65	E190729	8311	WASHER SQ 21/4X21/4X11/16 HOLE				B2E005
70	E190730	8311	WASHER SQ 3X3X13/16 HOLE				B2E006
26	E190706	8311	WASHER LOCK GALV FOR 1/2" BOLT				B2E011
3	E190258	8311	CNTR AMP BLUE 602046-3				B3A007
1	E190584	8311	PIN CROSSARM 6" SHANK				B3A014
18	E190586	8311	PIN XARM SL 5728				B3A017
3	E190597	8311	GRIP DE PREF 6 ACSR				B3C003
0	E300010	8311	SLEEVE AUTO*266.8/296 ACSR				B3C012
15	E190693	8311	STAPLE 1 1/16" X 3" GALVANIZED				B3C022
1	E190596	8311	PIN TRANSFORMER				B3C024
1	E190548	8311	STRAP BONDING 9" T-STD-807 A				B3D006
21	E190508	8311	GAIN POLE GALV 3/4" BOLT				B3D008
6	E190466	8311	NUT EYE 5/8 IN GALV				B3D009
5	E190467	8311	NUT EYE 3/4 IN GALV				B3D010
3	E190480	8311	NUT EYE 3/4" OR 1" ANC ROD ALL				B3D011

2	E190037	8311	BOLT DA 3/4X26 IN GALV				B3D016
2	E190030	8311	BOLT DA 5/8X24 IN GALV				B3E021
14	E300073	8311	SLEEVE SQUEEZON BB WR159				B6A024
12	E300075	8311	SLEEVE SQUEEZON BB WR189				B6A026
5	E260306	8311	SWCH DISC 25KV 100A				QT0000
3	E160078	8311	COND ROUND 3/4 IN PVC				RA0001
6	E190677	8311	ROD ANC 1 X 10 GALV				RA0001
9	E190687	8311	ROD GRD 3/4X 6 SECT ATCO#9941				RA0001
9	E210000	8311	GUARD GUY POLY 2.1M C/W ATTACH				RA0001
9	E260255	8311	INSUL GUY STRAIN				RA0001
11	E350017	8311	WIRE ALUM*TIE 4				RB0002
5	E350077	8311	WIRE CU 4 STRD WP				RB0002
57	E350078	8311	WIRE CU 2 STRD WP				RB0002
20	E350079	8311	WIRE CU 1/0 STRD WP				RB0002
101.5	E120027	8311	CABLE DUP 1X 6AL& 1X 6 ACSR				RC0001
12	E190626	8311	GRIP DE PREF 7/16 GUY WIRE				RC0002
3	E190013	8311	ANC PWR S/HELIX 10IN TOUGH ONE				RD0001
27	E260216	8311	INSUL CP 4575				RF0001
4	E260003	8311	ARRSTR 25KV HD DIST POLYMER				RF0004
1	E190476	8311	NUT SQ 5/8 INCH GALV				RG0002
6	E190000	8311	ANCHOR XPLATE 24 IN				YA0001
36	E350029	8311	WIRE GUY 5/16 GRADE 180 COILS				YA0001
2	E360029	8311	BRACE ANGLE ARM 42 INCH B.C.				YA0001
11	E360031	8311	BRACE V ANG ARM 60 IN				YA0001
1	E360068	8311	BRKT TRANS 3 WAY CLUSTER MOUNT				YA0001
90	E350031	8311	WIRE GUY 7/16 GRADE 180 COILS				YA0002
3491.6	E350004	8311	WIRE ACSR 266MCM PARTRIDGE				YA0003
101.5	E350012	8311	WIRE ACSR 4 SB POLLOCK				YA0003
4	E350083	8311	WIRE CU 350MCM SOFT STRD WP				YA0006
1	E360080	8311	POLE 45 FT CLASS 3				YA0019
2	E360089	8311	POLE 55 FT CLASS 2				YA0022
4	E360090	8311	POLE 55 FT CLASS 3				YA0022
1	E360015	8311	ARM 2P 4X5X8 GLU/LAM SLACKSPAN				YB0001
11	E360018	8311	ARM 2P 5 X6X 8 FT GLU-LAM				YB0001
1	E360020	8311	ARM 2P 5X5X7 GLU/LAM ANG/BRACE				YB0001
2	E340084	8332	TKVA 10 OH 24.9GY/14.4/120/240(ATCO SPEC.#95A0228)				YB0003
1	E340102	8332	TKVA 25 OH 24.9GY/14.4/120/240				YB0003
4	E360085	8311	POLE 50 FT CLASS 3				YB0021
	999940	8311	SEC JUMPER WIRE (see H11)				
	999951	8311	SWITCH NUMBER (from ENG)				
27	999999	8311	TIE DISTRIBUTION FOR 34 KV				
3	E190681	8311	ROD ANC PWR 1X 7FT				
6	E190698	8311	WASHER CURVED 3 IN 13/16 H				
45	E190897	8311	FENCE STAPLES, HOT DIP GALVANIZED 1 3/4"				
8	E190907	8311	WEDGE DEAD END SIDE OPENING FOR 266 TO 477 ACSR				
1	E260208	8311	BLADE ASSY FOR 25KV 100AMP DISC SWCH				
	E290041	8311	TAG ASSET STRUCTURE ID ALUM.				
0	E300004	8311	SLEEVE AUTO 4 ACSR SB 150% LENGTH 8.5"				
	E320050	8311	DISPENSOR GUY WIRE (CAGES)				

Spot Construction Manhours

84.6

Yukon Electrical
An ATCO Company

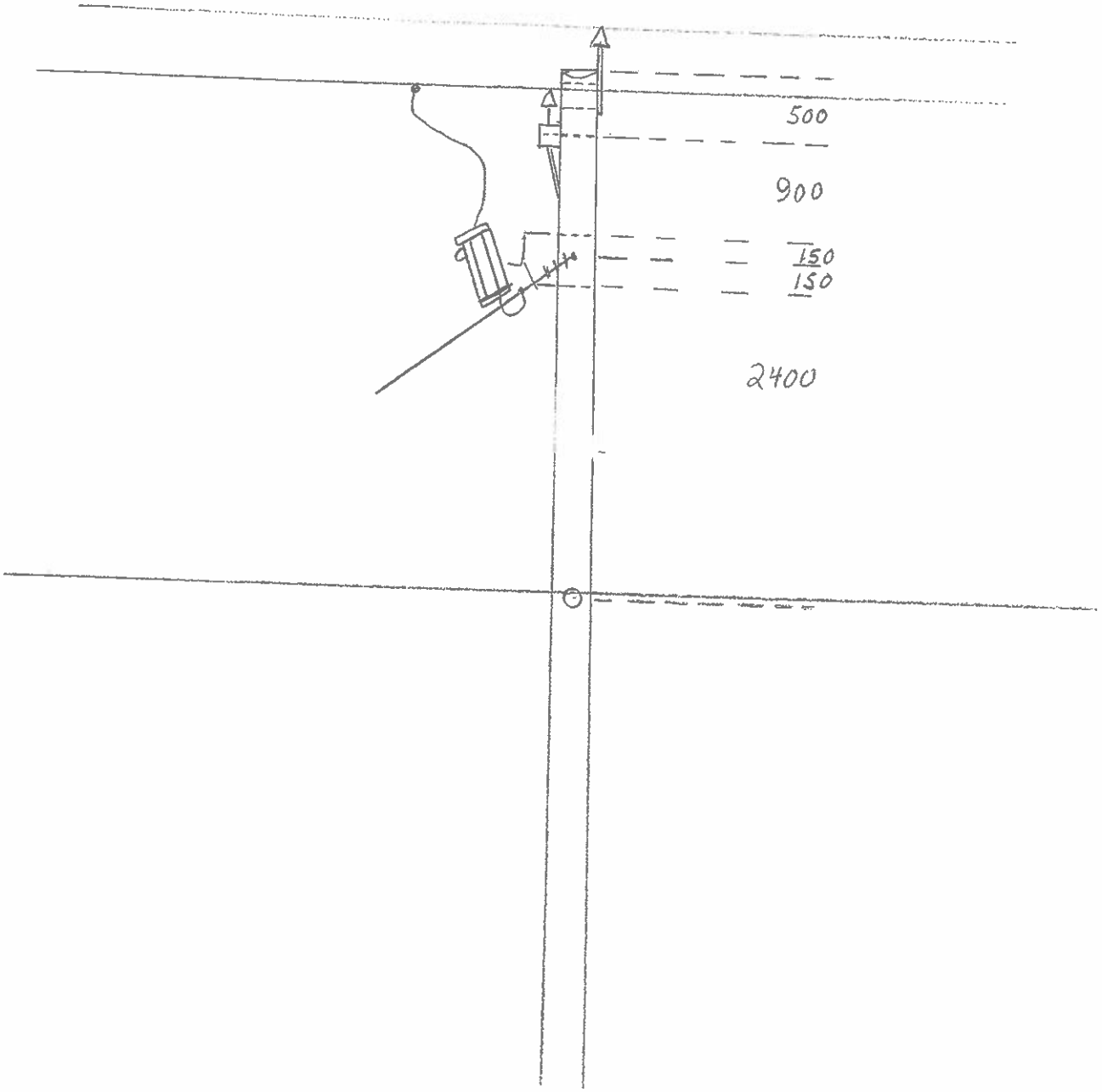
STAKING LIST
Revised: August 11, 2012
CHECK PRINT

Project Number: Y12409 Crestview to Mayo Road Project
Location: Stage 1 Pole #1 to Pole #10
Survey Date: April 5, 2012 by Y.E.S. Eng.

Medium Loading

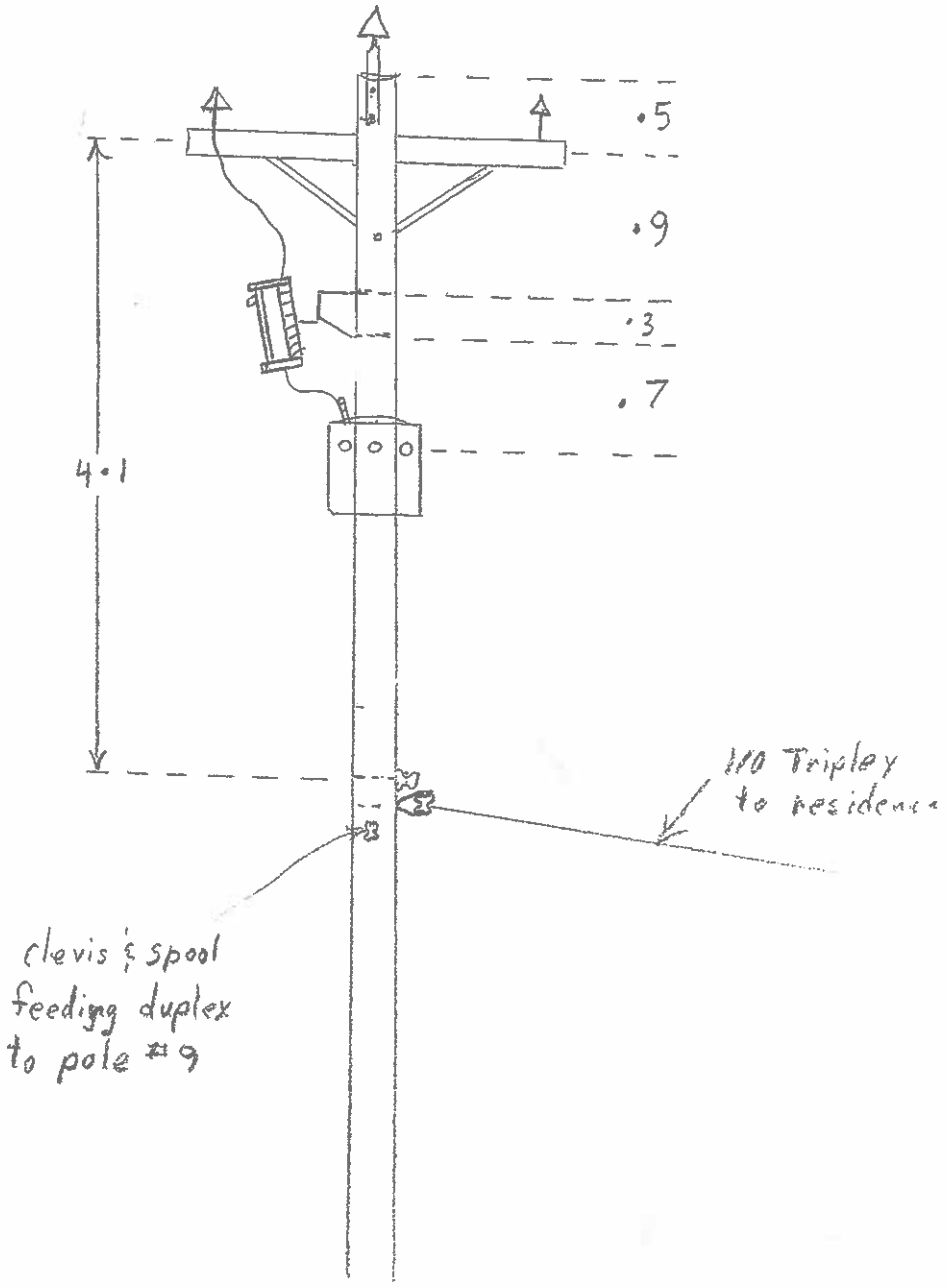
YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type										Comments
						Struct 1	Struct 2	Struct 3	Struct 4	Struct 5	Struct 6	Struct 7	Struct 8	Struct 9	Struct 10	
exist			0°	45	2	Change N42 to N52										string 4 x 266kcmil, top Xarm .5m from top of pole nuetral spacing @ 2.7m from top Xarm unless
26552	1	83		55	3	Y12	X12B	Tangent								otherwise note
26553	2	84		50	3	Y12	X12B	Tangent								Poles 5, 9 & 10 neutral at 3.6m from top Xarm Pole 8 neutral at 4.1 below top Xarm
26554	3	84		50	3	Y12	X12B	E12 Tangent	E20							Pole 5A neutral at 2.1m below primary eye bolt
26555	4	83		50	3	Y12	X12B	Tangent								
26556	5	84		55	3	Y12	X12B	(2)R154	R71	(2)X40B	X405					Temp O/H St Lt feed to pole 23996 til U/G is done Switch # S3485 Fuse 10A Neutral at 3.6 from Xarm
26557	6	91		50	3	Y12	X12B	Tangent								
26558	7	87		55	3	Y12	X12B	Tangent								
26559	8	90		55	3	Y12	R182	E12	E20	(2)G10	(2)anc-E	(2)X40B	X405			Temp O/H St Lt feed to pole 23999 until U/G is done Switch S2764 Fuse 2.5A Neutral at 4.1m from Xarm
26560	9	76		55	2	Y12	N54	X12B	R0	(3)G40	(3)anc-T	(2)X40B				6m anchor for slack span toward Hwy (to pole 11) main anchors at 7 and 8.5m (for future 25KV)
26561 24985	10	10		55	2	Y42	R0	(3)G40	(3)anc-T							Anchoring at 8.5m, 10m & 11.5m
26556	5				SEE	ABOVE										
26562	5A			45	3	R152	R182	G10	ANC-E	E12	E20	X40B				install 10 KVA St Lt Xer Neutral 2.1m Switch S3487 Fuse 1A

Pole #5



Apr 16/12

Pole #8



Apr 16/12

Yukon Electrical
An ATCO Company

STAKING LIST

Revised: August 11, 2012
CHECK PRINT

Project Number: Y12409 Crestview to Mayo Road Project
Location: Stage 1 Pole #1 to Pole #10
Survey Date: April 5, 2012 by Y.E.S. Eng.

Medium Loading

YECL Number	Stake Number	Span Length	Defl.	Pole Size	Pole Class	Structure Type										Comments
						Struct 1	Struct 2	Struct 3	Struct 4	Struct 5	Struct 6	Struct 7	Struct 8	Struct 9	Struct 10	
exist			0°	45	2	Change N42 to N52										string 4 x 266kcmil, top Xarm .5m from top of pole
																nuetral spacing @ 2.7m from top Xarm unless
26552	1	83		55	3	Y12	X12B									otherwise note
26553	2	84		50	3	Y12	X12B									Poles 5, 9 & 10 neutral at 3.6m from top Xarm
																Pole 8 neutral at 4.1 below top Xarm
26554	3	84		50	3	Y12	X12B	E12	E20							Pole 5A neutral at 2.1m below primary eye bolt
26555	4	83		50	3	Y12	X12B									
26556	5	84		55	3	Y12	X12B	(2)R154	R71	(2)X40B	X405					Temp O/H St Lt feed to pole 23996 til U/G is done
																Switch # S3485 Fuse 10A Neutral at 3.6 from Xarm
26557	6	91		50	3	Y12	X12B									
26558	7	87		55	3	Y12	X12B									
26559	8	90		55	3	Y12	R182	E12	E20	(2)G10	(2)anc-E	(2)X40B	X405			Temp O/H St Lt feed to pole 23999 until U/G is done
																Switch S2764 Fuse 2.5A Neutral at 4.1m from Xarm
26560	9	76		55	2	Y12	N54	X12B	R0	(3)G40	(3)anc-T	(2)X40B				6m anchor for slack span toward Hwy (to pole 11)
																main anchors at 7 and 8.5m (for future 25KV)
26561	10	10		55	2	Y42	R0	(3)G40	(3)anc-T							Anchoring at 8.5m, 10m & 11.5m
26556	5				SEE	ABOVE										
26562	5A			45	3	R152	R182	G10	ANC-E	E12	E20	X40B				install 10 KVA St Lt Xer
																Switch S3487 Fuse 1A

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF December 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
GENERATION						
HYDRO GENERATION (LIFE SPAN OF 2052)						
422.00	HYDRO STRUCTURES	72-R2	215,286	59,965	4,724	2.19
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103-R3	1,875,073	316,708	39,536	2.11
425.00	HYDRO GENERATORS	85-R3	1,458,435	153,398	33,511	2.30
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45-R3	105,192	48,486	2,443	2.32
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30-R2	68,657	19,466	2,643	3.85
TOTAL HYDRO PLANT			**3,722,643**	**598,025**	**82,856**	
DIESEL GENERATION						
BEAVER CREEK (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	37,488	22,252	902	2.41
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	92,859	40,692	2,719	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	535,779	367,441	19,646	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	173,365	57,897	5,302	3.06
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	48,603	8,191	1,388	2.86
TOTAL BEAVER CREEK			**888,094**	**496,472**	**29,957**	
CARMACKS (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	167,739	44,228	4,784	2.85
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	40,394	25,071	1,163	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	419,543	309,237	14,948	3.56
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	101,158	34,682	3,102	3.07
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	7,366	535	221	3.00
TOTAL CARMACKS			**736,201**	**413,753**	**24,217**	
DESTRUCTION BAY (LIFE SPAN OF 2023)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	42,282	31,221	1,178	2.79
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	105,478	54,551	4,473	4.24
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	488,076	140,036	31,506	6.46
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	284,627	142,466	12,854	4.52
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	28,048	13,174	1,306	4.66
TOTAL DESTRUCTION BAY			**948,512**	**381,448**	**51,317**	
HAINES JUNCTION (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	608,472	115,568	18,129	2.98
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	619,132	248,915	18,389	2.97
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	60,097	37,282	2,307	3.84
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	94,952	47,493	2,677	2.82
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	2,454	1,482	58	2.36
TOTAL HAINES JUNCTION			**1,385,107**	**450,740**	**41,561**	
OLD CROW (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	187,900	101,997	4,652	2.48
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	215,087	82,975	6,303	2.93
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	1,223,713	529,491	49,686	4.06
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	119,365	68,323	3,379	2.83
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	171,496	66,532	4,561	2.66
TOTAL OLD CROW			**1,917,561**	**849,318**	**68,581**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF December 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
PELLY CROSSING (LIFE SPAN OF 2033)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	48,892	33,820	1,158	2.37
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	129,302	92,887	3,533	2.73
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	474,056	300,758	17,945	3.79
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	431,735	164,126	15,056	3.49
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	61,485	20,121	2,170	3.53
TOTAL PELLY CROSSING			**1,145,469**	**611,712**	**39,862**	
ROSS RIVER (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	171,221	57,383	4,713	2.75
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	85,126	32,959	2,547	2.99
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	189,753	147,095	6,507	3.43
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	124,872	48,576	3,768	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	9,639	1,775	273	2.83
TOTAL ROSS RIVER			**580,611**	**287,788**	**17,808**	
STEWART CROSSING (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	247,966	64,265	7,068	2.85
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	65,107	14,928	1,947	2.99
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	45,677	24,846	1,675	3.67
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	70,425	26,610	2,126	3.02
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	84,682	6,985	2,533	2.99
TOTAL STEWART CROSSING			**513,857**	**137,634**	**15,348**	
SWIFT RIVER (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	22,503	9,907	583	2.59
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	63,430	37,645	1,828	2.88
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	241,047	98,815	9,675	4.01
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	93,560	31,055	2,880	3.08
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	11,924	3,190	328	2.75
TOTAL SWIFT RIVER			**432,465**	**180,612**	**15,295**	
TESLIN (LIFE SPAN OF 2053)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	37,986	10,437	1,133	2.98
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	99,863	22,619	3,016	3.02
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	762,034	524,432	28,347	3.72
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	54,417	25,006	1,611	2.96
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	69,778	9,302	2,014	2.89
TOTAL TESLIN			**1,024,077**	**591,796**	**36,121**	
WATSON LAKE (LIFE SPAN OF 2113)						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	359,393	203,938	8,843	2.46
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	747,818	108,117	22,509	3.01
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	2,169,195	1,318,706	79,932	3.68
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	578,189	305,256	16,449	2.84
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	258,430	61,919	7,095	2.75
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**134,828**	
TOTAL DIESEL PLANT			**13,684,978**	**6,399,211**	**474,894**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF December 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(3)
MOBILE						
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	10,662	8,809	217	2.04
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	25,562	16,999	723	2.83
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	568,500	303,283	21,486	3.78
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	87,652	40,799	2,555	2.91
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	92,170	12,008	2,603	2.82
TOTAL MOBILE			**784,546**	**381,898**	**27,585**	
TOTAL GENERATION			**18,192,167**	**7,379,133**	**585,335**	
SUBSTATION PLANT						
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50-R4	1,384,421	626,639	28,478	2.06
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**28,478**	
DISTRIBUTION PLANT						
471.00	LAND RIGHTS	75-R3	1,267,608	151,638	19,155	1.51
473.00	POLES, TOWERS AND FIXTURES	45-R3	30,231,546	8,972,741	726,834	2.40
474.00	OVERHEAD CONDUCTOR	45-R4	20,514,612	5,832,601	475,347	2.32
474.10	OVERHEAD SERVICES	45-R3	2,849,453	1,023,337	67,049	2.35
475.00	UNDERGROUND CONDUIT	45-R3	20,982,589	6,074,457	506,341	2.41
475.10	UNDERGROUND SERVICES	40-R4	2,953,077	924,039	77,204	2.61
476.10	METERS	15-L0	1,683,985	682,328	134,650	8.00
476.30	AMR - METERS	15-R2.5	67,646	14,259	5,175	7.65
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	3,131,073	1,605,098	79,061	2.53
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	9,147,522	3,814,663	316,295	3.46
478.20	SENTINEL LIGHTS	23-R2	284,738	246,947	8,784	3.08
479.10	LINE TRANSFORMERS	45-R3	24,427,769	6,695,953	590,016	2.42
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**3,005,911**	
GENERAL PLANT						
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	3,459,315	1,660,879	91,701	2.65
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	172,793	62,511	10,448	6.05
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	47,367	10,448	8,929	18.85
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	2,561,147	964,510	157,467	6.15
485.00	TOOLS AND INSTRUMENTS	15-SQ	719,184	273,558	46,712	6.50
486.00	COMMUNICATION EQUIPMENT	15-SQ	872,842	422,551	49,726	5.70
488.20	HOUSES	40-R3	473,256	152,396	12,719	2.69
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**377,702**	
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,590,686**	**3,997,427**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
GENERATION							
HYDRO PLANT (LIFE SPAN OF 2052)							
422.00	HYDRO STRUCTURES	72-R2	(10)	215,286	5,997	472	0.22
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103-R3	(10)	1,875,073	31,671	3,954	0.21
425.00	HYDRO GENERATORS	85-R3	(10)	1,458,435	15,340	3,351	0.23
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45-R3	(10)	105,192	4,849	244	0.23
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30-R2	(10)	68,657	1,947	264	0.38
TOTAL HYDRO PLANT				**3,722,643**	**59,802**	**8,286**	
PRODUCTION DIESEL PLANT							
BEAVER CREEK (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	37,488	2,225	90	0.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	92,859	8,138	544	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	535,779	36,744	1,965	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	173,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	48,603	-	-	-
TOTAL BEAVER CREEK				**888,094**	**47,108**	**2,599**	
CARMACKS (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	167,739	4,423	478	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	40,394	5,014	233	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	419,543	30,924	1,495	0.36
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	101,158	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	7,366	-	-	-
TOTAL CARMACKS				**736,201**	**40,361**	**2,206**	
DESTRUCTION BAY (LIFE SPAN OF 2023)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	42,282	3,122	118	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	105,478	10,910	895	0.85
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	488,076	14,004	3,151	0.65
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	284,627	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	28,048	-	-	-
TOTAL DESTRUCTION BAY				**948,512**	**28,036**	**4,163**	
HAINES JUNCTION (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	608,472	11,557	1,813	0.30
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	619,132	49,783	3,678	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	60,097	3,728	231	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	94,952	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	2,454	-	-	-
TOTAL HAINES JUNCTION				**1,385,107**	**65,068**	**5,721**	
OLD CROW (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	187,900	10,200	465	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	215,087	16,595	1,261	0.59
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	1,223,713	52,949	4,969	0.41
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	119,365	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	171,496	-	-	-

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
TOTAL OLD CROW				**1,917,561**	**79,744**	**6,694**	
PELLY CROSSING (LIFE SPAN OF 2033)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	48,892	3,382	116	0.24
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	129,302	18,577	707	0.55
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	474,056	30,076	1,794	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	431,735	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	61,485	-	-	-
TOTAL PELLY CROSSING				**1,145,469**	**52,035**	**2,617**	
ROSS RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	171,221	5,738	471	0.28
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	85,126	6,592	509	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	189,753	14,710	651	0.34
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	124,872	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	9,639	-	-	-
TOTAL ROSS RIVER				**580,611**	**27,040**	**1,631**	
STEWART CROSSING (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	247,966	6,427	707	0.29
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	65,107	2,986	389	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	45,677	2,485	167	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	70,425	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	84,682	-	-	-
TOTAL STEWART CROSSING				**513,857**	**11,897**	**1,264**	
SWIFT RIVER (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	22,503	991	58	0.26
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	63,430	7,529	366	0.58
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	241,047	9,881	968	0.40
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	93,560	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	11,924	-	-	-
TOTAL SWIFT RIVER				**432,465**	**18,401**	**1,391**	
TESLIN (LIFE SPAN OF 2053)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	37,986	1,044	113	0.30
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	99,863	4,524	603	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	762,034	52,443	2,835	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	54,417	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	69,778	-	-	-
TOTAL TESLIN				**1,024,077**	**58,011**	**3,551**	
WATSON LAKE (LIFE SPAN OF 2113)							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	359,393	20,394	884	0.25
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	747,818	21,623	4,502	0.60
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	2,169,195	131,871	7,993	0.37
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	578,189	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	258,430	-	-	-
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**13,379**	
TOTAL DIESEL PLANT				**13,684,978**	**601,587**	**45,217**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 1B. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO RECOVERY OF THE REQUIRED NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(4)
MOBILE							
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	10,662	881	22	0.20
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	25,562	3,400	145	0.57
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	568,500	30,328	2,149	0.38
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	87,652	-	-	-
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	92,170	-	-	-
TOTAL MOBILE				**784,546**	**34,609**	**2,315**	
TOTAL GENERATION				**18,192,167**	**695,999**	**55,818**	
SUBSTATION PLANT							
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50-R4	(10)	1,384,421	62,664	2,848	0.21
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**2,848**	
DISTRIBUTION PLANT							
471.00	LAND RIGHTS	75-R3	0	1,267,608	-	-	-
473.00	POLES, TOWERS AND FIXTURES	45-R3	(75)	30,231,546	6,729,555	545,126	1.80
474.00	OVERHEAD CONDUCTOR	45-R4	(80)	20,514,612	4,666,080	380,278	1.85
474.10	OVERHEAD SERVICES	45-R3	(10)	2,849,453	102,334	6,705	0.24
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	3,037,229	253,171	1.21
475.10	UNDERGROUND SERVICES	40-R4	(10)	2,953,077	92,404	7,720	0.26
476.10	METERS	15-L0	0	1,683,985	-	-	-
476.30	AMR - METERS	15-R2.5	0	67,646	-	-	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	(10)	3,131,073	160,510	7,906	0.25
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	(10)	9,147,522	381,466	31,629	0.35
478.20	SENTINEL LIGHTS	23-R2	0	284,738	-	-	-
479.10	LINE TRANSFORMERS	45-R3	(10)	24,427,769	669,595	59,002	0.24
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**1,291,536**	
GENERAL PLANT							
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	0	3,459,315	-	-	-
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	172,793	-	-	-
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	0	47,367	-	-	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	25	2,561,147	-	-	-
485.00	TOOLS AND INSTRUMENTS	15-SQ	0	719,184	-	-	-
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	-	-	-
488.20	HOUSES	40-R3	(10)	473,256	15,240	1,272	0.27
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**1,272**	
TOTAL UTILITY PLANT IN SERVICE				**145,424,111**	**16,613,076**	**1,351,474**	

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION								
HYDRO PLANT (LIFE SPAN OF 2052)								
422.00	HYDRO STRUCTURES	ND	215,286	59,965	123,192	(63,227)	37.8	(1,673)
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	1,875,073	316,708	662,044	(345,336)	40.4	(8,548)
425.00	HYDRO GENERATORS	103-R3	1,458,435	153,398	315,135	(161,737)	40.2	(4,023)
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	105,192	48,486	99,610	(51,124)	32.2	(1,588)
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	68,657	19,466	39,992	(20,526)	27.4	(749)
TOTAL HYDRO PLANT			**3,722,643**	**598,025**	**1,239,974**	**(641,949)**		**(16,581)**
PRODUCTION DIESEL PLANT								
BEAVER CREEK (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	37,488	22,252	26,440	(4,188)	18.9	(222)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	92,859	40,692	50,013	(9,322)	22.0	(424)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	535,779	367,441	350,423	17,018	9.6	1,773
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	173,365	57,897	68,793	(10,896)	25.9	(421)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	48,603	8,191	10,719	(2,528)	33.4	(76)
TOTAL BEAVER CREEK			**888,094**	**496,472**	**506,387**	**(9,915)**		**631**
CARMACKS (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	167,739	44,228	52,552	(8,324)	30.2	(276)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	40,394	25,071	30,815	(5,744)	14.4	(399)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	419,543	309,237	294,915	14,323	8.3	1,726
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	101,158	34,682	40,647	(5,965)	24.6	(242)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	7,366	535	212	323	36.0	9
TOTAL CARMACKS		40-R3	**736,201**	**413,753**	**419,141**	**(5,388)**		**818**
DESTRUCTION BAY (LIFE SPAN OF 2023)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	42,282	31,221	37,097	(5,876)	9.5	(619)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	105,478	54,551	67,047	(12,497)	11.6	(1,077)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	488,076	140,036	133,550	6,486	11.0	590
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	284,627	142,466	174,086	(31,620)	11.5	(2,750)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	28,048	13,174	18,011	(4,837)	11.8	(410)
TOTAL DESTRUCTION BAY			**948,512**	**381,448**	**429,792**	**(48,344)**		**(4,266)**
HAINES JUNCTION (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	608,472	115,568	137,319	(21,751)	32.1	(678)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	619,132	248,915	305,938	(57,023)	21.9	(2,604)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	60,097	37,282	35,555	1,727	11.2	154
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	94,952	47,493	58,093	(10,600)	25.4	(417)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	2,454	1,482	1,989	(507)	33.4	(15)
TOTAL HAINES JUNCTION			**1,385,107**	**450,740**	**538,894**	**(88,154)**		**(3,560)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
OLD CROW (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	187,900	101,997	121,194	(19,196)	20.9	(918)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	215,087	82,975	101,983	(19,008)	24.1	(789)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	1,223,713	529,491	505,966	23,525	15.7	1,498
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	119,365	68,323	80,570	(12,247)	18.9	(648)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	171,496	66,532	91,261	(24,729)	26.9	(919)
TOTAL OLD CROW			**1,917,561**	**849,318**	**900,974**	**(51,656)**		**(1,776)**
PELLY CROSSING (LIFE SPAN OF 2033)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	48,892	33,820	40,186	(6,366)	14.0	(455)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	129,302	92,887	114,166	(21,279)	16.3	(1,305)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	474,056	300,758	286,219	14,539	10.6	1,372
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	431,735	164,126	199,681	(35,555)	19.2	(1,852)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	61,485	20,121	27,361	(7,240)	20.5	(353)
TOTAL PELLY CROSSING			**1,145,469**	**611,712**	**667,613**	**(55,901)**		**(2,594)**
ROSS RIVER (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	171,221	57,383	68,182	(10,800)	28.0	(386)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	85,126	32,959	40,510	(7,551)	22.2	(340)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	189,753	147,095	140,282	6,813	7.3	933
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	124,872	48,576	58,732	(10,156)	23.5	(432)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	9,639	1,775	2,208	(433)	33.9	(13)
TOTAL ROSS RIVER			**580,611**	**287,788**	**309,914**	**(22,126)**		**(237)**
STEWART CROSSING (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	247,966	64,265	76,361	(12,096)	30.3	(399)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	65,107	14,928	18,103	(3,176)	28.5	(111)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	45,677	24,846	21,626	3,220	10.9	295
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	70,425	26,610	32,538	(5,928)	24.9	(238)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	84,682	6,985	9,638	(2,653)	35.4	(75)
TOTAL STEWART CROSSING			**513,857**	**137,634**	**158,267**	**(20,633)**		**(528)**
SWIFT RIVER (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	22,503	9,907	11,772	(1,865)	24.9	(75)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	63,430	37,645	46,269	(8,624)	15.7	(549)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	241,047	98,815	94,569	4,245	16.3	260
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	93,560	31,055	37,516	(6,461)	25.0	(258)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	11,924	3,190	4,249	(1,059)	30.6	(35)
TOTAL SWIFT RIVER			**432,465**	**180,612**	**194,375**	**(13,764)**		**(657)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
TESLIN (LIFE SPAN OF 2053)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	37,986	10,437	12,402	(1,964)	28.9	(68)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	99,863	22,619	27,801	(5,181)	27.5	(188)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	762,034	524,432	500,142	24,290	9.6	2,530
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	54,417	25,006	27,410	(2,404)	21.5	(112)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	69,778	9,302	11,989	(2,687)	33.9	(79)
TOTAL TESLIN			**1,024,077**	**591,796**	**579,744**	**12,052**		**2,083**
WATSON LAKE (LIFE SPAN OF 2113)								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	359,393	203,938	242,320	(38,382)	20.1	(1,910)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	747,818	108,117	132,885	(24,768)	30.6	(809)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	2,169,195	1,318,706	1,256,361	62,346	11.3	5,517
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	578,189	305,256	366,604	(61,348)	22.3	(2,751)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	258,430	61,919	83,525	(21,606)	33.8	(639)
TOTAL WATSON LAKE			**4,113,025**	**1,997,936**	**2,081,695**	**(83,759)**		**(592)**
TOTAL PRODUCTION DIESEL PLANT			**13,684,978**	**6,399,211**	**6,786,796**	**(387,586)**	**-**	**(10,678)**
MOBILE								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	10,662	8,809	10,466	(1,657)	9.3	(178)
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	25,562	16,999	20,893	(3,894)	12.8	(304)
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	568,500	303,283	287,763	15,520	13.1	1,185
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	87,652	40,799	48,221	(7,422)	23.1	(321)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	92,170	12,008	16,120	(4,112)	35.5	(116)
TOTAL MOBILE			**784,546**	**381,898**	**383,463**	**(1,565)**		**265**
TOTAL GENERATION			**18,192,167**	**7,379,133**	**8,410,233**	**(1,031,099)**		**(26,994)**
SUBSTATION PLANT								
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50-R4	1,384,421	626,639	829,972	(203,333)	31.0	(6,559)
TOTAL SUBSTATION PLANT			**1,384,421**	**626,639**	**829,972**	**(203,333)**		**(6,559)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDULE 2A. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE ORIGINAL COST

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
DISTRIBUTION PLANT								
471.00	LAND RIGHTS	75-R3	1,267,608	151,638	151,507	131	67.3	2
473.00	POLES, TOWERS AND FIXTURES	45-R3	30,231,546	8,972,741	11,487,576	(2,514,836)	33.4	(75,294)
474.00	OVERHEAD CONDUCTOR	45-R4	20,514,612	5,832,601	7,036,909	(1,204,309)	32.3	(37,285)
474.10	OVERHEAD SERVICES	45-R3	2,849,453	1,023,337	1,271,831	(248,494)	33.4	(7,440)
475.00	UNDERGROUND CONDUIT	45-R3	20,982,589	6,074,457	5,608,170	466,287	32.6	14,303
475.10	UNDERGROUND SERVICES	40-R4	2,953,077	924,039	1,049,337	(125,298)	28.5	(4,396)
476.10	METERS	15-L0	1,683,985	682,328	41,448	640,880	10.6	60,460
476.30	AMR - METERS	15-R2.5	67,646	14,259	-	14,259	12.3	1,159
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	3,131,073	1,605,098	1,950,231	(345,133)	21.5	(16,053)
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	9,147,522	3,814,663	5,173,329	(1,358,667)	21.1	(64,392)
478.20	SENTINEL LIGHTS	23-R2	284,738	246,947	319,069	(72,122)	4.0	(18,030)
479.10	LINE TRANSFORMERS	45-R3	24,427,769	6,695,953	9,796,355	(3,100,402)	37.0	(83,795)
TOTAL DISTRIBUTION PLANT			**117,541,619**	**36,038,060**	**43,885,763**	**(7,847,703)**		**(230,761)**
GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	3,459,315	1,660,879	2,027,012	(366,133)	23.9	(15,319)
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	172,793	62,511	17,775	44,736	5.5	8,134
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	47,367	10,448	(11,313)	21,761	3.4	6,400
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	2,561,147	964,510	1,693,246	(728,736)	10.0	(72,874)
485.00	TOOLS AND INSTRUMENTS	15-SQ	719,184	273,558	239,068	34,490	8.7	3,964
486.00	COMMUNICATION EQUIPMENT	15-SQ	872,842	422,551	391,629	30,922	7.8	3,964
488.20	HOUSES	40-R3	473,256	152,396	1,717,512	(1,565,115)	21.8	(71,794)
TOTAL GENERAL PLANT			**8,305,904**	**3,546,853**	**6,074,929**	**(2,528,076)**		**(137,525)**
TOTAL UTILITY PLANT IN SERVICE			**145,424,111**	**47,590,686**	**59,200,897**	**(11,610,211)**		**(401,838)**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
GENERATION									
HYDRO PLANT (LIFE SPAN OF 2052)									
422.00	HYDRO STRUCTURES	ND	(10)	215,286	5,997	813	5,184	37.8	137
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	72-R2	(10)	1,875,073	31,671	4,367	27,304	40.4	676
425.00	HYDRO GENERATORS	103-R3	(10)	1,458,435	15,340	2,079	13,261	40.2	330
426.00	HYDRO ACCESSORIES AND EQUIPMENT	85-R3	(10)	105,192	4,849	657	4,192	32.2	130
427.00	HYDRO MISCELLANEOUS EQUIPMENT	45-R3	(10)	68,657	1,947	264	1,683	27.4	61
TOTAL HYDRO PLANT				**3,722,643**	**59,802**	**8,180**	**51,623**		**1,334**
PRODUCTION DIESEL PLANT									
BEAVER CREEK (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	37,488	2,225	(3,232)	5,457	18.9	289
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	92,859	8,138	1,494	6,645	22.0	302
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	535,779	36,744	20,345	16,399	9.6	1,708
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	173,365	-	2,313	(2,313)	25.9	(89)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	48,603	-	628	(628)	33.4	(19)
TOTAL BEAVER CREEK				**888,094**	**47,108**	**21,549**	**25,559**		**2,191**
CARMACKS (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	167,739	4,423	(6,423)	10,846	30.2	359
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	40,394	5,014	920	4,094	14.4	284
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	419,543	30,924	17,122	13,801	8.3	1,663
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	101,158	-	1,947	(1,947)	24.6	(79)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	7,366	-	529	(529)	36.0	(15)
TOTAL CARMACKS				**736,201**	**40,361**	**14,095**	**26,266**		**2,212**
DESTRUCTION BAY (LIFE SPAN OF 2023)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	42,282	3,122	(4,534)	7,656	9.5	806
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	105,478	10,910	2,003	8,908	11.6	768
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	488,076	14,004	7,754	6,250	11.0	568
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	284,627	-	882	(882)	11.5	(77)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	28,048	-	239	(239)	11.8	(20)
TOTAL DESTRUCTION BAY				**948,512**	**28,036**	**6,343**	**21,693**		**2,045**
HAINES JUNCTION (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	608,472	11,557	(16,783)	28,340	32.1	883
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	619,132	49,783	9,138	40,645	21.9	1,856
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	60,097	3,728	2,064	1,664	11.2	149
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	94,952	-	235	(235)	25.4	(9)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	2,454	-	64	(64)	33.4	(2)
TOTAL HAINES JUNCTION				**1,385,107**	**65,068**	**(5,283)**	**70,351**		**2,876**
OLD CROW (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	187,900	10,200	(14,813)	25,012	20.9	1,197
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	215,087	16,595	3,046	13,549	24.1	562
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	1,223,713	52,949	29,376	23,573	15.7	1,501
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	119,365	-	3,340	(3,340)	18.9	(177)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	171,496	-	907	(907)	26.9	(34)
TOTAL OLD CROW				**1,917,561**	**79,744**	**21,856**	**57,888**		**3,050**

YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
PELLY CROSSING (LIFE SPAN OF 2033)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	48,892	3,382	(4,912)	8,294	14.0	592
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	129,302	18,577	3,410	15,167	16.3	931
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	474,056	30,076	16,618	13,458	10.6	1,270
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	431,735	-	1,889	(1,889)	19.2	(98)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	61,485	-	513	(513)	20.5	(25)
TOTAL PELLY CROSSING				**1,145,469**	**52,035**	**17,518**	**34,517**		**2,669**
ROSS RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	171,221	5,738	(8,333)	14,072	28.0	503
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	85,126	6,592	1,210	5,382	22.2	242
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	189,753	14,710	8,145	6,565	7.3	899
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	124,872	-	926	(926)	23.5	(39)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	9,639	-	251	(251)	33.9	(7)
TOTAL ROSS RIVER				**580,611**	**27,040**	**2,199**	**24,841**		**1,597**
STEWART CROSSING (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	247,966	6,427	(9,333)	15,760	30.3	520
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	65,107	2,986	548	2,438	28.5	86
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	45,677	2,485	1,256	1,229	10.9	113
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	70,425	-	143	(143)	24.9	(6)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	84,682	-	39	(39)	35.4	(1)
TOTAL STEWART CROSSING				**513,857**	**11,897**	**(7,348)**	**19,245**		**712**
SWIFT RIVER (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	22,503	991	(1,439)	2,430	24.9	98
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	63,430	7,529	1,382	6,147	15.7	392
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	241,047	9,881	5,491	4,391	16.3	269
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	93,560	-	624	(624)	25.0	(25)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	11,924	-	170	(170)	30.6	(6)
TOTAL SWIFT RIVER				**432,465**	**18,401**	**6,228**	**12,174**		**728**
TESLIN (LIFE SPAN OF 2053)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	37,986	1,044	(1,516)	2,559	28.9	89
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	99,863	4,524	830	3,693	27.5	134
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	762,034	52,443	29,038	23,405	9.6	2,438
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	54,417	-	3,301	(3,301)	21.5	(154)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	69,778	-	897	(897)	33.9	(26)
TOTAL TESLIN				**1,024,077**	**58,011**	**32,550**	**25,461**		**2,481**
WATSON LAKE (LIFE SPAN OF 2113)									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	359,393	20,394	(29,617)	50,011	20.1	2,488
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	747,818	21,623	3,969	17,654	30.6	577
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	2,169,195	131,871	72,943	58,928	11.3	5,215
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	578,189	-	8,293	(8,293)	22.3	(372)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	258,430	-	2,252	(2,252)	33.8	(67)
TOTAL WATSON LAKE				**4,113,025**	**173,888**	**57,840**	**116,048**		**7,841**
TOTAL PRODUCTION DIESEL PLANT				**13,684,978**	**601,587**	**167,547**	**434,040**		**28,403**

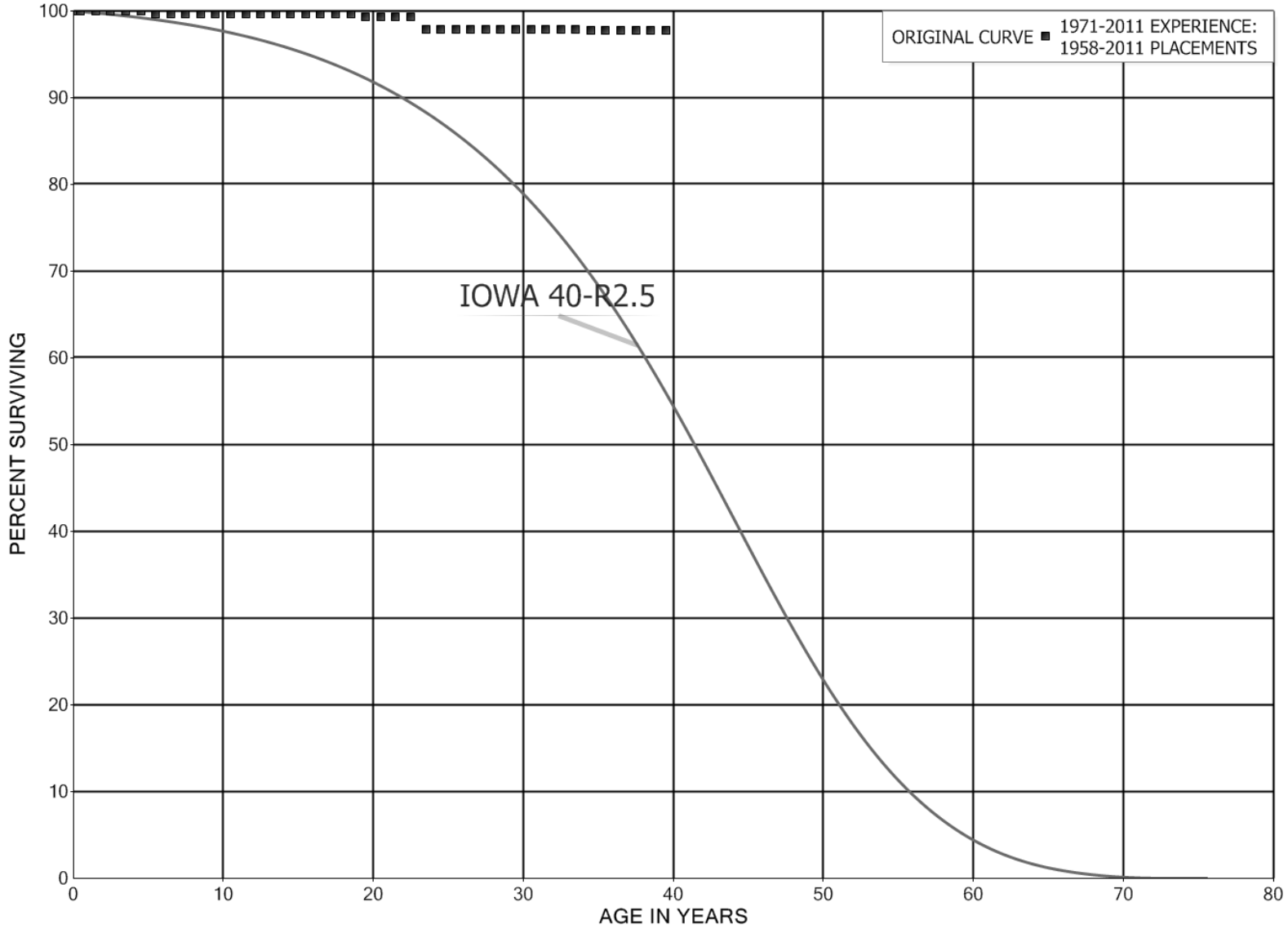
YUKON ELECTRICAL COMPANY LIMITED

SCHEDUALE 2B: ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2011

RELATED TO THE RECOVERY OF THE NET SALVAGE ESTIMATES

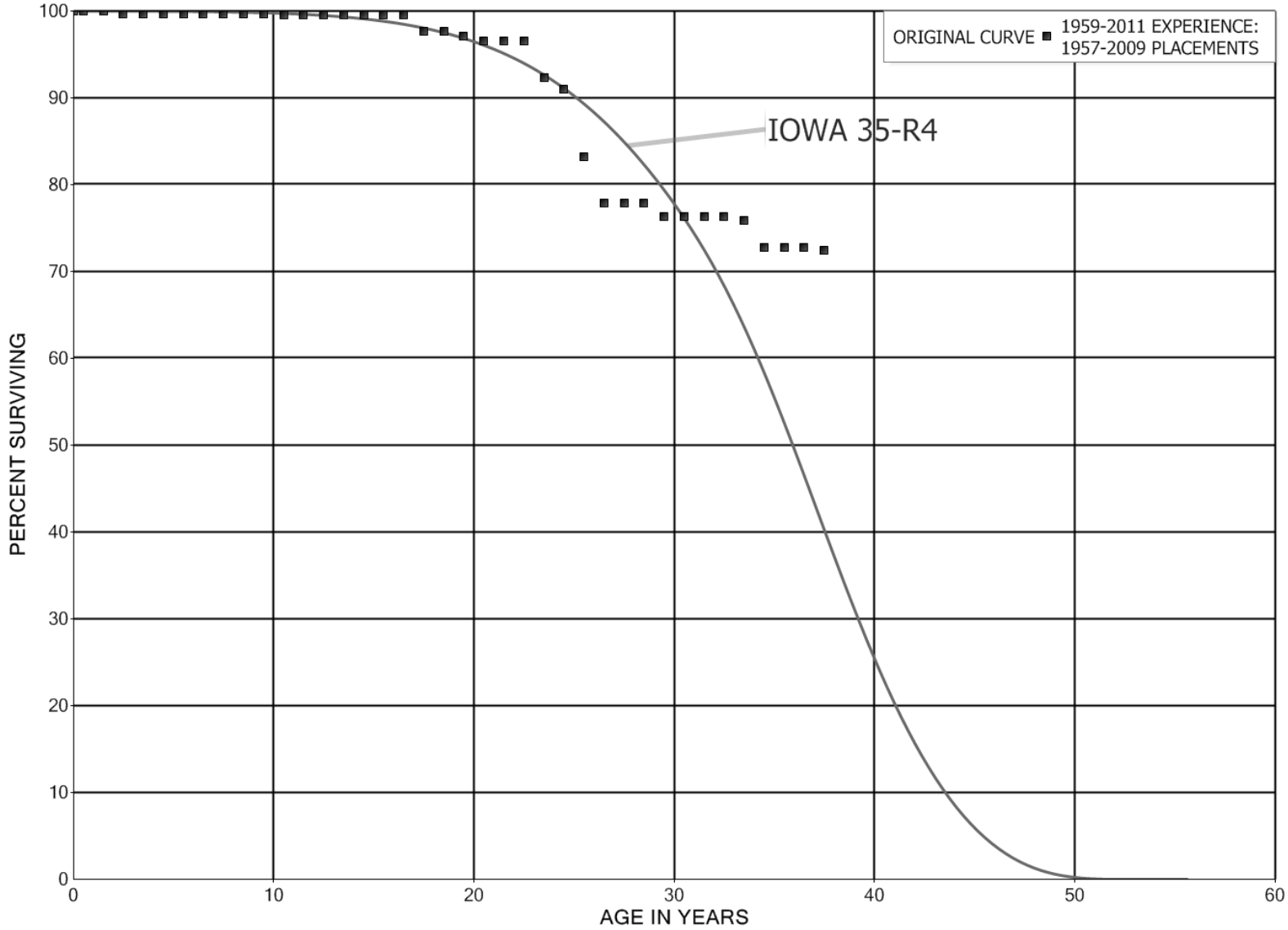
	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE %	SURVIVING ORIGINAL COST AS OF DECEMBER 31, 2011	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)
MOBILE									
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	(10)	10,662	881	(1,279)	2,160	9.3	232
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	(20)	25,562	3,400	624	2,776	12.8	217
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	(10)	568,500	30,328	16,707	13,621	13.1	1,040
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	0	87,652	-	1,899	(1,899)	23.1	(82)
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	0	92,170	-	516	(516)	35.5	(15)
TOTAL MOBILE				**784,546**	**34,609**	**18,467**	**16,142**		**1,392**
TOTAL GENERATION				**18,192,167**	**695,999**	**194,194**	**501,805**		**31,130**
SUBSTATION PLANT									
457.00	SUBSTATION EQUIPMENT - TRANSMISSION		(10)	1,384,421	62,664	21,171	41,493	31.0	1,338
TOTAL SUBSTATION PLANT				**1,384,421**	**62,664**	**21,171**	**41,493**		**1,338**
DISTRIBUTION PLANT									
471.00	LAND RIGHTS	75-R3	0	1,267,608	-	(166)	166	67.3	2
473.00	POLES, TOWERS AND FIXTURES	45-R3	(75)	30,231,546	6,729,555	3,685,089	3,044,466	33.4	91,152
474.00	OVERHEAD CONDUCTOR	45-R4	(80)	20,514,612	4,666,080	2,290,803	2,375,277	32.3	73,538
474.10	OVERHEAD SERVICES	45-R3	(10)	2,849,453	102,334	68,292	34,041	33.4	1,019
475.00	UNDERGROUND CONDUIT	45-R3	(50)	20,982,589	3,037,229	(74,602)	3,111,831	32.6	95,455
475.10	UNDERGROUND SERVICES	40-R4	(10)	2,953,077	92,404	3,618	88,786	28.5	3,115
476.10	METERS	15-L0	0	1,683,985	-	27,423	(27,423)	10.6	(2,587)
476.30	AMR - METERS	15-R2.5	0	67,646	-	-	-	12.3	-
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	(10)	3,131,073	160,510	(128,522)	289,032	21.5	13,443
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	(10)	9,147,522	381,466	(265,776)	647,242	21.1	30,675
478.20	SENTINEL LIGHTS	23-R2	0	284,738	-	(105,624)	105,624	4.0	26,406
479.10	LINE TRANSFORMERS		(10)	24,427,769	669,595	311,505	358,090	37.0	9,678
TOTAL DISTRIBUTION PLANT				**117,541,619**	**15,839,174**	**5,812,042**	**10,027,132**		**341,897**
GENERAL PLANT									
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	0	3,459,315	-	(135,119)	135,119	23.9	5,654
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	172,793	-	(4,613)	4,613	5.5	839
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	0	47,367	-	-	-	3.4	-
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	25	2,561,147	-	(408,732)	408,732	10.0	40,873
485.00	TOOLS AND INSTRUMENTS	15-SQ	0	719,184	-	141	(141)	8.7	(16)
486.00	COMMUNICATION EQUIPMENT	15-SQ	0	872,842	-	(6,237)	6,237	7.8	800
488.20	HOUSES		(10)	473,256	15,240	(1,077,696)	1,092,936	21.8	50,135
TOTAL GENERAL PLANT				**8,305,904**	**15,240**	**(1,632,256)**	**1,647,495**		**98,283**
TOTAL UTILITY PLANT IN SERVICE			**-**	**145,424,111**	**16,613,076**	**4,395,151**	**12,217,925**	**-**	**472,649**

PART IV. SERVICE LIFE STATISTICS


ORIGINAL CURVE
1971-2011 EXPERIENCE:
1958-2011 PLACEMENTS
IOWA 40-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

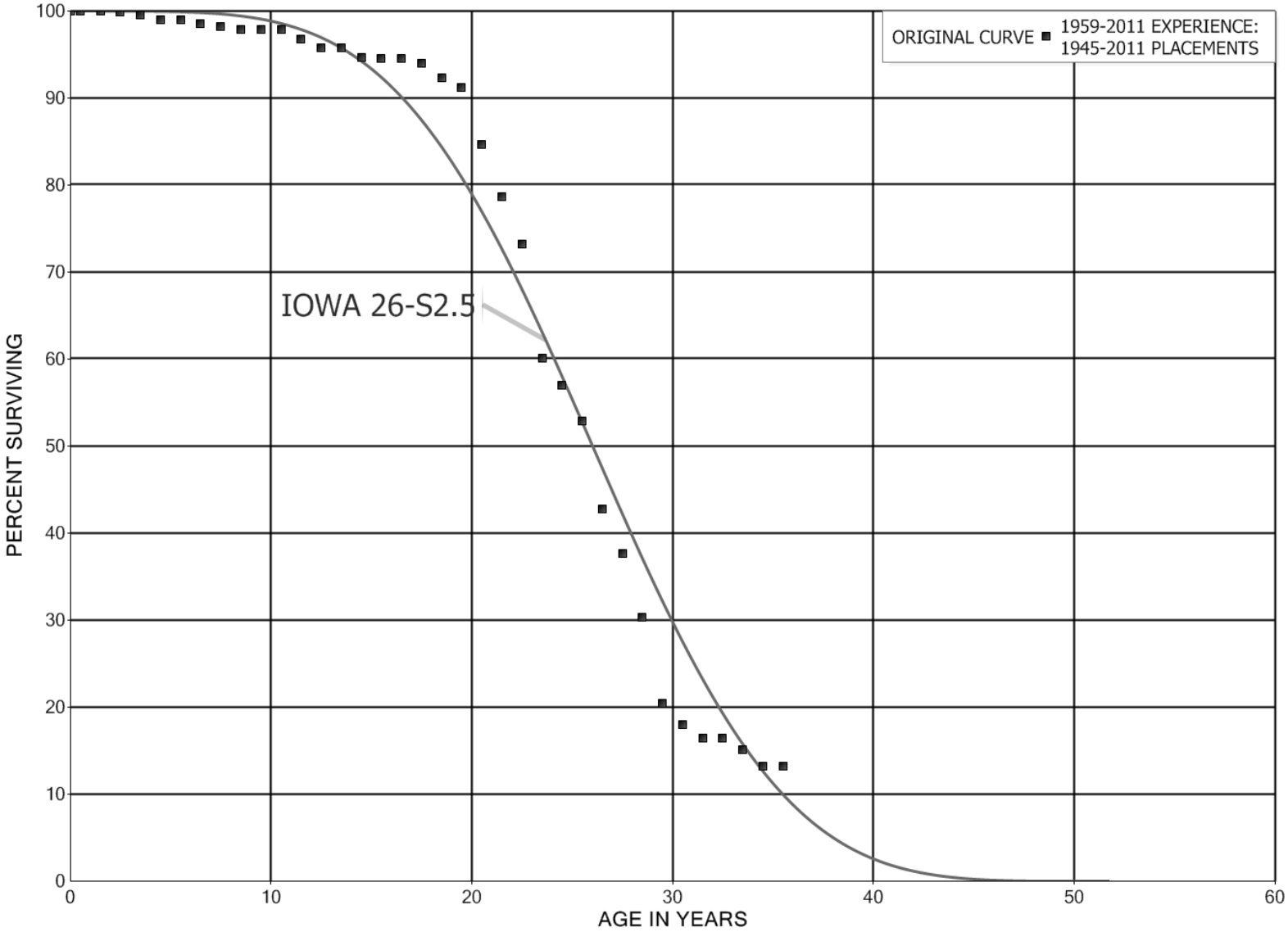
PLACEMENT BAND 1958-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,654,355		0.0000	1.0000	100.00
0.5	1,864,466		0.0000	1.0000	100.00
1.5	1,926,396		0.0000	1.0000	100.00
2.5	1,901,065		0.0000	1.0000	100.00
3.5	1,578,385		0.0000	1.0000	100.00
4.5	1,402,603	5,674	0.0040	0.9960	100.00
5.5	1,175,602		0.0000	1.0000	99.60
6.5	932,589		0.0000	1.0000	99.60
7.5	931,587		0.0000	1.0000	99.60
8.5	931,587		0.0000	1.0000	99.60
9.5	931,587		0.0000	1.0000	99.60
10.5	931,401		0.0000	1.0000	99.60
11.5	931,407		0.0000	1.0000	99.60
12.5	901,724		0.0000	1.0000	99.60
13.5	847,579		0.0000	1.0000	99.60
14.5	794,374		0.0000	1.0000	99.60
15.5	785,466		0.0000	1.0000	99.60
16.5	785,466		0.0000	1.0000	99.60
17.5	785,466		0.0000	1.0000	99.60
18.5	726,307	2,028	0.0028	0.9972	99.60
19.5	714,137	100	0.0001	0.9999	99.32
20.5	712,627		0.0000	1.0000	99.30
21.5	712,627		0.0000	1.0000	99.30
22.5	682,808	10,000	0.0146	0.9854	99.30
23.5	633,423		0.0000	1.0000	97.85
24.5	322,062		0.0000	1.0000	97.85
25.5	299,940		0.0000	1.0000	97.85
26.5	285,988	6	0.0000	1.0000	97.85
27.5	285,982		0.0000	1.0000	97.85
28.5	243,920		0.0000	1.0000	97.85
29.5	188,582		0.0000	1.0000	97.85
30.5	188,582		0.0000	1.0000	97.85
31.5	188,582		0.0000	1.0000	97.85
32.5	188,582		0.0000	1.0000	97.85
33.5	188,412	170	0.0009	0.9991	97.85
34.5	188,241		0.0000	1.0000	97.76
35.5	172,665		0.0000	1.0000	97.76
36.5	172,665		0.0000	1.0000	97.76
37.5	163,958		0.0000	1.0000	97.76
38.5	163,958		0.0000	1.0000	97.76
39.5	163,958		0.0000	1.0000	97.76
40.5					97.76


ORIGINAL CURVE
1959-2011 EXPERIENCE:
1957-2009 PLACEMENTS
IOWA 35-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,350,676		0.0000	1.0000	100.00
0.5	2,351,040		0.0000	1.0000	100.00
1.5	2,360,650	7,910	0.0034	0.9966	100.00
2.5	2,203,751		0.0000	1.0000	99.66
3.5	2,176,571	1,700	0.0008	0.9992	99.66
4.5	2,149,309	8	0.0000	1.0000	99.59
5.5	2,049,062	349	0.0002	0.9998	99.59
6.5	1,363,674		0.0000	1.0000	99.57
7.5	1,323,497		0.0000	1.0000	99.57
8.5	1,249,302		0.0000	1.0000	99.57
9.5	1,249,302	302	0.0002	0.9998	99.57
10.5	1,249,000		0.0000	1.0000	99.55
11.5	1,249,000		0.0000	1.0000	99.55
12.5	1,102,899		0.0000	1.0000	99.55
13.5	890,869	2	0.0000	1.0000	99.55
14.5	493,722		0.0000	1.0000	99.55
15.5	488,252		0.0000	1.0000	99.55
16.5	488,252	9,322	0.0191	0.9809	99.55
17.5	386,740		0.0000	1.0000	97.64
18.5	260,407	1,640	0.0063	0.9937	97.64
19.5	258,767	1,491	0.0058	0.9942	97.03
20.5	257,276		0.0000	1.0000	96.47
21.5	243,142		0.0000	1.0000	96.47
22.5	233,206	10,000	0.0429	0.9571	96.47
23.5	136,226	1,986	0.0146	0.9854	92.33
24.5	113,405	9,712	0.0856	0.9144	90.99
25.5	96,604	6,230	0.0645	0.9355	83.20
26.5	90,373		0.0000	1.0000	77.83
27.5	90,373		0.0000	1.0000	77.83
28.5	90,373	1,774	0.0196	0.9804	77.83
29.5	36,524		0.0000	1.0000	76.30
30.5	36,524		0.0000	1.0000	76.30
31.5	36,524		0.0000	1.0000	76.30
32.5	36,524	228	0.0062	0.9938	76.30
33.5	35,307	1,426	0.0404	0.9596	75.83
34.5	33,881		0.0000	1.0000	72.76
35.5	25,481		0.0000	1.0000	72.76
36.5	25,481	120	0.0047	0.9953	72.76
37.5	25,361	7,892	0.3112	0.6888	72.42
38.5	12,407		0.0000	1.0000	49.89
39.5	12,407	9,402	0.7578	0.2422	49.89
40.5					12.08

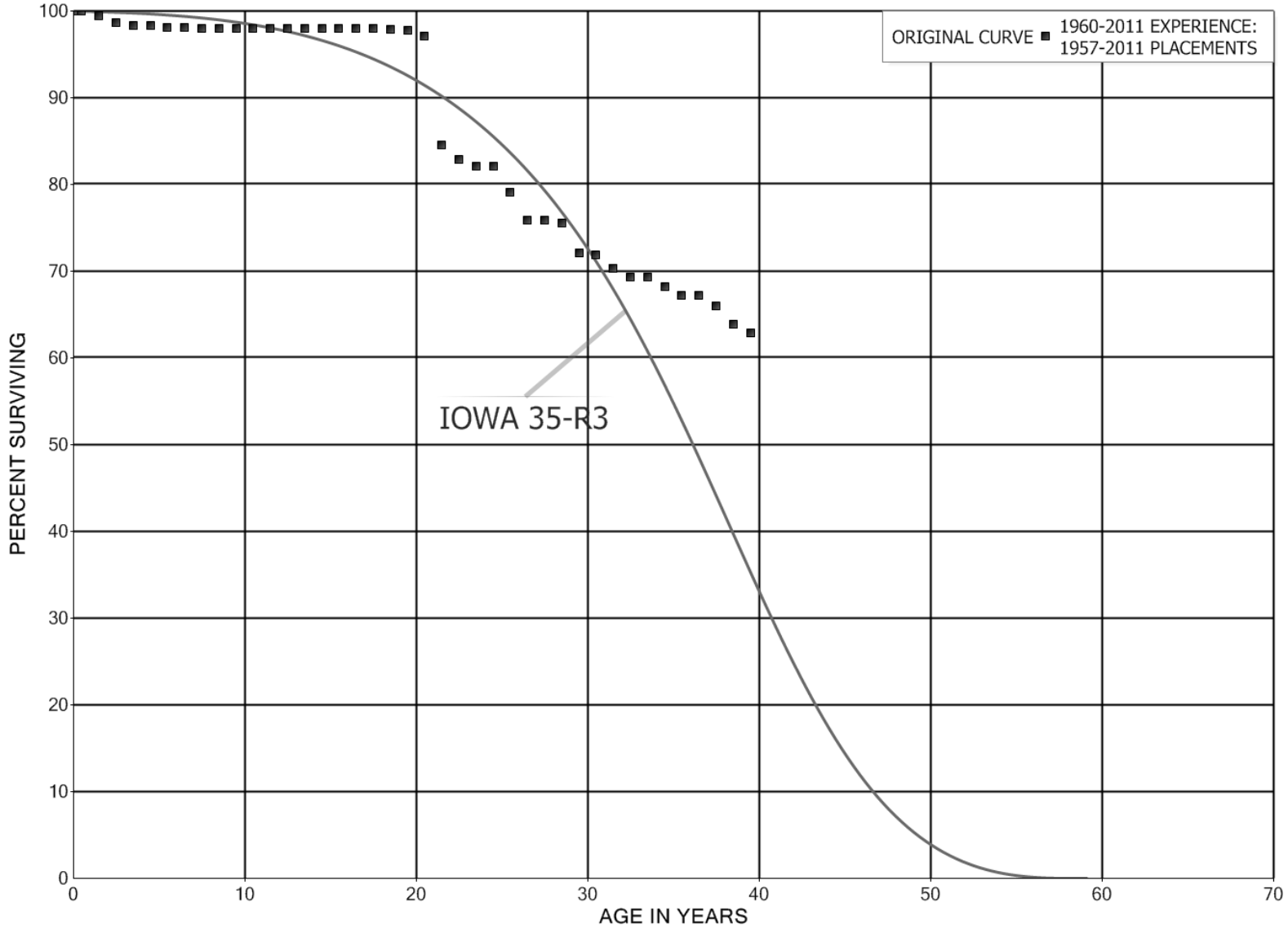

ORIGINAL CURVE
1959-2011 EXPERIENCE:
1945-2011 PLACEMENTS
IOWA 26-S2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,469,065		0.0000	1.0000	100.00
0.5	10,028,165	6,784	0.0007	0.9993	100.00
1.5	9,872,312	10,726	0.0011	0.9989	99.93
2.5	9,816,261	34,933	0.0036	0.9964	99.82
3.5	9,792,298	45,431	0.0046	0.9954	99.47
4.5	9,750,407	8,231	0.0008	0.9992	99.01
5.5	9,742,176	41,215	0.0042	0.9958	98.92
6.5	9,700,961	32,634	0.0034	0.9966	98.50
7.5	8,863,532	28,717	0.0032	0.9968	98.17
8.5	8,687,204		0.0000	1.0000	97.86
9.5	8,680,481		0.0000	1.0000	97.86
10.5	8,680,481	99,081	0.0114	0.9886	97.86
11.5	8,548,182	88,184	0.0103	0.9897	96.74
12.5	7,828,406	3,256	0.0004	0.9996	95.74
13.5	7,420,399	84,893	0.0114	0.9886	95.70
14.5	7,220,912	4,879	0.0007	0.9993	94.61
15.5	6,908,491	20	0.0000	1.0000	94.54
16.5	6,908,471	42,331	0.0061	0.9939	94.54
17.5	6,673,533	120,226	0.0180	0.9820	93.96
18.5	5,450,561	62,147	0.0114	0.9886	92.27
19.5	5,272,487	384,392	0.0729	0.9271	91.22
20.5	3,651,535	255,728	0.0700	0.9300	84.57
21.5	3,240,457	224,816	0.0694	0.9306	78.64
22.5	2,769,342	496,700	0.1794	0.8206	73.19
23.5	2,203,869	115,677	0.0525	0.9475	60.06
24.5	2,018,037	144,761	0.0717	0.9283	56.91
25.5	1,818,722	346,467	0.1905	0.8095	52.83
26.5	844,799	101,376	0.1200	0.8800	42.76
27.5	736,475	143,124	0.1943	0.8057	37.63
28.5	555,062	181,518	0.3270	0.6730	30.32
29.5	373,543	44,154	0.1182	0.8818	20.40
30.5	319,620	27,884	0.0872	0.9128	17.99
31.5	291,736		0.0000	1.0000	16.42
32.5	291,736	23,957	0.0821	0.9179	16.42
33.5	264,964	32,625	0.1231	0.8769	15.07
34.5	218,890		0.0000	1.0000	13.22
35.5	218,890	14,731	0.0673	0.9327	13.22
36.5	204,159	4,886	0.0239	0.9761	12.33
37.5	189,046	19,856	0.1050	0.8950	12.03
38.5	157,819	15,939	0.1010	0.8990	10.77

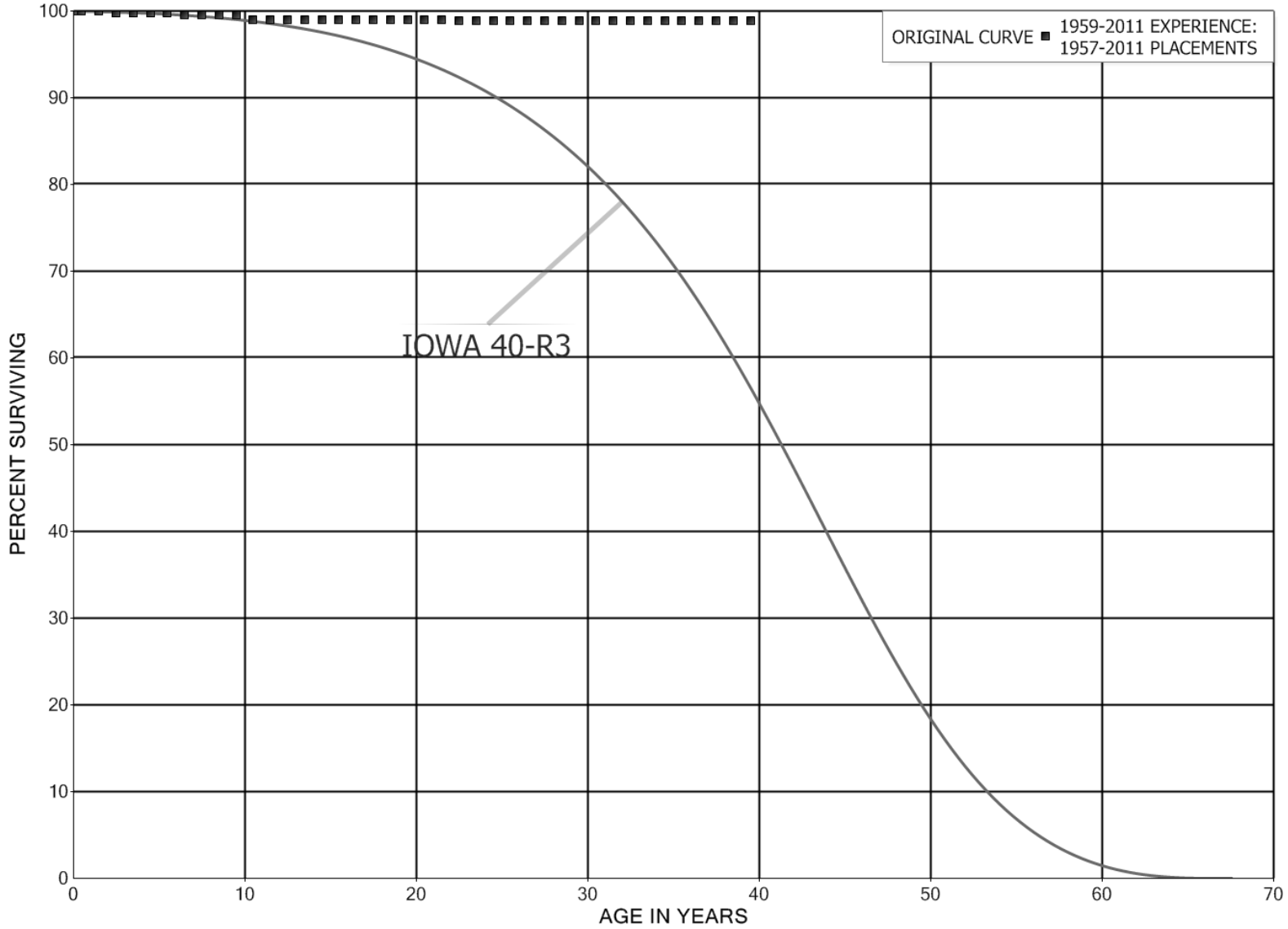
PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	139,654	128,185	0.9179	0.0821	9.68
40.5	11,469	11,319	0.9869	0.0131	0.80
41.5	150		0.0000	1.0000	0.01
42.5	150		0.0000	1.0000	0.01
43.5	150		0.0000	1.0000	0.01
44.5	150		0.0000	1.0000	0.01
45.5	150		0.0000	1.0000	0.01
46.5	150		0.0000	1.0000	0.01
47.5	150		0.0000	1.0000	0.01
48.5	150		0.0000	1.0000	0.01
49.5	150		0.0000	1.0000	0.01
50.5	150		0.0000	1.0000	0.01
51.5	150	150	1.0000		0.01
52.5					


ORIGINAL CURVE
1960-2011 EXPERIENCE:
1957-2011 PLACEMENTS
IOWA 35-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70

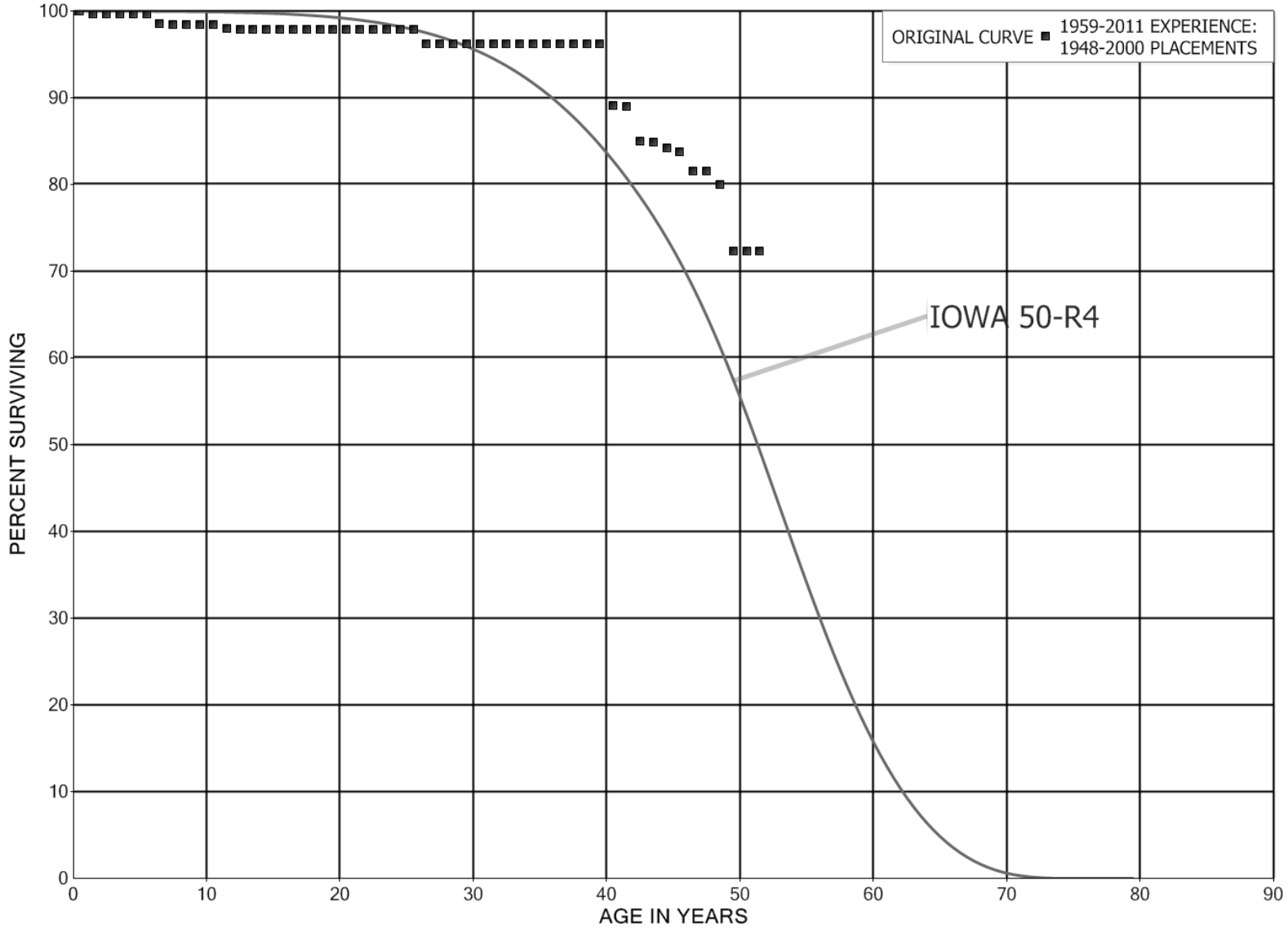
PLACEMENT BAND 1957-2011 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,419,371		0.0000	1.0000	100.00
0.5	2,397,443	15,260	0.0064	0.9936	100.00
1.5	2,385,458	17,240	0.0072	0.9928	99.36
2.5	2,366,911	7,468	0.0032	0.9968	98.65
3.5	2,163,664		0.0000	1.0000	98.33
4.5	2,093,865	4,681	0.0022	0.9978	98.33
5.5	2,060,311	2,159	0.0010	0.9990	98.11
6.5	2,053,192	240	0.0001	0.9999	98.01
7.5	2,014,624		0.0000	1.0000	98.00
8.5	1,884,783		0.0000	1.0000	98.00
9.5	1,854,047		0.0000	1.0000	98.00
10.5	1,666,069		0.0000	1.0000	98.00
11.5	1,487,309		0.0000	1.0000	98.00
12.5	1,323,617		0.0000	1.0000	98.00
13.5	1,202,777		0.0000	1.0000	98.00
14.5	982,900		0.0000	1.0000	98.00
15.5	982,900		0.0000	1.0000	98.00
16.5	982,900		0.0000	1.0000	98.00
17.5	973,543	1,500	0.0015	0.9985	98.00
18.5	883,105	809	0.0009	0.9991	97.85
19.5	855,100	6,347	0.0074	0.9926	97.76
20.5	833,797	107,410	0.1288	0.8712	97.03
21.5	604,548	12,194	0.0202	0.9798	84.53
22.5	492,295	4,746	0.0096	0.9904	82.83
23.5	487,549		0.0000	1.0000	82.03
24.5	267,341	9,712	0.0363	0.9637	82.03
25.5	228,899	9,232	0.0403	0.9597	79.05
26.5	218,258		0.0000	1.0000	75.86
27.5	209,162	1,069	0.0051	0.9949	75.86
28.5	204,571	9,326	0.0456	0.9544	75.47
29.5	168,525	417	0.0025	0.9975	72.03
30.5	163,725	3,584	0.0219	0.9781	71.86
31.5	156,292	2,134	0.0137	0.9863	70.28
32.5	154,157		0.0000	1.0000	69.32
33.5	154,157	2,454	0.0159	0.9841	69.32
34.5	151,542	2,274	0.0150	0.9850	68.22
35.5	145,808	104	0.0007	0.9993	67.20
36.5	145,704	2,615	0.0179	0.9821	67.15
37.5	137,309	4,462	0.0325	0.9675	65.94
38.5	117,869	1,850	0.0157	0.9843	63.80
39.5	98,916	21,142	0.2137	0.7863	62.80
40.5					49.38


ORIGINAL CURVE
1959-2011 EXPERIENCE:
1957-2011 PLACEMENTS
IOWA 40-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70

PLACEMENT BAND 1957-2011 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	865,043		0.0000	1.0000	100.00
0.5	773,326		0.0000	1.0000	100.00
1.5	764,224	2,205	0.0029	0.9971	100.00
2.5	708,538		0.0000	1.0000	99.71
3.5	681,596		0.0000	1.0000	99.71
4.5	423,105		0.0000	1.0000	99.71
5.5	396,037	1,000	0.0025	0.9975	99.71
6.5	376,681		0.0000	1.0000	99.46
7.5	315,109		0.0000	1.0000	99.46
8.5	278,011		0.0000	1.0000	99.46
9.5	278,011	1,327	0.0048	0.9952	99.46
10.5	276,684		0.0000	1.0000	98.98
11.5	275,234		0.0000	1.0000	98.98
12.5	267,187		0.0000	1.0000	98.98
13.5	239,739		0.0000	1.0000	98.98
14.5	185,125		0.0000	1.0000	98.98
15.5	185,049		0.0000	1.0000	98.98
16.5	185,049		0.0000	1.0000	98.98
17.5	185,049		0.0000	1.0000	98.98
18.5	184,851		0.0000	1.0000	98.98
19.5	92,609		0.0000	1.0000	98.98
20.5	58,574		0.0000	1.0000	98.98
21.5	58,574	64	0.0011	0.9989	98.98
22.5	58,510		0.0000	1.0000	98.88
23.5	58,510		0.0000	1.0000	98.88
24.5	44,076		0.0000	1.0000	98.88
25.5	44,076		0.0000	1.0000	98.88
26.5	44,076		0.0000	1.0000	98.88
27.5	44,076		0.0000	1.0000	98.88
28.5	44,076		0.0000	1.0000	98.88
29.5	21,773		0.0000	1.0000	98.88
30.5	21,773		0.0000	1.0000	98.88
31.5	21,773		0.0000	1.0000	98.88
32.5	17,594		0.0000	1.0000	98.88
33.5	17,594		0.0000	1.0000	98.88
34.5	17,594		0.0000	1.0000	98.88
35.5	17,594		0.0000	1.0000	98.88
36.5	17,594		0.0000	1.0000	98.88
37.5	17,594		0.0000	1.0000	98.88
38.5	17,594		0.0000	1.0000	98.88
39.5	17,594	14,213	0.8078	0.1922	98.88
40.5					19.00

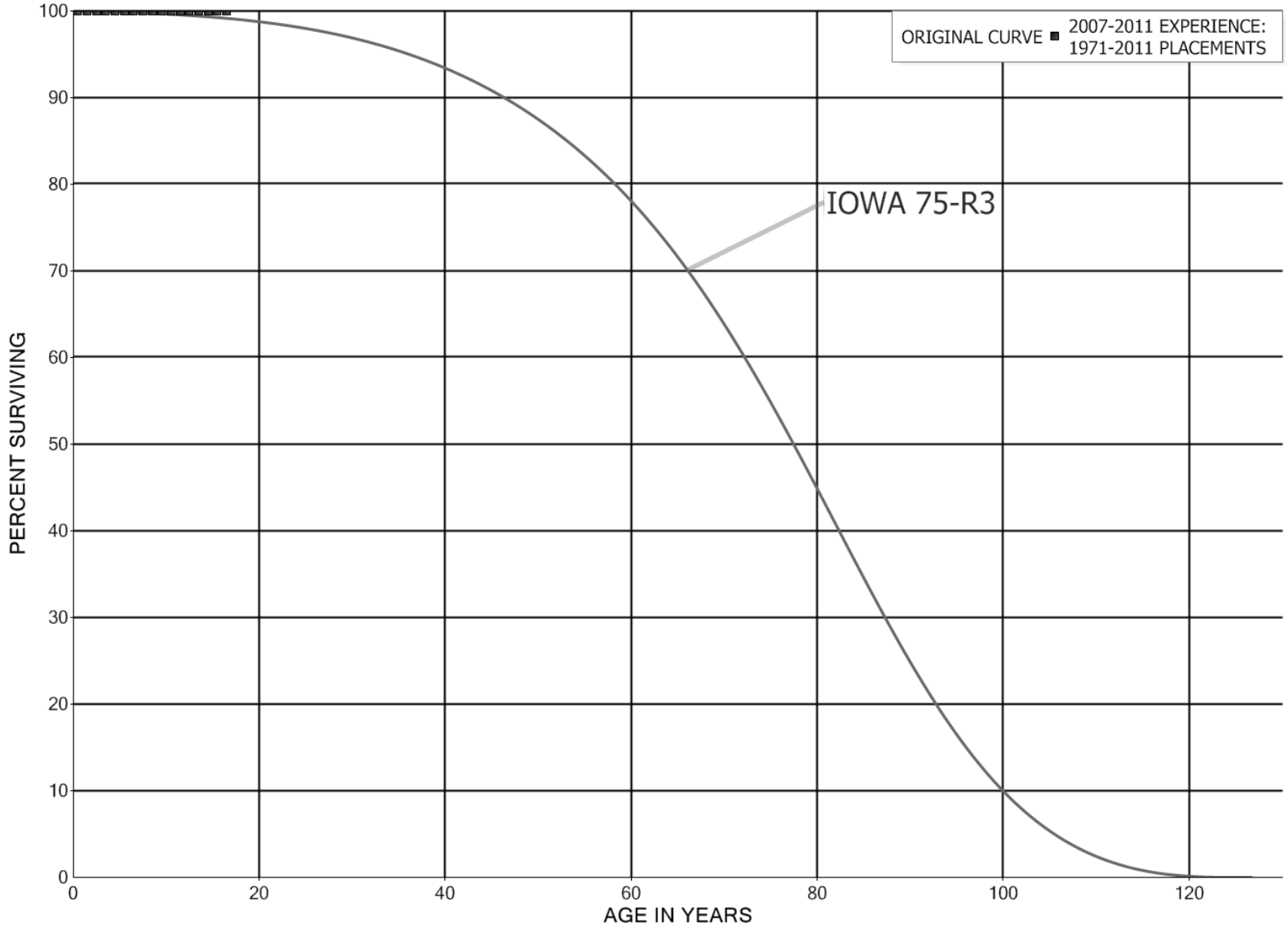

ORIGINAL CURVE
1959-2011 EXPERIENCE:
1948-2000 PLACEMENTS
IOWA 50-R4
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

PLACEMENT BAND 1948-2000 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,052,255		0.0000	1.0000	100.00
0.5	1,415,445	4,796	0.0034	0.9966	100.00
1.5	1,423,083		0.0000	1.0000	99.66
2.5	1,423,083		0.0000	1.0000	99.66
3.5	1,423,083		0.0000	1.0000	99.66
4.5	1,423,083	253	0.0002	0.9998	99.66
5.5	1,422,830	16,423	0.0115	0.9885	99.64
6.5	1,406,407	1,349	0.0010	0.9990	98.49
7.5	1,405,058		0.0000	1.0000	98.40
8.5	1,405,058		0.0000	1.0000	98.40
9.5	1,405,058		0.0000	1.0000	98.40
10.5	1,415,843	5,610	0.0040	0.9960	98.40
11.5	1,406,152	2,888	0.0021	0.9979	98.01
12.5	1,341,224	118	0.0001	0.9999	97.81
13.5	1,341,106		0.0000	1.0000	97.80
14.5	1,246,953		0.0000	1.0000	97.80
15.5	1,098,975	79	0.0001	0.9999	97.80
16.5	1,098,896		0.0000	1.0000	97.79
17.5	1,098,896		0.0000	1.0000	97.79
18.5	638,467		0.0000	1.0000	97.79
19.5	407,160		0.0000	1.0000	97.79
20.5	407,160	33	0.0001	0.9999	97.79
21.5	407,127		0.0000	1.0000	97.78
22.5	388,651		0.0000	1.0000	97.78
23.5	367,054		0.0000	1.0000	97.78
24.5	367,054		0.0000	1.0000	97.78
25.5	324,038	5,175	0.0160	0.9840	97.78
26.5	304,260		0.0000	1.0000	96.22
27.5	294,670		0.0000	1.0000	96.22
28.5	294,670		0.0000	1.0000	96.22
29.5	291,460		0.0000	1.0000	96.22
30.5	283,310		0.0000	1.0000	96.22
31.5	283,310		0.0000	1.0000	96.22
32.5	283,310		0.0000	1.0000	96.22
33.5	283,310		0.0000	1.0000	96.22
34.5	283,310		0.0000	1.0000	96.22
35.5	283,310		0.0000	1.0000	96.22
36.5	139,701		0.0000	1.0000	96.22
37.5	98,451		0.0000	1.0000	96.22
38.5	98,451		0.0000	1.0000	96.22

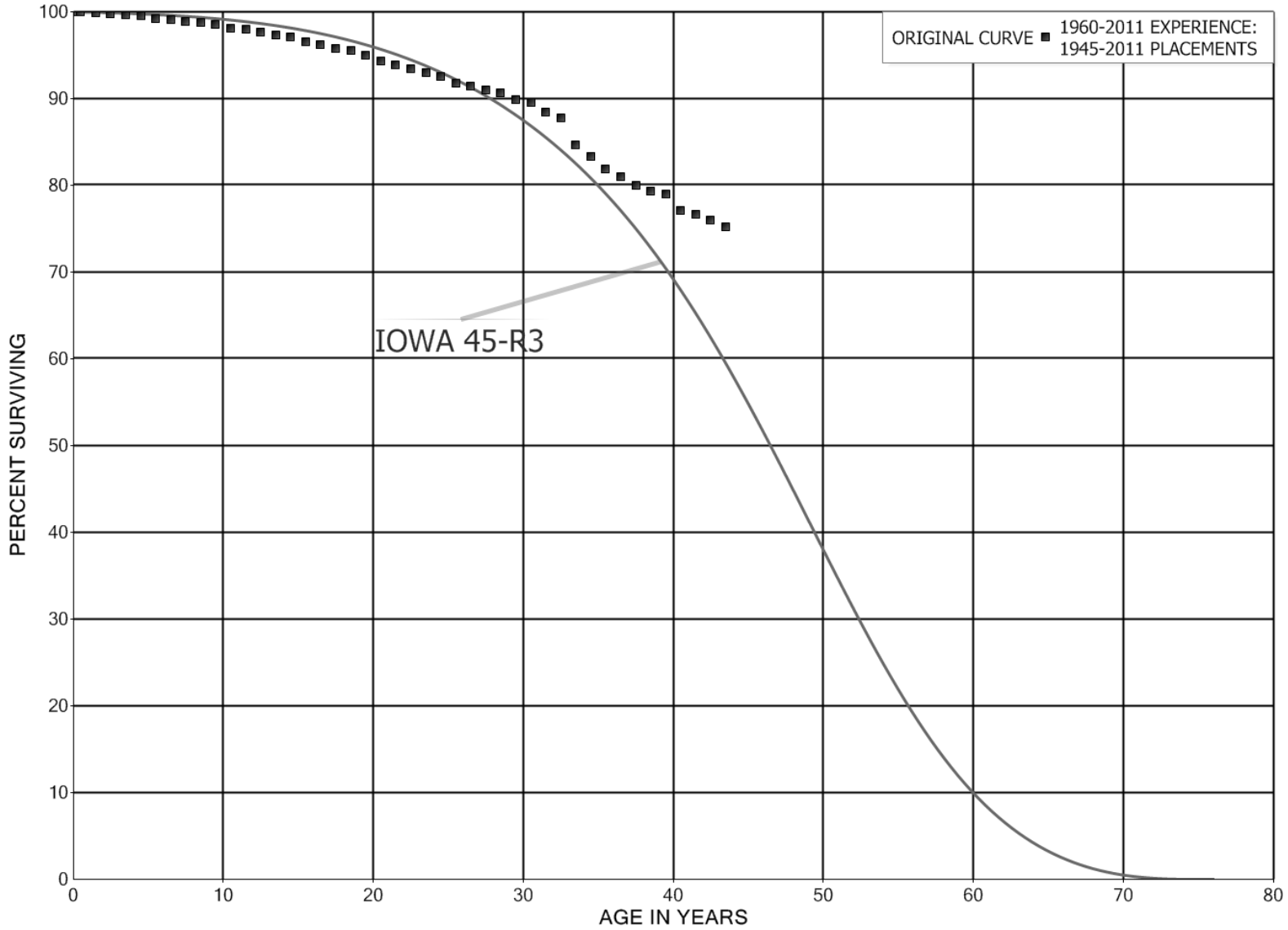
PLACEMENT BAND 1948-2000 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	98,451	7,356	0.0747	0.9253	96.22
40.5	87,165	36	0.0004	0.9996	89.03
41.5	69,358	3,165	0.0456	0.9544	89.00
42.5	40,931	34	0.0008	0.9992	84.94
43.5	26,880	221	0.0082	0.9918	84.87
44.5	20,780	115	0.0055	0.9945	84.17
45.5	20,603	547	0.0266	0.9734	83.70
46.5	19,645		0.0000	1.0000	81.48
47.5	19,431	354	0.0182	0.9818	81.48
48.5	18,061	1,739	0.0963	0.9037	79.99
49.5	16,322		0.0000	1.0000	72.29
50.5	15,664		0.0000	1.0000	72.29
51.5	12,434	3,953	0.3179	0.6821	72.29
52.5	8,482		0.0000	1.0000	49.31
53.5	8,482		0.0000	1.0000	49.31
54.5					49.31


ORIGINAL CURVE
2007-2011 EXPERIENCE:
1971-2011 PLACEMENTS
IOWA 75-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

PLACEMENT BAND 1971-2011 EXPERIENCE BAND 2007-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	407,391		0.0000	1.0000	100.00
0.5	379,408		0.0000	1.0000	100.00
1.5	496,651		0.0000	1.0000	100.00
2.5	484,652		0.0000	1.0000	100.00
3.5	382,967		0.0000	1.0000	100.00
4.5	347,887		0.0000	1.0000	100.00
5.5	356,980		0.0000	1.0000	100.00
6.5	202,566		0.0000	1.0000	100.00
7.5	191,644		0.0000	1.0000	100.00
8.5	240,193		0.0000	1.0000	100.00
9.5	345,659		0.0000	1.0000	100.00
10.5	336,396		0.0000	1.0000	100.00
11.5	331,701		0.0000	1.0000	100.00
12.5	294,397		0.0000	1.0000	100.00
13.5	243,875		0.0000	1.0000	100.00
14.5	103,762		0.0000	1.0000	100.00
15.5	57,676		0.0000	1.0000	100.00
16.5	12,701		0.0000	1.0000	100.00
17.5					100.00
18.5					
19.5					
20.5					
21.5					
22.5					
23.5					
24.5					
25.5					
26.5					
27.5	198		0.0000		
28.5	198		0.0000		
29.5	198		0.0000		
30.5	198		0.0000		
31.5	198		0.0000		
32.5					
33.5					
34.5					
35.5	1,500		0.0000		
36.5	1,500		0.0000		
37.5	1,500		0.0000		
38.5	1,500		0.0000		
39.5	1,500		0.0000		
40.5					

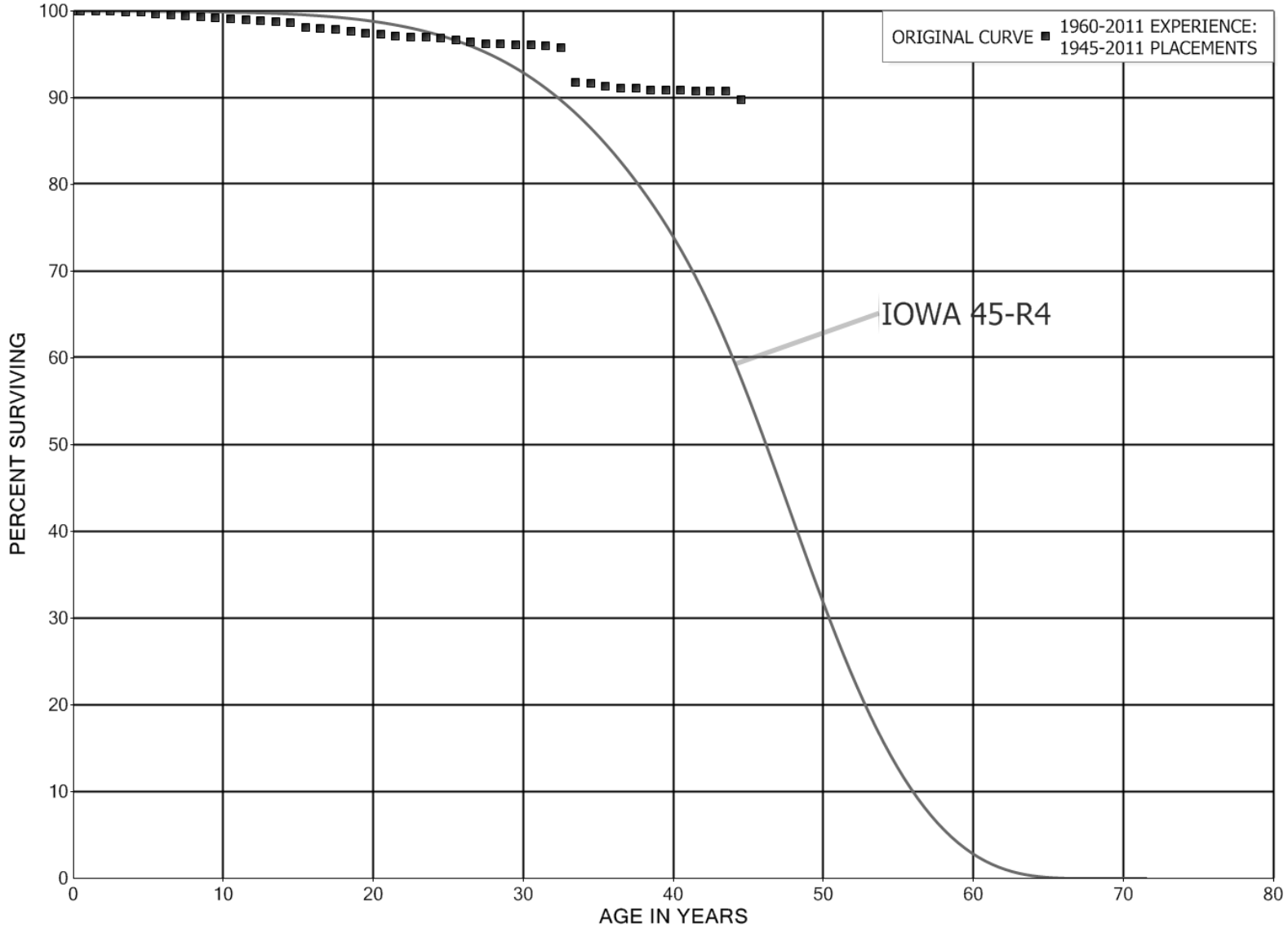

ORIGINAL CURVE
1960-2011 EXPERIENCE:
1945-2011 PLACEMENTS
IOWA 45-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,568,573	1,856	0.0001	0.9999	100.00
0.5	26,595,181	34,714	0.0013	0.9987	99.99
1.5	25,717,605	40,985	0.0016	0.9984	99.86
2.5	25,355,606	25,846	0.0010	0.9990	99.70
3.5	23,716,776	35,921	0.0015	0.9985	99.60
4.5	22,593,758	55,885	0.0025	0.9975	99.45
5.5	21,141,482	29,923	0.0014	0.9986	99.21
6.5	20,126,699	49,725	0.0025	0.9975	99.07
7.5	18,798,226	20,613	0.0011	0.9989	98.82
8.5	18,003,552	42,290	0.0023	0.9977	98.71
9.5	16,976,858	62,727	0.0037	0.9963	98.48
10.5	16,278,855	33,677	0.0021	0.9979	98.12
11.5	15,633,531	43,188	0.0028	0.9972	97.91
12.5	14,824,647	50,164	0.0034	0.9966	97.64
13.5	14,095,722	28,346	0.0020	0.9980	97.31
14.5	13,302,404	81,074	0.0061	0.9939	97.12
15.5	12,321,817	44,321	0.0036	0.9964	96.52
16.5	11,376,746	51,876	0.0046	0.9954	96.18
17.5	10,319,365	24,536	0.0024	0.9976	95.74
18.5	8,720,559	54,151	0.0062	0.9938	95.51
19.5	7,502,142	49,943	0.0067	0.9933	94.92
20.5	6,669,977	32,362	0.0049	0.9951	94.29
21.5	5,527,269	27,327	0.0049	0.9951	93.83
22.5	4,924,930	20,519	0.0042	0.9958	93.37
23.5	4,570,788	21,089	0.0046	0.9954	92.98
24.5	4,131,753	36,613	0.0089	0.9911	92.55
25.5	3,815,579	14,083	0.0037	0.9963	91.73
26.5	3,047,058	14,524	0.0048	0.9952	91.39
27.5	2,758,915	11,638	0.0042	0.9958	90.95
28.5	2,612,237	20,365	0.0078	0.9922	90.57
29.5	2,237,773	8,032	0.0036	0.9964	89.86
30.5	2,100,577	26,478	0.0126	0.9874	89.54
31.5	1,965,330	16,386	0.0083	0.9917	88.41
32.5	1,748,647	59,997	0.0343	0.9657	87.67
33.5	1,476,624	23,507	0.0159	0.9841	84.67
34.5	1,212,410	22,323	0.0184	0.9816	83.32
35.5	1,093,857	11,867	0.0108	0.9892	81.78
36.5	935,545	11,464	0.0123	0.9877	80.90
37.5	834,537	6,264	0.0075	0.9925	79.91
38.5	729,566	2,883	0.0040	0.9960	79.31

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	596,858	14,549	0.0244	0.9756	78.99
40.5	563,600	3,438	0.0061	0.9939	77.07
41.5	544,139	4,501	0.0083	0.9917	76.60
42.5	432,890	4,521	0.0104	0.9896	75.96
43.5	331,701	4,723	0.0142	0.9858	75.17
44.5	290,732	5,677	0.0195	0.9805	74.10
45.5	214,835	2,863	0.0133	0.9867	72.65
46.5	187,747	4,923	0.0262	0.9738	71.69
47.5	157,296	7,348	0.0467	0.9533	69.81
48.5	127,211	2,764	0.0217	0.9783	66.54
49.5	106,543	7,445	0.0699	0.9301	65.10
50.5	76,836	6,332	0.0824	0.9176	60.55
51.5	6,437		0.0000	1.0000	55.56
52.5	3,015		0.0000	1.0000	55.56
53.5					55.56

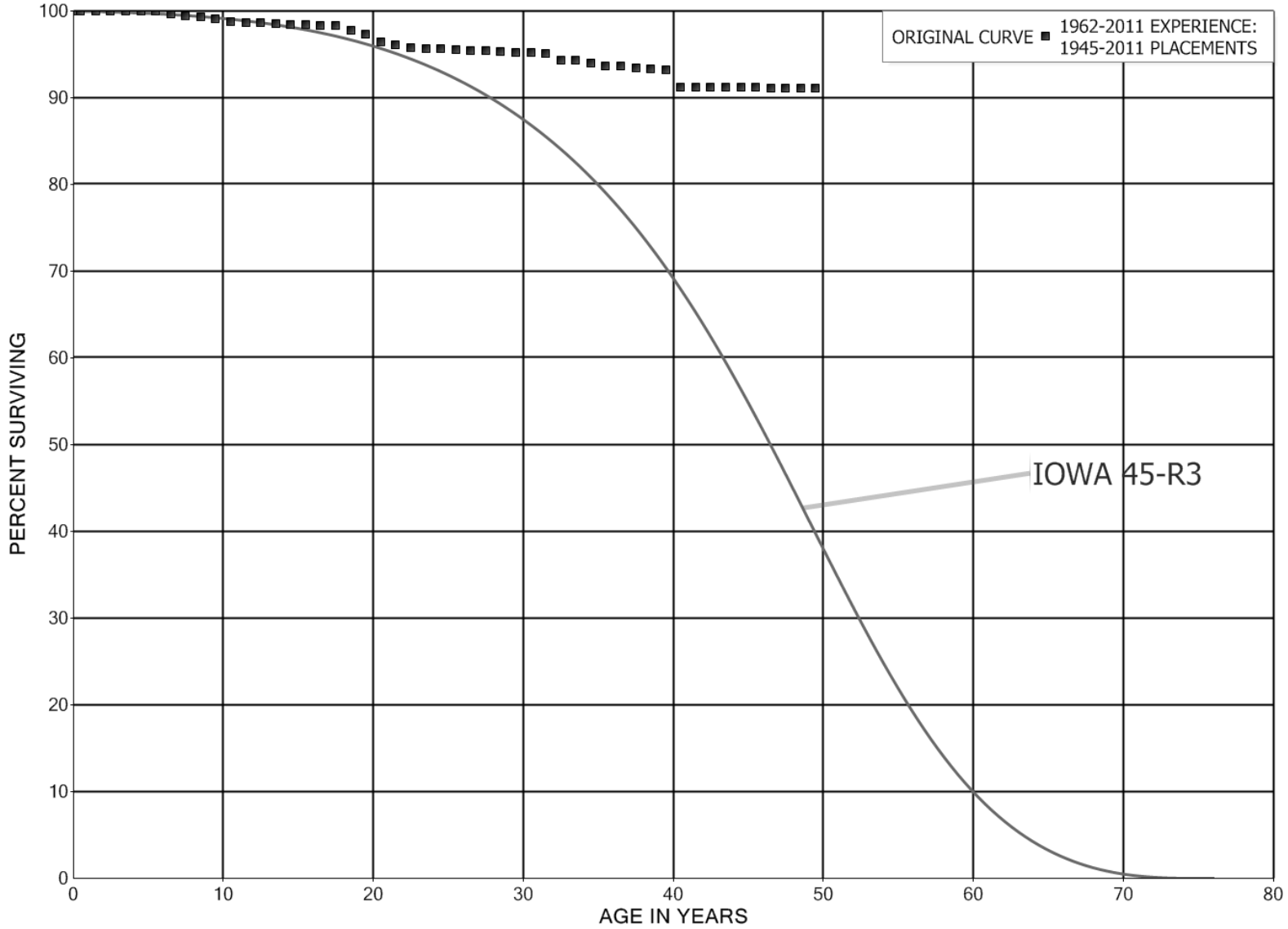

ORIGINAL CURVE
1960-2011 EXPERIENCE:
1945-2011 PLACEMENTS
IOWA 45-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	20,788,532	1,575	0.0001	0.9999	100.00
0.5	19,255,095	5,362	0.0003	0.9997	99.99
1.5	17,908,306	8,690	0.0005	0.9995	99.96
2.5	16,961,532	7,649	0.0005	0.9995	99.92
3.5	15,438,459	8,346	0.0005	0.9995	99.87
4.5	13,852,737	25,606	0.0018	0.9982	99.82
5.5	12,671,058	10,200	0.0008	0.9992	99.63
6.5	11,870,886	23,813	0.0020	0.9980	99.55
7.5	11,071,005	7,107	0.0006	0.9994	99.35
8.5	10,641,572	15,028	0.0014	0.9986	99.29
9.5	10,116,550	9,654	0.0010	0.9990	99.15
10.5	9,635,130	9,489	0.0010	0.9990	99.05
11.5	9,147,121	10,685	0.0012	0.9988	98.96
12.5	8,726,184	10,116	0.0012	0.9988	98.84
13.5	8,306,314	6,262	0.0008	0.9992	98.73
14.5	7,782,555	42,168	0.0054	0.9946	98.65
15.5	7,179,911	11,043	0.0015	0.9985	98.12
16.5	6,811,022	12,246	0.0018	0.9982	97.97
17.5	6,335,122	10,108	0.0016	0.9984	97.79
18.5	5,532,054	14,645	0.0026	0.9974	97.63
19.5	5,030,743	7,208	0.0014	0.9986	97.38
20.5	4,503,763	7,892	0.0018	0.9982	97.24
21.5	3,815,233	2,759	0.0007	0.9993	97.07
22.5	3,479,773	3,297	0.0009	0.9991	97.00
23.5	3,237,292	3,038	0.0009	0.9991	96.90
24.5	2,905,628	4,716	0.0016	0.9984	96.81
25.5	2,764,229	6,524	0.0024	0.9976	96.66
26.5	2,079,805	4,703	0.0023	0.9977	96.43
27.5	1,953,210	1,071	0.0005	0.9995	96.21
28.5	1,820,093	1,118	0.0006	0.9994	96.16
29.5	1,609,089	605	0.0004	0.9996	96.10
30.5	1,520,643	1,871	0.0012	0.9988	96.06
31.5	1,396,581	3,232	0.0023	0.9977	95.94
32.5	1,316,188	54,761	0.0416	0.9584	95.72
33.5	1,167,506	2,086	0.0018	0.9982	91.74
34.5	1,020,380	3,611	0.0035	0.9965	91.57
35.5	909,914	1,473	0.0016	0.9984	91.25
36.5	763,802	389	0.0005	0.9995	91.10
37.5	706,362	1,353	0.0019	0.9981	91.06
38.5	596,458	7	0.0000	1.0000	90.88

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	486,662	304	0.0006	0.9994	90.88
40.5	467,393	361	0.0008	0.9992	90.82
41.5	440,024	76	0.0002	0.9998	90.75
42.5	314,775	176	0.0006	0.9994	90.74
43.5	246,352	2,735	0.0111	0.9889	90.69
44.5	207,723	2,767	0.0133	0.9867	89.68
45.5	161,189	462	0.0029	0.9971	88.49
46.5	146,161		0.0000	1.0000	88.23
47.5	135,620		0.0000	1.0000	88.23
48.5	121,377	644	0.0053	0.9947	88.23
49.5	108,633	136	0.0013	0.9987	87.76
50.5	99,204	15	0.0002	0.9998	87.66
51.5	26,805	470	0.0175	0.9825	87.64
52.5	18,295		0.0000	1.0000	86.10
53.5	12,736		0.0000	1.0000	86.10
54.5	11,814	976	0.0826	0.9174	86.10
55.5	8,095	253	0.0313	0.9687	78.99
56.5	7,423		0.0000	1.0000	76.52
57.5	4,785		0.0000	1.0000	76.52
58.5	2,756		0.0000	1.0000	76.52
59.5	1,629		0.0000	1.0000	76.52
60.5	890		0.0000	1.0000	76.52
61.5	766	100	0.1307	0.8693	76.52
62.5	156	7	0.0450	0.9550	66.52
63.5					63.53

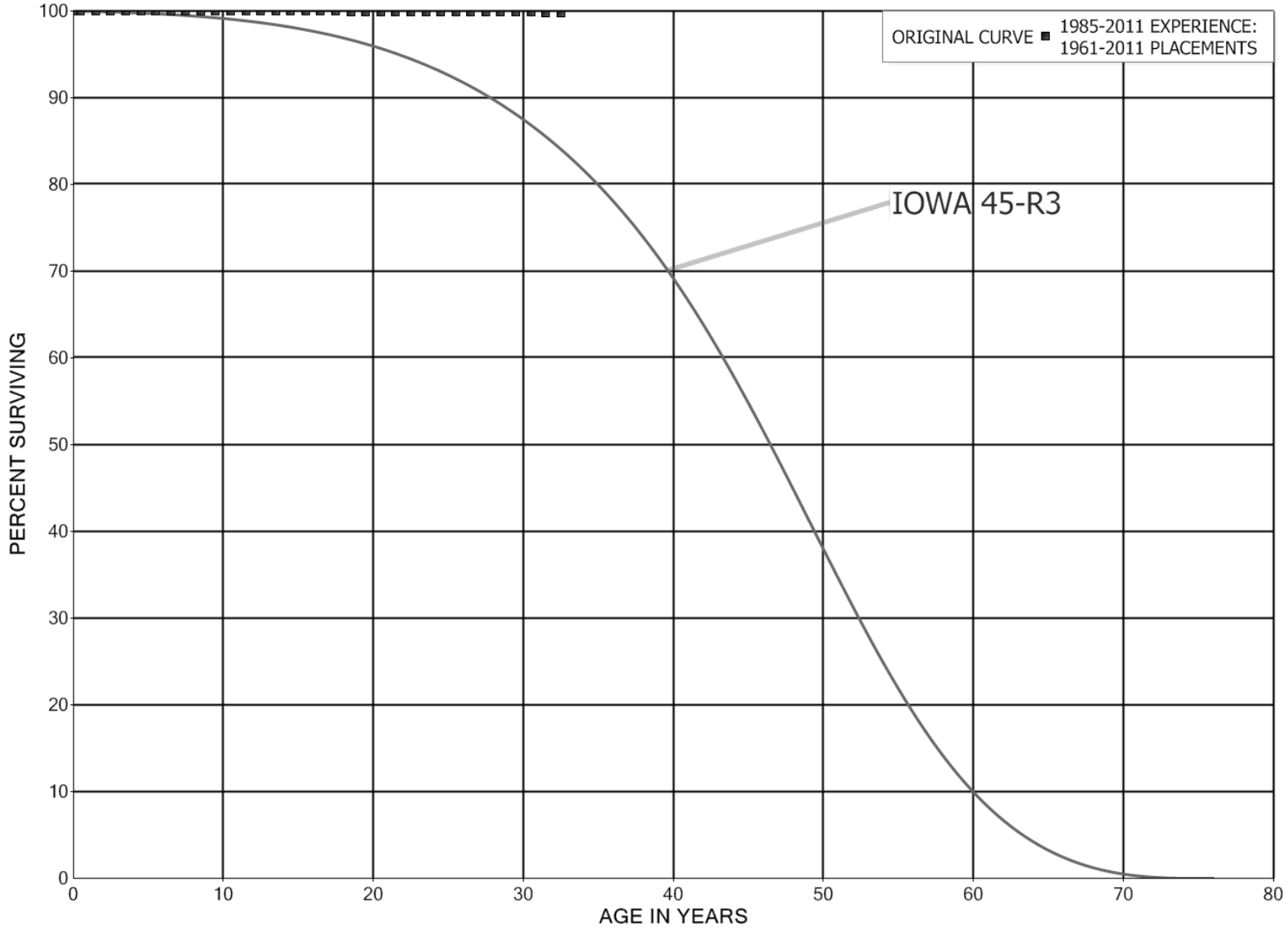

ORIGINAL CURVE
1962-2011 EXPERIENCE:
1945-2011 PLACEMENTS
IOWA 45-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1962-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,897,960		0.0000	1.0000	100.00
0.5	2,679,527	209	0.0001	0.9999	100.00
1.5	2,650,305	137	0.0001	0.9999	99.99
2.5	2,523,445	1,031	0.0004	0.9996	99.99
3.5	2,289,535	361	0.0002	0.9998	99.95
4.5	2,101,382	368	0.0002	0.9998	99.93
5.5	1,968,323	4,885	0.0025	0.9975	99.91
6.5	1,902,819	4,437	0.0023	0.9977	99.66
7.5	1,833,401	3,026	0.0017	0.9983	99.43
8.5	1,777,197	3,219	0.0018	0.9982	99.27
9.5	1,716,047	6,929	0.0040	0.9960	99.09
10.5	1,684,449	572	0.0003	0.9997	98.69
11.5	1,651,024	894	0.0005	0.9995	98.66
12.5	1,610,121	1,026	0.0006	0.9994	98.60
13.5	1,562,798	2,139	0.0014	0.9986	98.54
14.5	1,515,231	769	0.0005	0.9995	98.40
15.5	1,514,883	1,339	0.0009	0.9991	98.35
16.5	1,461,458	317	0.0002	0.9998	98.27
17.5	1,396,360	6,657	0.0048	0.9952	98.25
18.5	1,277,630	6,847	0.0054	0.9946	97.78
19.5	1,107,081	9,680	0.0087	0.9913	97.25
20.5	989,250	3,274	0.0033	0.9967	96.40
21.5	896,304	3,357	0.0037	0.9963	96.08
22.5	811,679	1,006	0.0012	0.9988	95.72
23.5	744,060	235	0.0003	0.9997	95.61
24.5	675,944	256	0.0004	0.9996	95.58
25.5	624,079	1,040	0.0017	0.9983	95.54
26.5	590,354	180	0.0003	0.9997	95.38
27.5	549,937	107	0.0002	0.9998	95.35
28.5	509,327	645	0.0013	0.9987	95.33
29.5	477,702	237	0.0005	0.9995	95.21
30.5	424,234	213	0.0005	0.9995	95.16
31.5	380,748	3,198	0.0084	0.9916	95.12
32.5	325,500	195	0.0006	0.9994	94.32
33.5	263,123	711	0.0027	0.9973	94.26
34.5	219,990	896	0.0041	0.9959	94.01
35.5	181,415		0.0000	1.0000	93.62
36.5	146,796	281	0.0019	0.9981	93.62
37.5	126,348	144	0.0011	0.9989	93.44
38.5	111,511	161	0.0014	0.9986	93.34

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1962-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	98,393	2,138	0.0217	0.9783	93.20
40.5	84,181	26	0.0003	0.9997	91.18
41.5	72,402		0.0000	1.0000	91.15
42.5	64,880		0.0000	1.0000	91.15
43.5	56,880		0.0000	1.0000	91.15
44.5	49,399		0.0000	1.0000	91.15
45.5	44,802	32	0.0007	0.9993	91.15
46.5	41,541		0.0000	1.0000	91.08
47.5	36,981		0.0000	1.0000	91.08
48.5	34,457		0.0000	1.0000	91.08
49.5	29,129	296	0.0102	0.9898	91.08
50.5	27,041		0.0000	1.0000	90.16
51.5	25,481		0.0000	1.0000	90.16
52.5	23,948		0.0000	1.0000	90.16
53.5	22,778		0.0000	1.0000	90.16
54.5	19,186		0.0000	1.0000	90.16
55.5	15,861		0.0000	1.0000	90.16
56.5	13,090		0.0000	1.0000	90.16
57.5	9,893		0.0000	1.0000	90.16
58.5	7,434		0.0000	1.0000	90.16
59.5	6,068		0.0000	1.0000	90.16
60.5	5,167		0.0000	1.0000	90.16
61.5	4,359		0.0000	1.0000	90.16
62.5	3,686		0.0000	1.0000	90.16
63.5	3,116		0.0000	1.0000	90.16
64.5	2,640		0.0000	1.0000	90.16
65.5	2,225	22	0.0099	0.9901	90.16
66.5					89.27

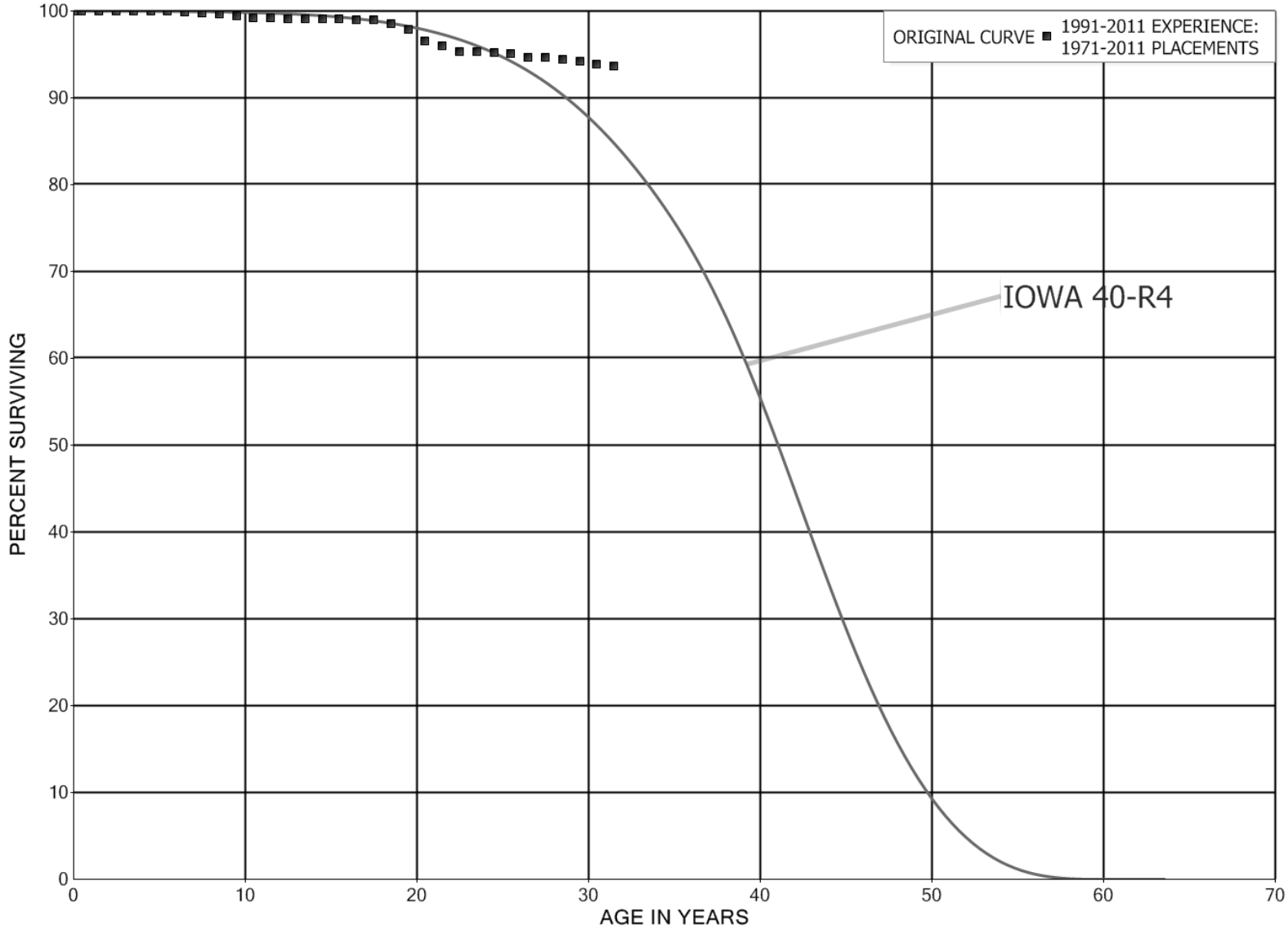

ORIGINAL CURVE
1985-2011 EXPERIENCE:
1961-2011 PLACEMENTS
IOWA 45-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1961-2011 EXPERIENCE BAND 1985-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,704,379	306	0.0000	1.0000	100.00
0.5	18,868,373	200	0.0000	1.0000	100.00
1.5	18,307,894	2,007	0.0001	0.9999	100.00
2.5	17,131,040	7	0.0000	1.0000	99.99
3.5	16,330,481	679	0.0000	1.0000	99.99
4.5	16,220,522	97	0.0000	1.0000	99.98
5.5	15,496,884	314	0.0000	1.0000	99.98
6.5	15,029,442	339	0.0000	1.0000	99.98
7.5	14,036,041		0.0000	1.0000	99.98
8.5	12,949,411	378	0.0000	1.0000	99.98
9.5	11,944,443	81	0.0000	1.0000	99.97
10.5	10,228,413	1,186	0.0001	0.9999	99.97
11.5	9,704,739	2,885	0.0003	0.9997	99.96
12.5	8,841,122	20	0.0000	1.0000	99.93
13.5	8,183,034		0.0000	1.0000	99.93
14.5	7,062,651	2,151	0.0003	0.9997	99.93
15.5	6,528,623	525	0.0001	0.9999	99.90
16.5	5,403,385	41	0.0000	1.0000	99.89
17.5	5,135,520	490	0.0001	0.9999	99.89
18.5	4,138,490	455	0.0001	0.9999	99.88
19.5	3,401,557	12	0.0000	1.0000	99.87
20.5	3,229,608	81	0.0000	1.0000	99.87
21.5	2,990,286	72	0.0000	1.0000	99.87
22.5	1,607,602	11	0.0000	1.0000	99.87
23.5	1,537,464	38	0.0000	1.0000	99.87
24.5	1,356,302	660	0.0005	0.9995	99.86
25.5	1,333,676	3	0.0000	1.0000	99.82
26.5	1,272,443		0.0000	1.0000	99.82
27.5	1,239,767		0.0000	1.0000	99.82
28.5	1,171,472	19	0.0000	1.0000	99.82
29.5	1,122,142	15	0.0000	1.0000	99.81
30.5	1,098,861	591	0.0005	0.9995	99.81
31.5	382,215	7	0.0000	1.0000	99.76
32.5	365,200	5	0.0000	1.0000	99.76
33.5	107,939		0.0000	1.0000	99.76
34.5	103,390		0.0000	1.0000	99.76
35.5	36,720		0.0000	1.0000	99.76
36.5	28,132		0.0000	1.0000	99.76
37.5	20,759		0.0000	1.0000	99.76
38.5	15,703		0.0000	1.0000	99.76

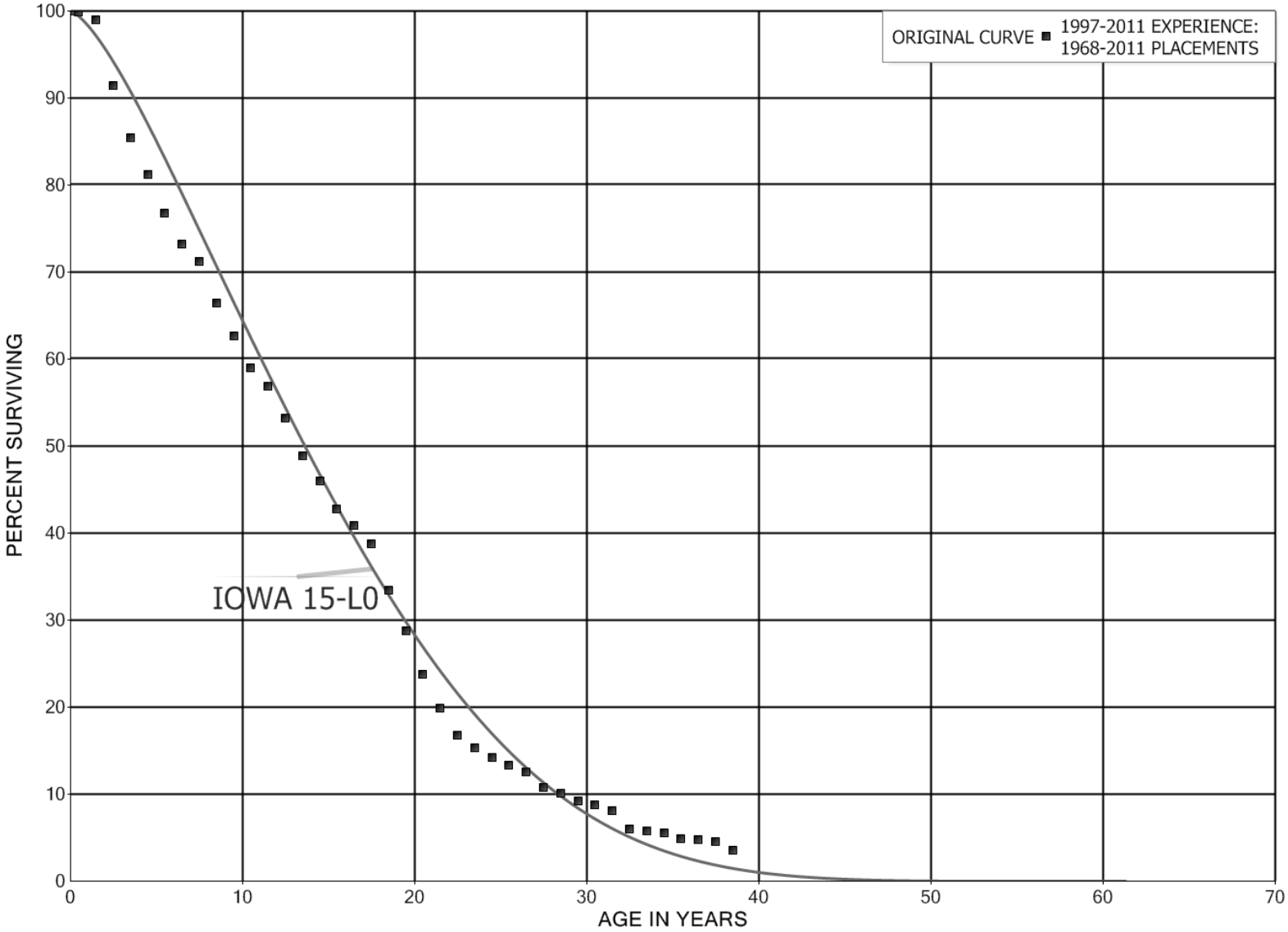
PLACEMENT BAND 1961-2011 EXPERIENCE BAND 1985-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,549		0.0000	1.0000	99.76
40.5	1,484		0.0000	1.0000	99.76
41.5	1,484		0.0000	1.0000	99.76
42.5	127		0.0000	1.0000	99.76
43.5	127		0.0000	1.0000	99.76
44.5	127		0.0000	1.0000	99.76
45.5	127		0.0000	1.0000	99.76
46.5	127		0.0000	1.0000	99.76
47.5	127		0.0000	1.0000	99.76
48.5	127		0.0000	1.0000	99.76
49.5	127	115	0.9055	0.0945	99.76
50.5					9.43


ORIGINAL CURVE
1991-2011 EXPERIENCE:
1971-2011 PLACEMENTS
IOWA 40-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70

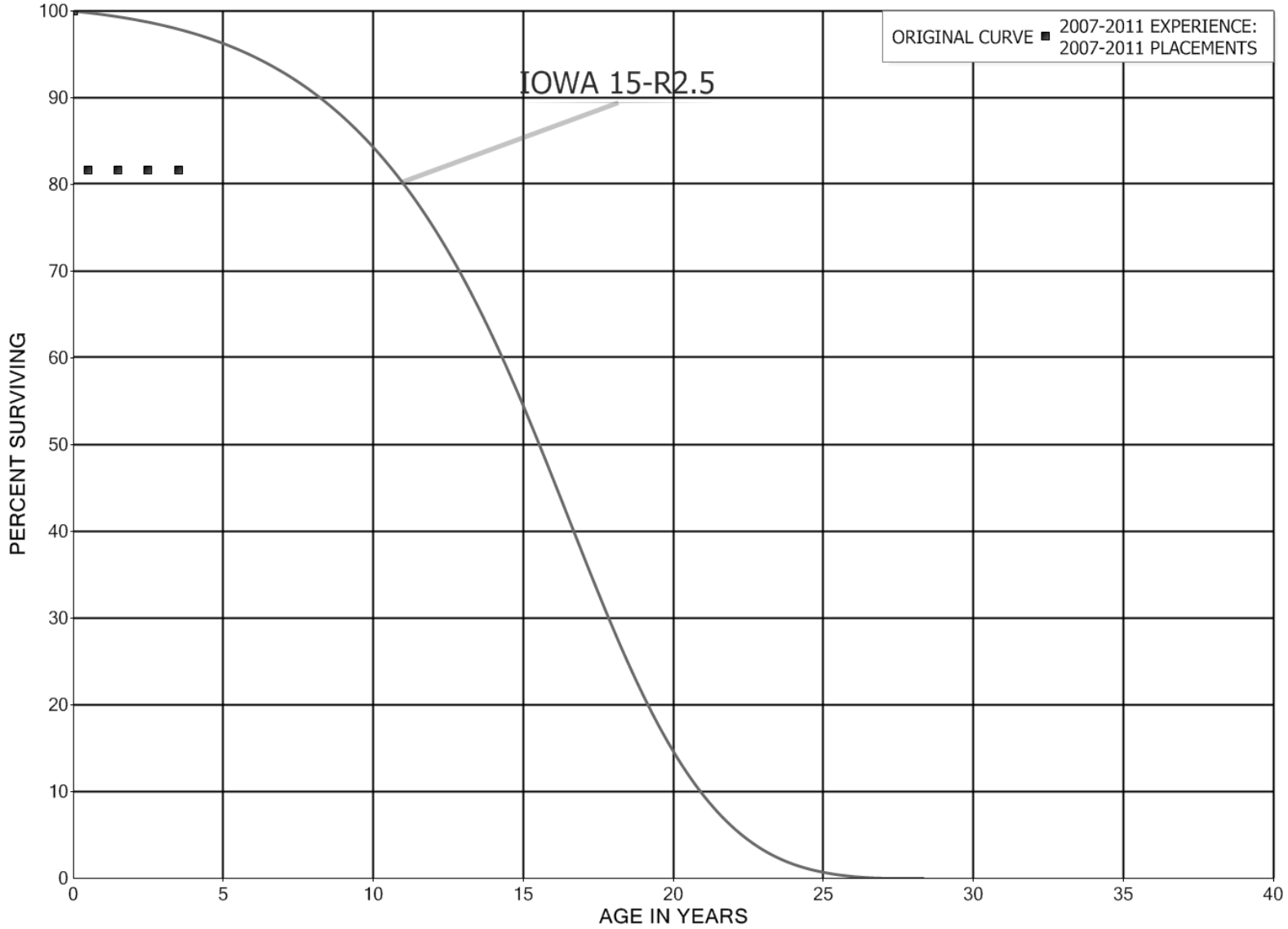
PLACEMENT BAND 1971-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,620,757		0.0000	1.0000	100.00
0.5	2,471,964	136	0.0001	0.9999	100.00
1.5	2,443,291	95	0.0000	1.0000	99.99
2.5	2,461,478	684	0.0003	0.9997	99.99
3.5	2,430,245	234	0.0001	0.9999	99.96
4.5	2,314,544	254	0.0001	0.9999	99.95
5.5	2,083,803	1,771	0.0008	0.9992	99.94
6.5	1,939,759	2,687	0.0014	0.9986	99.86
7.5	1,734,398	2,602	0.0015	0.9985	99.72
8.5	1,663,049	2,148	0.0013	0.9987	99.57
9.5	1,603,712	4,583	0.0029	0.9971	99.44
10.5	1,539,527	175	0.0001	0.9999	99.16
11.5	1,540,195	556	0.0004	0.9996	99.15
12.5	1,479,001	204	0.0001	0.9999	99.11
13.5	1,380,492	238	0.0002	0.9998	99.10
14.5	1,254,583	389	0.0003	0.9997	99.08
15.5	1,027,868	548	0.0005	0.9995	99.05
16.5	903,446	89	0.0001	0.9999	99.00
17.5	818,448	4,222	0.0052	0.9948	98.99
18.5	616,038	3,902	0.0063	0.9937	98.47
19.5	460,903	6,273	0.0136	0.9864	97.85
20.5	368,937	2,050	0.0056	0.9944	96.52
21.5	302,970	2,299	0.0076	0.9924	95.98
22.5	236,419	46	0.0002	0.9998	95.25
23.5	181,025	163	0.0009	0.9991	95.24
24.5	116,477	149	0.0013	0.9987	95.15
25.5	68,732	281	0.0041	0.9959	95.03
26.5	65,984	52	0.0008	0.9992	94.64
27.5	59,882	74	0.0012	0.9988	94.57
28.5	55,696	151	0.0027	0.9973	94.45
29.5	49,409	164	0.0033	0.9967	94.19
30.5	34,917	82	0.0024	0.9976	93.88
31.5	29,718	2,962	0.0997	0.9003	93.66
32.5	10,601	1,728	0.1630	0.8370	84.33
33.5	67		0.0000	1.0000	70.58
34.5	67		0.0000	1.0000	70.58
35.5	67		0.0000	1.0000	70.58
36.5	67		0.0000	1.0000	70.58
37.5	67		0.0000	1.0000	70.58
38.5	67	67	1.0000		70.58
39.5					


ORIGINAL CURVE
1997-2011 EXPERIENCE:
1968-2011 PLACEMENTS
IOWA 15-L0
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70

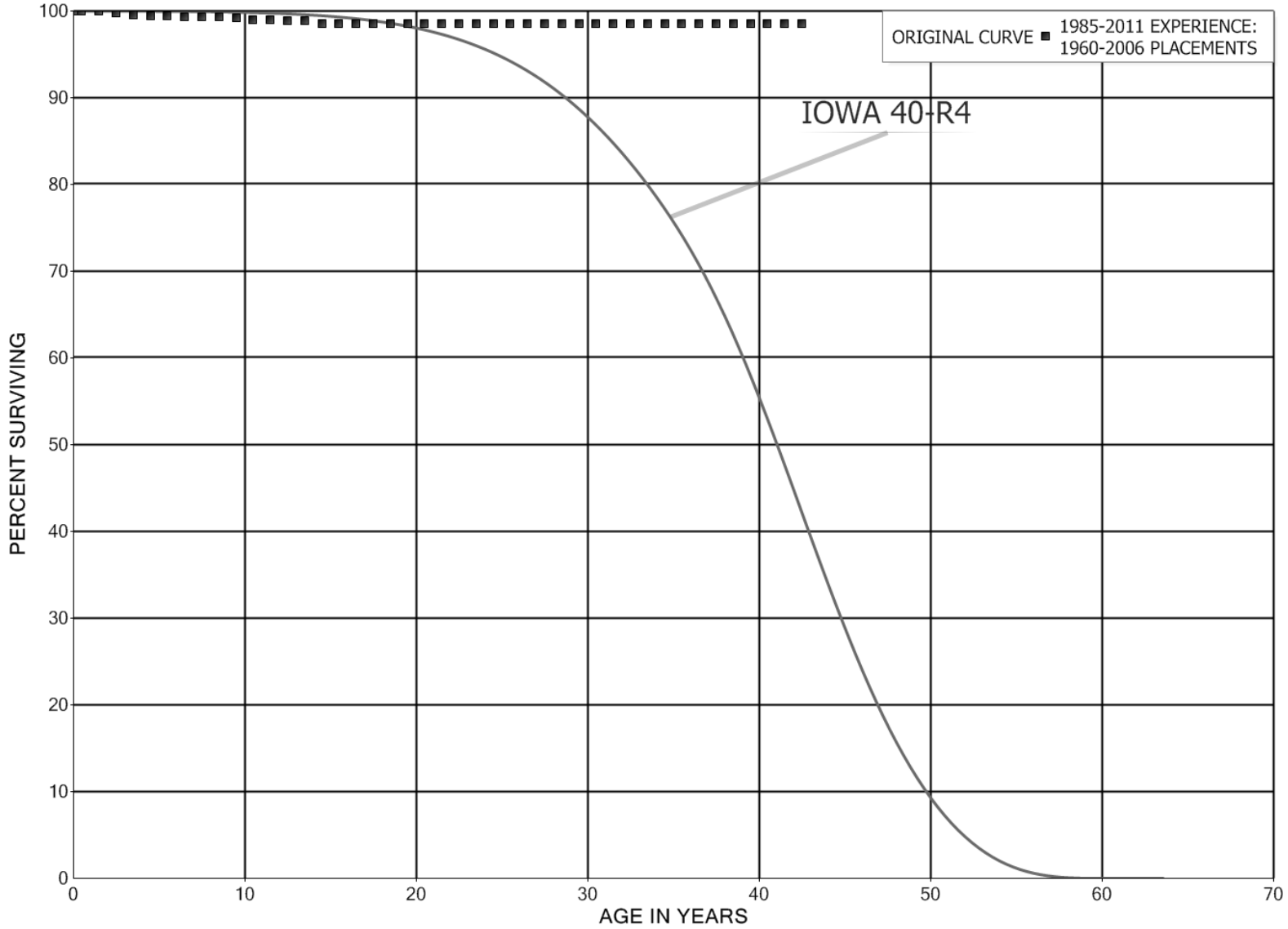
PLACEMENT BAND 1968-2011 EXPERIENCE BAND 1997-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,721,599	3,504	0.0020	0.9980	100.00
0.5	1,531,375	13,272	0.0087	0.9913	99.80
1.5	1,070,993	81,132	0.0758	0.9242	98.93
2.5	1,023,478	67,944	0.0664	0.9336	91.44
3.5	1,047,822	51,658	0.0493	0.9507	85.37
4.5	1,077,564	59,331	0.0551	0.9449	81.16
5.5	1,082,760	50,139	0.0463	0.9537	76.69
6.5	1,095,126	29,652	0.0271	0.9729	73.14
7.5	1,029,623	68,528	0.0666	0.9334	71.16
8.5	906,930	52,676	0.0581	0.9419	66.42
9.5	862,730	49,639	0.0575	0.9425	62.56
10.5	801,121	29,265	0.0365	0.9635	58.96
11.5	694,679	44,249	0.0637	0.9363	56.81
12.5	596,929	48,819	0.0818	0.9182	53.19
13.5	463,951	27,305	0.0589	0.9411	48.84
14.5	438,374	30,603	0.0698	0.9302	45.97
15.5	441,140	19,936	0.0452	0.9548	42.76
16.5	435,881	22,313	0.0512	0.9488	40.83
17.5	427,358	59,526	0.1393	0.8607	38.74
18.5	347,310	48,033	0.1383	0.8617	33.34
19.5	278,046	48,276	0.1736	0.8264	28.73
20.5	245,715	40,171	0.1635	0.8365	23.74
21.5	212,614	33,624	0.1581	0.8419	19.86
22.5	153,200	13,190	0.0861	0.9139	16.72
23.5	151,212	10,471	0.0692	0.9308	15.28
24.5	142,946	9,196	0.0643	0.9357	14.22
25.5	146,977	9,371	0.0638	0.9362	13.31
26.5	145,781	20,904	0.1434	0.8566	12.46
27.5	126,914	6,652	0.0524	0.9476	10.67
28.5	138,334	13,514	0.0977	0.9023	10.11
29.5	119,588	5,484	0.0459	0.9541	9.12
30.5	110,516	8,782	0.0795	0.9205	8.71
31.5	97,389	24,789	0.2545	0.7455	8.01
32.5	72,132	3,348	0.0464	0.9536	5.97
33.5	64,822	2,413	0.0372	0.9628	5.70
34.5	60,249	7,443	0.1235	0.8765	5.49
35.5	49,274	1,406	0.0285	0.9715	4.81
36.5	37,476	1,057	0.0282	0.9718	4.67
37.5	35,353	7,984	0.2258	0.7742	4.54
38.5	22,447	1,847	0.0823	0.9177	3.51
39.5	16,441	11,964	0.7277	0.2723	3.22
40.5	184	166	0.9015	0.0985	0.88
41.5					0.09


IOWA 15-R2.5
ORIGINAL CURVE
2007-2011 EXPERIENCE:
2007-2011 PLACEMENTS
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40

PLACEMENT BAND 2007-2011 EXPERIENCE BAND 2007-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	78,825	14,525	0.1843	0.8157	100.00
0.5	62,588		0.0000	1.0000	81.57
1.5	49,447		0.0000	1.0000	81.57
2.5	37,215		0.0000	1.0000	81.57
3.5	7,790		0.0000	1.0000	81.57
4.5					81.57

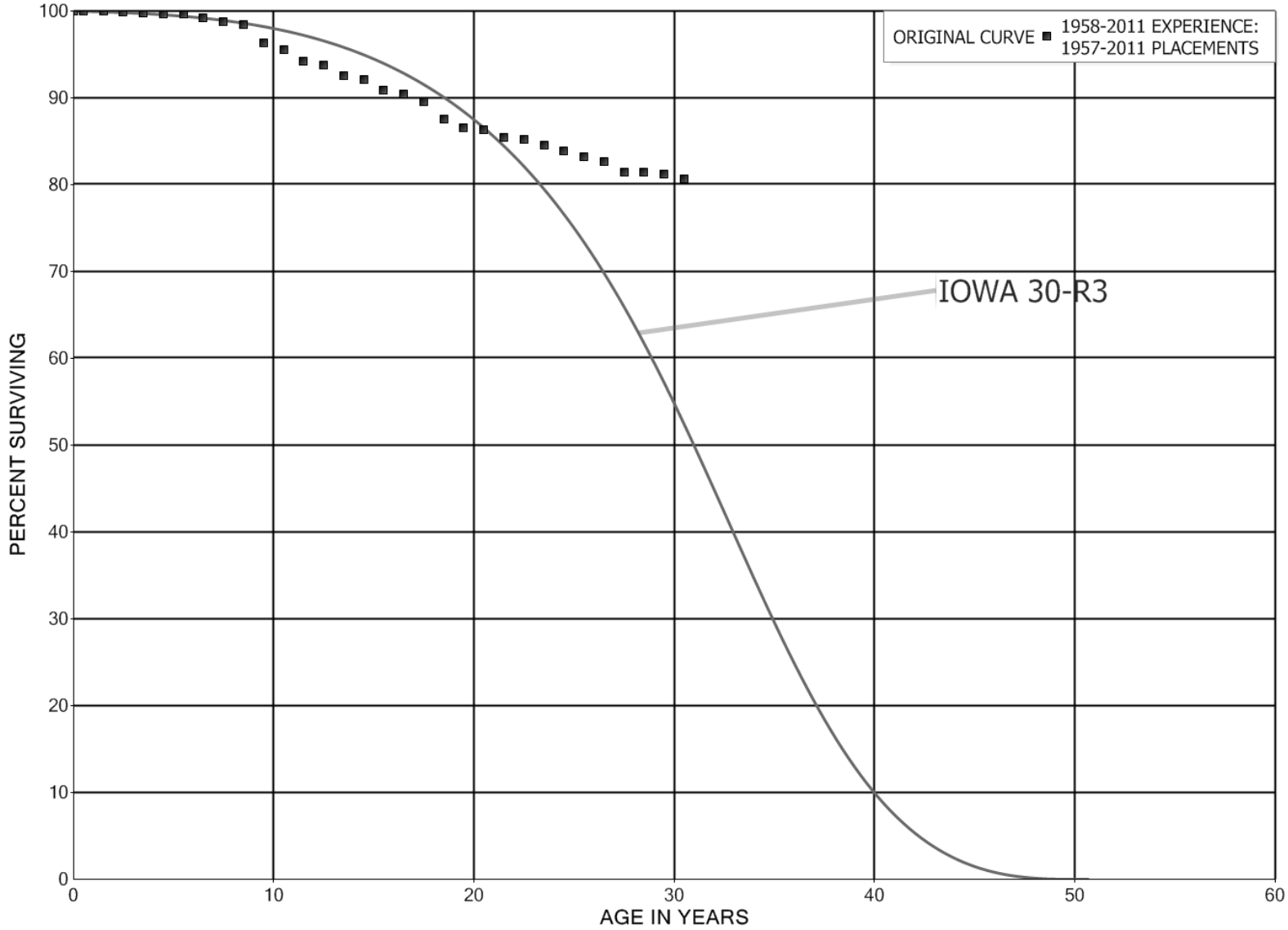

ORIGINAL CURVE
1985-2011 EXPERIENCE:
1960-2006 PLACEMENTS
IOWA 40-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70

PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1985-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,726,576		0.0000	1.0000	100.00
0.5	2,401,558	211	0.0001	0.9999	100.00
1.5	2,401,347	5,152	0.0021	0.9979	99.99
2.5	2,396,194	7,649	0.0032	0.9968	99.78
3.5	2,515,590	786	0.0003	0.9997	99.46
4.5	2,603,775	2,182	0.0008	0.9992	99.43
5.5	2,594,208	723	0.0003	0.9997	99.34
6.5	2,101,778		0.0000	1.0000	99.32
7.5	2,174,234		0.0000	1.0000	99.32
8.5	2,507,476	4,215	0.0017	0.9983	99.32
9.5	2,504,858	6,207	0.0025	0.9975	99.15
10.5	2,252,210		0.0000	1.0000	98.90
11.5	2,229,667	1,638	0.0007	0.9993	98.90
12.5	2,184,787		0.0000	1.0000	98.83
13.5	2,224,755	6,267	0.0028	0.9972	98.83
14.5	2,217,118	90	0.0000	1.0000	98.55
15.5	2,021,818	1,182	0.0006	0.9994	98.55
16.5	2,037,242		0.0000	1.0000	98.49
17.5	1,995,561	176	0.0001	0.9999	98.49
18.5	1,828,451		0.0000	1.0000	98.48
19.5	1,729,873		0.0000	1.0000	98.48
20.5	1,469,952		0.0000	1.0000	98.48
21.5	1,337,752		0.0000	1.0000	98.48
22.5	1,301,170		0.0000	1.0000	98.48
23.5	1,240,263		0.0000	1.0000	98.48
24.5	908,097		0.0000	1.0000	98.48
25.5	789,781		0.0000	1.0000	98.48
26.5	746,259		0.0000	1.0000	98.48
27.5	746,259		0.0000	1.0000	98.48
28.5	746,259		0.0000	1.0000	98.48
29.5	746,259		0.0000	1.0000	98.48
30.5	619,929		0.0000	1.0000	98.48
31.5	539,094		0.0000	1.0000	98.48
32.5	524,140		0.0000	1.0000	98.48
33.5	524,140		0.0000	1.0000	98.48
34.5	453,256		0.0000	1.0000	98.48
35.5	120,164		0.0000	1.0000	98.48
36.5	120,164		0.0000	1.0000	98.48
37.5	119,718		0.0000	1.0000	98.48
38.5	63,168		0.0000	1.0000	98.48

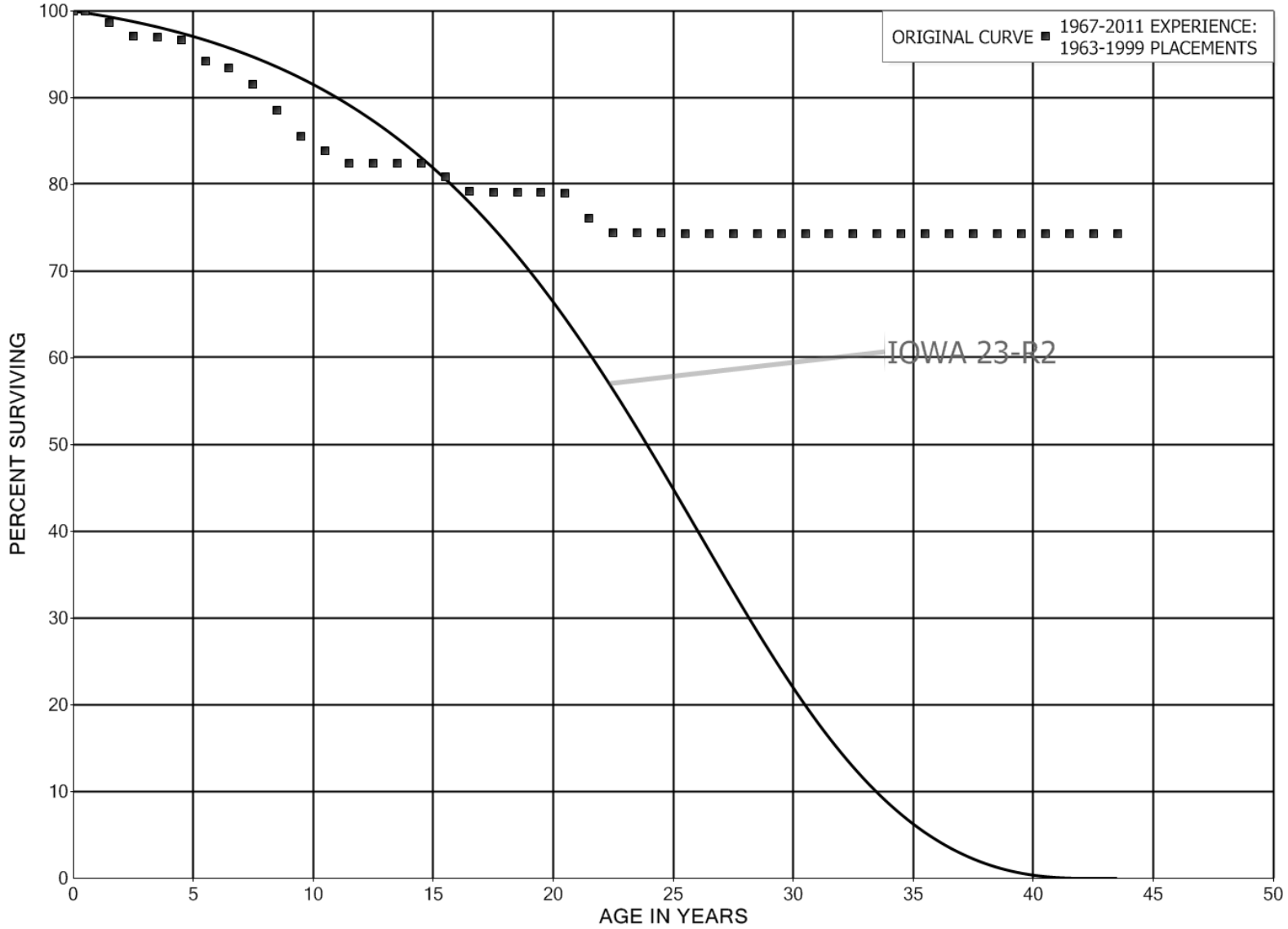
PLACEMENT BAND 1960-2006 EXPERIENCE BAND 1985-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	61,079		0.0000	1.0000	98.48
40.5	21,120		0.0000	1.0000	98.48
41.5	21,120		0.0000	1.0000	98.48
42.5	20,238		0.0000	1.0000	98.48
43.5	3,632		0.0000	1.0000	98.48
44.5	3,632		0.0000	1.0000	98.48
45.5	3,632		0.0000	1.0000	98.48
46.5	3,632		0.0000	1.0000	98.48
47.5	3,632		0.0000	1.0000	98.48
48.5	3,632		0.0000	1.0000	98.48
49.5	3,632		0.0000	1.0000	98.48
50.5	3,632		0.0000	1.0000	98.48
51.5					98.48


ORIGINAL CURVE
1958-2011 EXPERIENCE:
1957-2011 PLACEMENTS
IOWA 30-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60

PLACEMENT BAND 1957-2011 EXPERIENCE BAND 1958-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,842,476	1,271	0.0001	0.9999	100.00
0.5	9,383,230	6,132	0.0007	0.9993	99.99
1.5	9,182,075	11,841	0.0013	0.9987	99.92
2.5	8,585,083	2,754	0.0003	0.9997	99.79
3.5	8,364,298	8,118	0.0010	0.9990	99.76
4.5	7,831,564	6,625	0.0008	0.9992	99.66
5.5	7,024,946	26,358	0.0038	0.9962	99.58
6.5	6,889,532	29,966	0.0043	0.9957	99.21
7.5	6,354,839	24,352	0.0038	0.9962	98.77
8.5	5,742,293	121,079	0.0211	0.9789	98.40
9.5	5,425,679	48,608	0.0090	0.9910	96.32
10.5	5,020,513	67,908	0.0135	0.9865	95.46
11.5	4,742,405	21,903	0.0046	0.9954	94.17
12.5	4,469,160	57,860	0.0129	0.9871	93.73
13.5	4,193,540	20,962	0.0050	0.9950	92.52
14.5	3,758,700	49,070	0.0131	0.9869	92.06
15.5	3,602,407	16,853	0.0047	0.9953	90.85
16.5	3,275,025	33,875	0.0103	0.9897	90.43
17.5	2,993,862	64,747	0.0216	0.9784	89.49
18.5	2,575,313	32,421	0.0126	0.9874	87.56
19.5	2,453,096	4,945	0.0020	0.9980	86.46
20.5	2,225,813	22,546	0.0101	0.9899	86.28
21.5	1,931,883	4,769	0.0025	0.9975	85.41
22.5	1,354,352	11,558	0.0085	0.9915	85.20
23.5	1,132,832	8,300	0.0073	0.9927	84.47
24.5	987,380	8,065	0.0082	0.9918	83.85
25.5	630,699	4,529	0.0072	0.9928	83.17
26.5	596,975	8,560	0.0143	0.9857	82.57
27.5	489,934	127	0.0003	0.9997	81.39
28.5	375,818	1,046	0.0028	0.9972	81.36
29.5	305,222	2,119	0.0069	0.9931	81.14
30.5	274,615	5,083	0.0185	0.9815	80.57
31.5	84,881	372	0.0044	0.9956	79.08
32.5	69,037	99	0.0014	0.9986	78.74
33.5	46,678		0.0000	1.0000	78.62
34.5	4,288		0.0000	1.0000	78.62
35.5	4,288		0.0000	1.0000	78.62
36.5	4,058		0.0000	1.0000	78.62
37.5					78.62

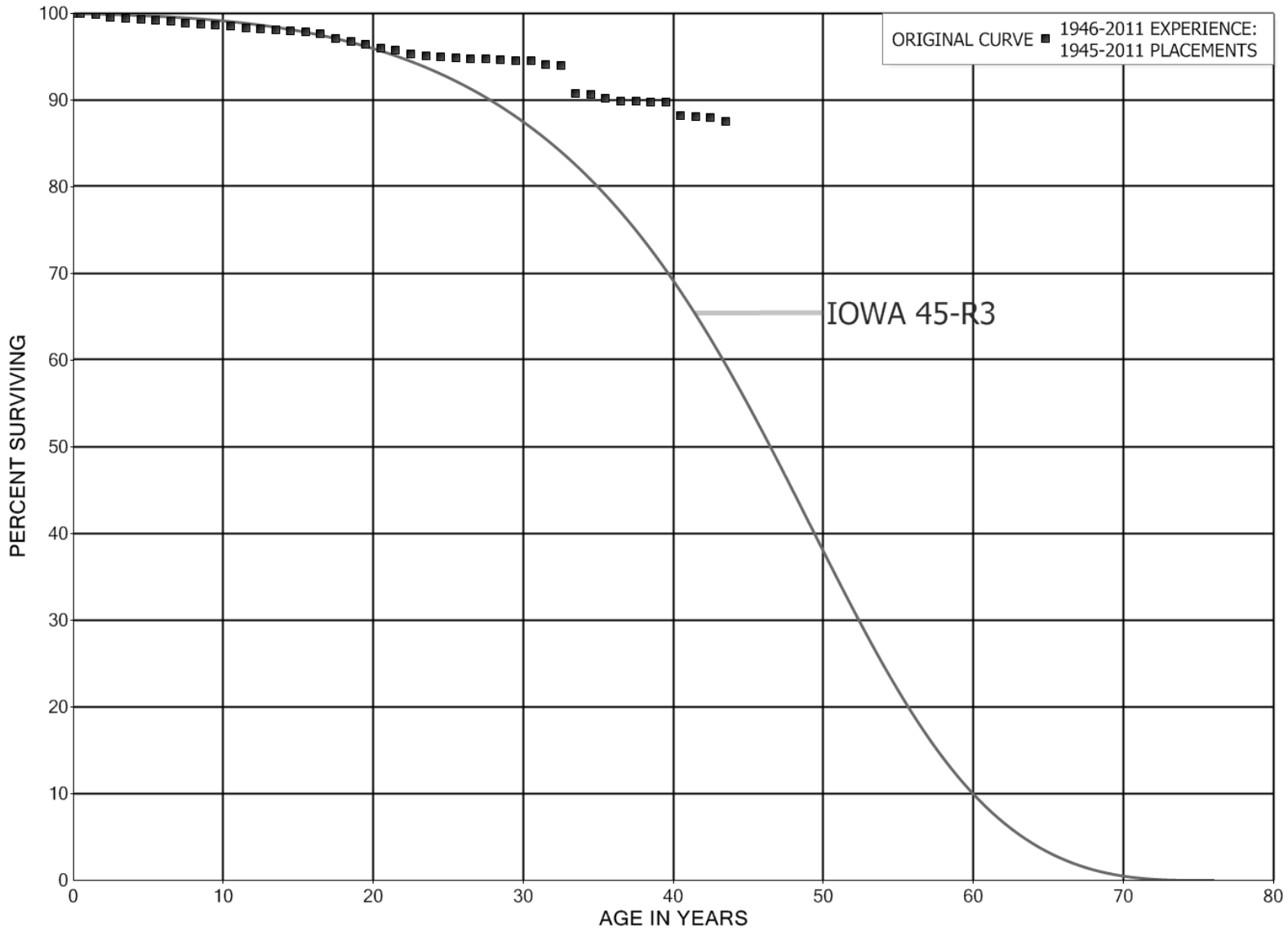

ORIGINAL CURVE
1967-2011 EXPERIENCE:
1963-1999 PLACEMENTS
IOWA 23-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40
45
50

PLACEMENT BAND 1963-1999 EXPERIENCE BAND 1967-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	362,351		0.0000	1.0000	100.00
0.5	365,415	5,205	0.0142	0.9858	100.00
1.5	364,074	5,705	0.0157	0.9843	98.58
2.5	368,538	90	0.0002	0.9998	97.03
3.5	368,660	1,359	0.0037	0.9963	97.01
4.5	367,301	9,199	0.0250	0.9750	96.65
5.5	358,102	3,074	0.0086	0.9914	94.23
6.5	355,028	7,104	0.0200	0.9800	93.42
7.5	347,924	11,746	0.0338	0.9662	91.55
8.5	336,178	11,318	0.0337	0.9663	88.46
9.5	324,860	6,348	0.0195	0.9805	85.48
10.5	318,512	5,466	0.0172	0.9828	83.81
11.5	313,046		0.0000	1.0000	82.37
12.5	312,597		0.0000	1.0000	82.37
13.5	312,597		0.0000	1.0000	82.37
14.5	296,725	5,706	0.0192	0.9808	82.37
15.5	291,019	5,978	0.0205	0.9795	80.79
16.5	285,041	55	0.0002	0.9998	79.13
17.5	284,986		0.0000	1.0000	79.11
18.5	284,834		0.0000	1.0000	79.11
19.5	274,249	374	0.0014	0.9986	79.11
20.5	271,312	10,247	0.0378	0.9622	79.01
21.5	257,736	5,540	0.0215	0.9785	76.02
22.5	244,805		0.0000	1.0000	74.39
23.5	231,309		0.0000	1.0000	74.39
24.5	217,097	407	0.0019	0.9981	74.39
25.5	184,777		0.0000	1.0000	74.25
26.5	174,248		0.0000	1.0000	74.25
27.5	155,180		0.0000	1.0000	74.25
28.5	144,345		0.0000	1.0000	74.25
29.5	135,210		0.0000	1.0000	74.25
30.5	118,173		0.0000	1.0000	74.25
31.5	99,203		0.0000	1.0000	74.25
32.5	69,882		0.0000	1.0000	74.25
33.5	53,809		0.0000	1.0000	74.25
34.5	43,269		0.0000	1.0000	74.25
35.5	28,416		0.0000	1.0000	74.25
36.5	23,662		0.0000	1.0000	74.25
37.5	3,987		0.0000	1.0000	74.25
38.5	2,516		0.0000	1.0000	74.25

PLACEMENT BAND 1963-1999 EXPERIENCE BAND 1967-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,516		0.0000	1.0000	74.25
40.5	2,516		0.0000	1.0000	74.25
41.5	2,516		0.0000	1.0000	74.25
42.5	2,516		0.0000	1.0000	74.25
43.5	2,516		0.0000	1.0000	74.25
44.5					74.25

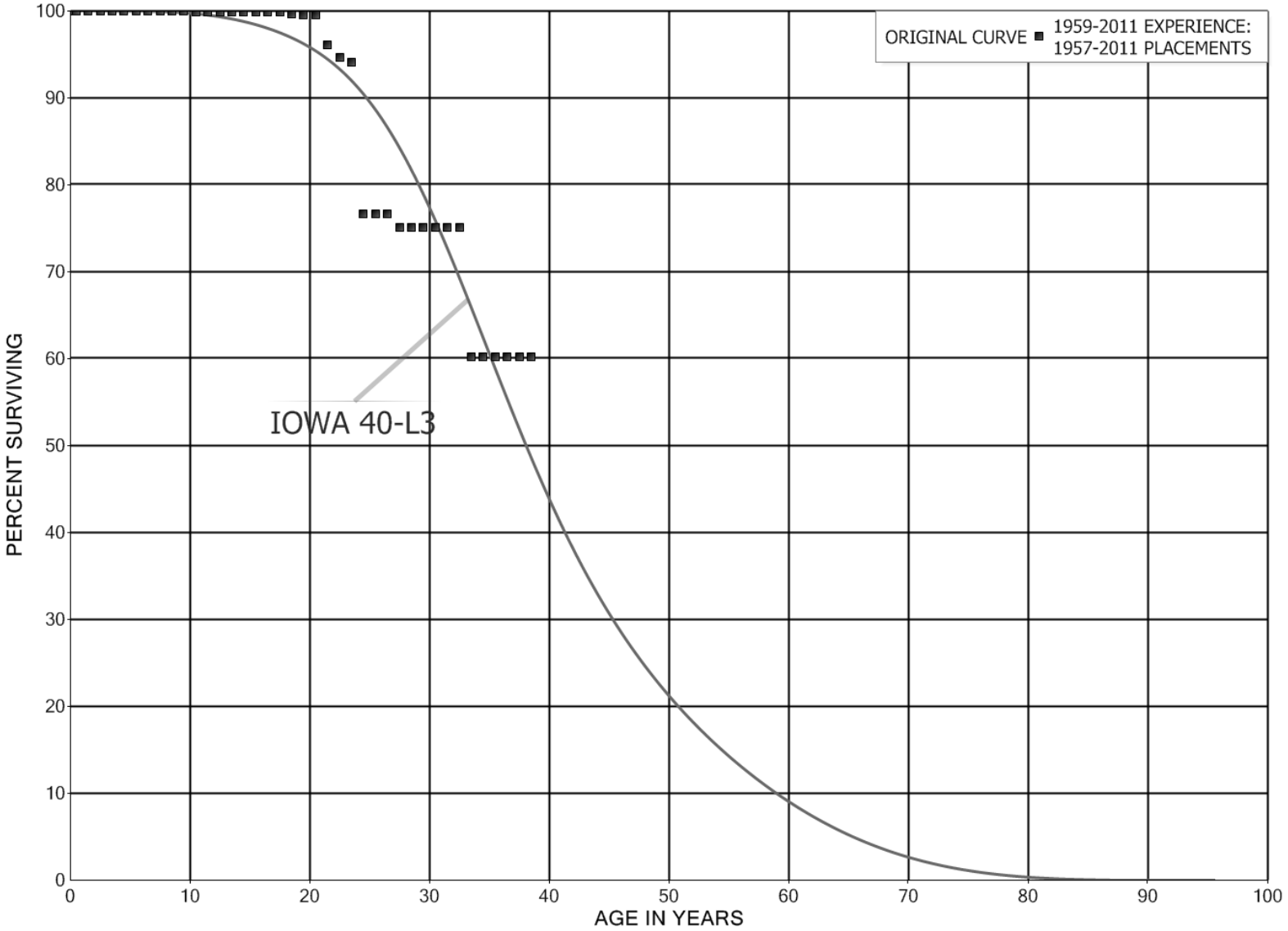

ORIGINAL CURVE
1946-2011 EXPERIENCE:
1945-2011 PLACEMENTS
IOWA 45-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1946-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,052,873	16,453	0.0007	0.9993	100.00
0.5	23,310,374	34,729	0.0015	0.9985	99.93
1.5	21,775,170	67,595	0.0031	0.9969	99.79
2.5	20,041,568	15,739	0.0008	0.9992	99.48
3.5	18,076,610	19,387	0.0011	0.9989	99.40
4.5	16,475,987	14,546	0.0009	0.9991	99.29
5.5	14,937,417	26,617	0.0018	0.9982	99.20
6.5	13,545,746	23,773	0.0018	0.9982	99.03
7.5	12,786,466	11,421	0.0009	0.9991	98.85
8.5	12,036,297	23,092	0.0019	0.9981	98.76
9.5	11,477,631	14,118	0.0012	0.9988	98.57
10.5	10,892,446	21,867	0.0020	0.9980	98.45
11.5	10,282,359	8,650	0.0008	0.9992	98.26
12.5	9,904,990	9,475	0.0010	0.9990	98.17
13.5	9,400,530	13,990	0.0015	0.9985	98.08
14.5	8,902,665	9,311	0.0010	0.9990	97.93
15.5	8,237,401	15,739	0.0019	0.9981	97.83
16.5	7,751,251	48,338	0.0062	0.9938	97.64
17.5	7,198,786	21,003	0.0029	0.9971	97.04
18.5	6,236,497	25,561	0.0041	0.9959	96.75
19.5	5,439,976	25,680	0.0047	0.9953	96.36
20.5	4,647,183	9,685	0.0021	0.9979	95.90
21.5	3,911,785	17,405	0.0044	0.9956	95.70
22.5	3,409,109	8,040	0.0024	0.9976	95.28
23.5	3,094,937	1,707	0.0006	0.9994	95.05
24.5	2,587,632	3,208	0.0012	0.9988	95.00
25.5	2,379,299	3,409	0.0014	0.9986	94.88
26.5	2,173,363	1,677	0.0008	0.9992	94.74
27.5	2,114,074	1,207	0.0006	0.9994	94.67
28.5	2,046,944	1,286	0.0006	0.9994	94.62
29.5	1,920,486	411	0.0002	0.9998	94.56
30.5	1,734,730	8,812	0.0051	0.9949	94.54
31.5	1,534,477	1,629	0.0011	0.9989	94.06
32.5	1,341,755	46,399	0.0346	0.9654	93.96
33.5	1,153,538	1,809	0.0016	0.9984	90.71
34.5	1,058,214	4,176	0.0039	0.9961	90.57
35.5	983,371	4,029	0.0041	0.9959	90.21
36.5	874,089	561	0.0006	0.9994	89.84
37.5	804,289	844	0.0010	0.9990	89.78
38.5	736,151	35	0.0000	1.0000	89.69

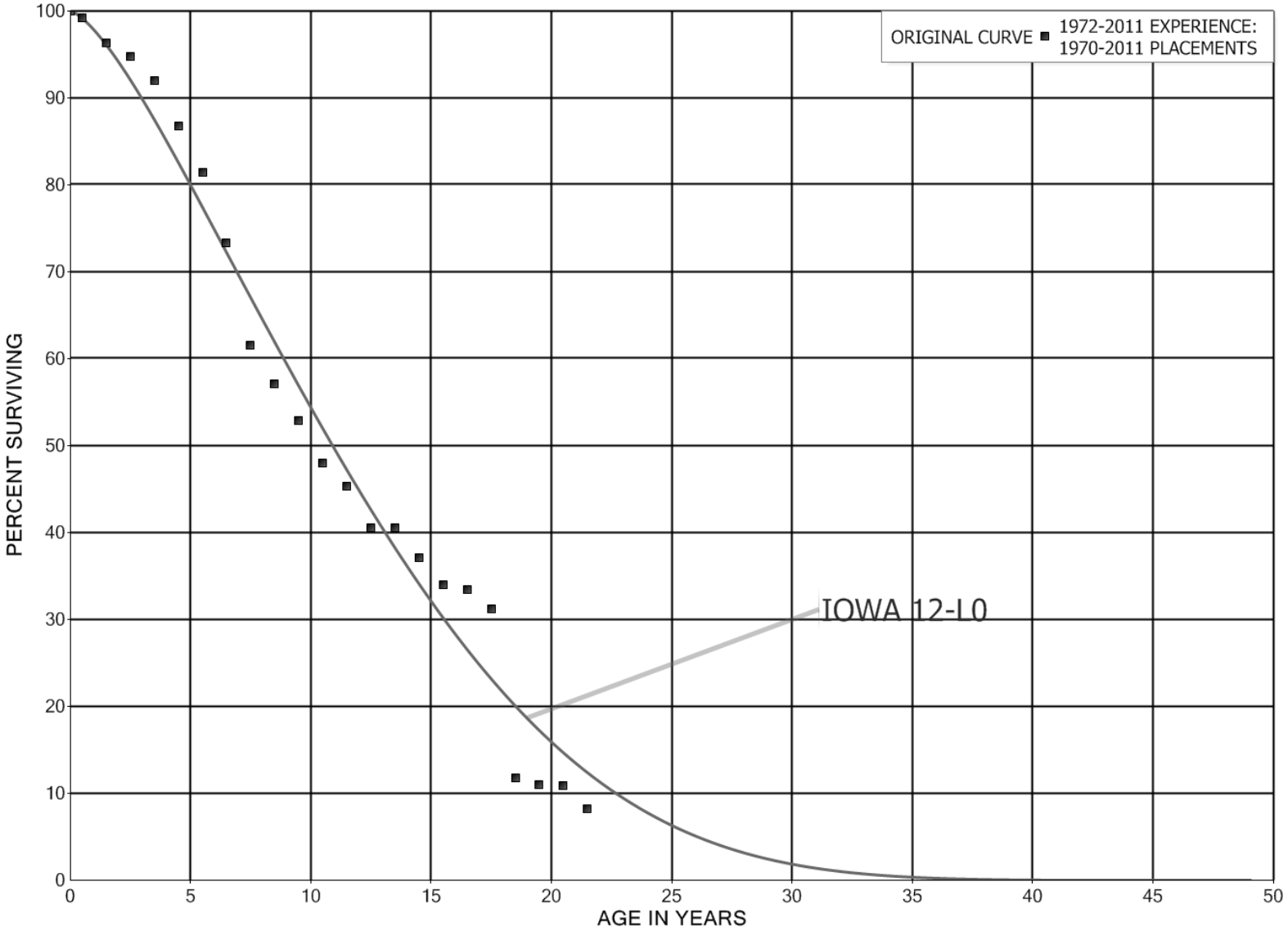
PLACEMENT BAND 1945-2011 EXPERIENCE BAND 1946-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	658,012	11,272	0.0171	0.9829	89.68
40.5	578,763	853	0.0015	0.9985	88.15
41.5	530,268	529	0.0010	0.9990	88.02
42.5	491,894	2,113	0.0043	0.9957	87.93
43.5	311,251	240	0.0008	0.9992	87.55
44.5	248,541	2,381	0.0096	0.9904	87.48
45.5	209,571		0.0000	1.0000	86.65
46.5	195,844		0.0000	1.0000	86.65
47.5	188,849		0.0000	1.0000	86.65
48.5	164,319	192	0.0012	0.9988	86.65
49.5	154,691	1,150	0.0074	0.9926	86.54
50.5	142,719		0.0000	1.0000	85.90
51.5	105,661		0.0000	1.0000	85.90
52.5	86,935		0.0000	1.0000	85.90
53.5	84,680	9,005	0.1063	0.8937	85.90
54.5	75,675	1,552	0.0205	0.9795	76.77
55.5	70,394		0.0000	1.0000	75.19
56.5	49,068	1,343	0.0274	0.9726	75.19
57.5	42,271		0.0000	1.0000	73.13
58.5	39,513		0.0000	1.0000	73.13
59.5	18,613		0.0000	1.0000	73.13
60.5	3,115		0.0000	1.0000	73.13
61.5	3,086		0.0000	1.0000	73.13
62.5	3,086		0.0000	1.0000	73.13
63.5	1,469		0.0000	1.0000	73.13
64.5	226		0.0000	1.0000	73.13
65.5					73.13


ORIGINAL CURVE
1959-2011 EXPERIENCE:
1957-2011 PLACEMENTS
IOWA 40-L3
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

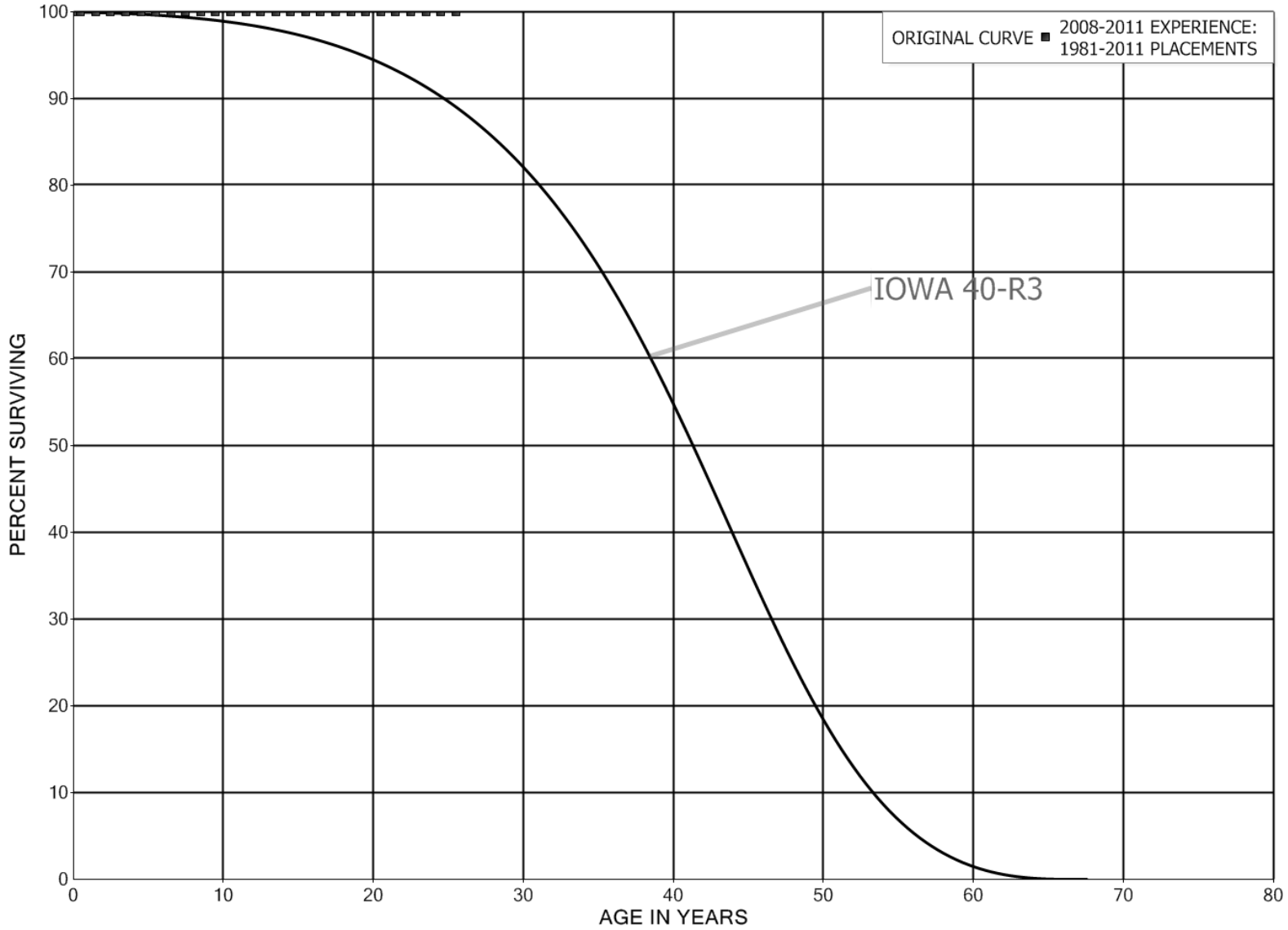
PLACEMENT BAND 1957-2011 EXPERIENCE BAND 1959-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,973,674		0.0000	1.0000	100.00
0.5	3,611,105		0.0000	1.0000	100.00
1.5	3,537,756		0.0000	1.0000	100.00
2.5	3,463,198		0.0000	1.0000	100.00
3.5	3,387,166		0.0000	1.0000	100.00
4.5	3,374,629		0.0000	1.0000	100.00
5.5	3,290,987		0.0000	1.0000	100.00
6.5	3,287,697		0.0000	1.0000	100.00
7.5	3,239,027		0.0000	1.0000	100.00
8.5	3,192,142	3,305	0.0010	0.9990	100.00
9.5	3,163,395	258	0.0001	0.9999	99.90
10.5	3,115,633		0.0000	1.0000	99.89
11.5	3,064,702		0.0000	1.0000	99.89
12.5	3,055,682		0.0000	1.0000	99.89
13.5	2,972,107	1,089	0.0004	0.9996	99.89
14.5	2,915,288		0.0000	1.0000	99.85
15.5	2,889,512		0.0000	1.0000	99.85
16.5	2,855,910	1,586	0.0006	0.9994	99.85
17.5	2,795,475	4,237	0.0015	0.9985	99.80
18.5	2,673,649	2,788	0.0010	0.9990	99.65
19.5	2,369,876	2,019	0.0009	0.9991	99.54
20.5	943,424	31,722	0.0336	0.9664	99.46
21.5	866,449	13,273	0.0153	0.9847	96.11
22.5	849,676	5,188	0.0061	0.9939	94.64
23.5	756,631	140,247	0.1854	0.8146	94.06
24.5	237,188		0.0000	1.0000	76.63
25.5	234,410		0.0000	1.0000	76.63
26.5	234,410	4,613	0.0197	0.9803	76.63
27.5	205,512		0.0000	1.0000	75.12
28.5	205,512		0.0000	1.0000	75.12
29.5	183,806	230	0.0013	0.9987	75.12
30.5	171,114		0.0000	1.0000	75.02
31.5	171,114		0.0000	1.0000	75.02
32.5	156,307	30,940	0.1979	0.8021	75.02
33.5	125,367		0.0000	1.0000	60.17
34.5	124,352		0.0000	1.0000	60.17
35.5	122,852		0.0000	1.0000	60.17
36.5	122,852		0.0000	1.0000	60.17
37.5	76,117		0.0000	1.0000	60.17
38.5	59,482		0.0000	1.0000	60.17
39.5					60.17


ORIGINAL CURVE
1972-2011 EXPERIENCE:
1970-2011 PLACEMENTS
IOWA 12-L0
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40
45
50

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1972-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,388,479	42,131	0.0078	0.9922	100.00
0.5	5,311,284	155,541	0.0293	0.9707	99.22
1.5	4,827,974	80,084	0.0166	0.9834	96.31
2.5	4,581,928	134,616	0.0294	0.9706	94.71
3.5	4,310,171	242,029	0.0562	0.9438	91.93
4.5	3,597,806	224,862	0.0625	0.9375	86.77
5.5	3,221,928	317,954	0.0987	0.9013	81.35
6.5	2,737,215	441,181	0.1612	0.8388	73.32
7.5	2,281,417	164,088	0.0719	0.9281	61.50
8.5	2,108,406	157,808	0.0748	0.9252	57.08
9.5	1,755,255	159,474	0.0909	0.9091	52.81
10.5	1,351,759	76,694	0.0567	0.9433	48.01
11.5	1,266,386	132,857	0.1049	0.8951	45.28
12.5	1,010,909		0.0000	1.0000	40.53
13.5	997,802	85,417	0.0856	0.9144	40.53
14.5	845,952	71,993	0.0851	0.9149	37.06
15.5	600,438	8,414	0.0140	0.9860	33.91
16.5	576,563	38,586	0.0669	0.9331	33.43
17.5	381,159	238,328	0.6253	0.3747	31.20
18.5	110,042	6,533	0.0594	0.9406	11.69
19.5	103,509	1,304	0.0126	0.9874	11.00
20.5	89,984	22,475	0.2498	0.7502	10.86
21.5	67,451	17,728	0.2628	0.7372	8.15
22.5	15,332	1,000	0.0652	0.9348	6.00
23.5	9,464		0.0000	1.0000	5.61
24.5	9,464		0.0000	1.0000	5.61
25.5	6,079		0.0000	1.0000	5.61
26.5	6,079		0.0000	1.0000	5.61
27.5	5,605		0.0000	1.0000	5.61
28.5	5,605		0.0000	1.0000	5.61
29.5	5,605		0.0000	1.0000	5.61
30.5	5,605		0.0000	1.0000	5.61
31.5	5,605		0.0000	1.0000	5.61
32.5	5,605	5,605	1.0000		5.61
33.5					


ORIGINAL CURVE
2008-2011 EXPERIENCE:
1981-2011 PLACEMENTS
IOWA 40-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80

PLACEMENT BAND 1981-2011 EXPERIENCE BAND 2008-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	66,147		0.0000	1.0000	100.00
0.5	116,981		0.0000	1.0000	100.00
1.5	160,220		0.0000	1.0000	100.00
2.5	179,807		0.0000	1.0000	100.00
3.5	122,918		0.0000	1.0000	100.00
4.5	75,685		0.0000	1.0000	100.00
5.5	25,100		0.0000	1.0000	100.00
6.5	3,969		0.0000	1.0000	100.00
7.5	12,663		0.0000	1.0000	100.00
8.5	55,508		0.0000	1.0000	100.00
9.5	55,508		0.0000	1.0000	100.00
10.5	72,899		0.0000	1.0000	100.00
11.5	76,945		0.0000	1.0000	100.00
12.5	32,002		0.0000	1.0000	100.00
13.5	163,356		0.0000	1.0000	100.00
14.5	155,596		0.0000	1.0000	100.00
15.5	142,856		0.0000	1.0000	100.00
16.5	140,986		0.0000	1.0000	100.00
17.5	9,631		0.0000	1.0000	100.00
18.5	2,150		0.0000	1.0000	100.00
19.5	30,029		0.0000	1.0000	100.00
20.5	30,029		0.0000	1.0000	100.00
21.5	42,951		0.0000	1.0000	100.00
22.5	40,801		0.0000	1.0000	100.00
23.5	12,922		0.0000	1.0000	100.00
24.5	16,250		0.0000	1.0000	100.00
25.5	3,328		0.0000	1.0000	100.00
26.5	8,776		0.0000	1.0000	100.00
27.5	8,776		0.0000	1.0000	100.00
28.5	5,448		0.0000	1.0000	100.00
29.5	5,448		0.0000	1.0000	100.00
30.5					100.00

PART VI. DETAILED DEPRECIATION CALCULATIONS

INTERIM SURVIVOR CURVE.. IOWA 72-R2
PROBABLE RETIREMENT YEAR.. 12-2052
NET SALVAGE PERCENT.. -10

1987	67,520.32	1.74	1,292.34	0.4263	31,662
1989	57,730.91	1.79	1,136.72	0.4028	25,579
1991	308.57	1.85	6.28	0.3792	129
1992	11,156.06	1.88	230.71	0.3666	4,499
2000	10,832.25	2.16	257.37	0.2484	2,960
2011	67,738.02	3.05	2,272.61	0.0152	1,133
	215,286.13		5,196.03		65,962

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.41

INTERIM SURVIVOR CURVE.. IOWA 103-R3
PROBABLE RETIREMENT YEAR.. 12-2052
NET SALVAGE PERCENT.. -10

1987	454,475.11	1.58	7,898.78	0.3871	193,520
1989	48,551.65	1.63	870.53	0.3668	19,590
1992	2,414.61	1.71	45.42	0.3334	886
1993	134,389.31	1.74	2,572.21	0.3219	47,586
1996	24,178.48	1.82	484.05	0.2821	7,503
1997	36,567.29	1.86	748.17	0.2697	10,848
2002	11,519.73	2.04	258.50	0.1938	2,456
2003	2,788.31	2.08	63.80	0.1768	542
2004	42,198.95	2.12	984.08	0.1590	7,381
2005	111,863.49	2.16	2,657.88	0.1404	17,276
2007	98,112.46	2.26	2,439.08	0.1017	10,976
2008	39,046.90	2.31	992.18	0.0808	3,470
2010	547,634.36	2.43	14,638.27	0.0364	21,927
2011	321,332.38	2.50	8,836.64	0.0125	4,418
	1,875,073.03		43,489.59		348,379

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.32

INTERIM SURVIVOR CURVE.. IOWA 85-R3
PROBABLE RETIREMENT YEAR.. 12-2052
NET SALVAGE PERCENT.. -10

1987	179,228.52	1.63	3,213.57	0.3994	78,742
2000	89,900.44	1.99	1,967.92	0.2288	22,626
2001	3,500.40	2.03	78.16	0.2132	821
2008	318,629.07	2.34	8,201.51	0.0819	28,705
2009	124,172.24	2.40	3,278.15	0.0600	8,195
2010	723,837.35	2.46	19,587.04	0.0369	29,381
2011	19,166.87	2.54	535.52	0.0127	268
	1,458,434.89		36,861.87		168,738

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.53

INTERIM SURVIVOR CURVE.. IOWA 45-R3
PROBABLE RETIREMENT YEAR.. 12-2052
NET SALVAGE PERCENT.. -10

1987	62,699.91	2.24	1,544.93	0.5488	37,851
1991	12,366.51	2.31	314.23	0.4736	6,442
2000	12,896.50	2.48	351.82	0.2852	4,046
2001	17,229.29	2.51	475.70	0.2636	4,996
	105,192.21		2,686.68		53,335

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.55

INTERIM SURVIVOR CURVE.. IOWA 30-R2
PROBABLE RETIREMENT YEAR.. 12-2052
NET SALVAGE PERCENT.. -10

1987	3,300.00	2.90	105.27	0.7105	2,579
1990	1,347.72	3.03	44.92	0.6514	966
1992	1,522.97	3.12	52.27	0.6084	1,019
1993	17,813.77	3.17	621.17	0.5864	11,491
2008	3,364.92	4.11	152.13	0.1438	532
2009	41,307.32	4.25	1,931.12	0.1062	4,826
	68,656.70		2,906.88		21,413

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.23

BEAVER CREEK
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	9,162.03	2.04	205.60	0.8262	8,327
1986	22,121.90	2.40	584.02	0.6120	14,892
1991	352.47	2.52	9.77	0.5166	200
2006	5,851.48	2.99	192.46	0.1644	1,058
	37,487.88		991.85		24,477

CARMACKS
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	5,170.46	2.04	116.03	0.8262	4,699
1993	32,889.08	2.57	929.77	0.4754	17,199
1997	12,049.89	2.67	353.91	0.3872	5,132
2005	11,904.48	2.94	384.99	0.1911	2,502
2006	105,725.03	2.99	3,477.30	0.1644	19,119
	167,738.94		5,262.00		48,651

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. -10

1971	22,662.51	2.09	521.01	0.8464	21,100
1985	13,952.01	2.73	418.98	0.7234	11,102
1991	352.46	3.20	12.41	0.6560	254
2006	5,314.95	5.87	343.19	0.3228	1,887
	42,281.93		1,295.59		34,343

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	59,126.21	2.04	1,326.79	0.8262	53,735
1976	1,003.99	2.16	23.85	0.7668	847

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1992	258.00	2.54	7.21	0.4953	141
1997	9,866.63	2.67	289.78	0.3872	4,202
2007	181,455.77	3.04	6,067.88	0.1368	27,305
2008	322,680.35	3.10	11,003.40	0.1085	38,512
2009	25,330.54	3.18	886.06	0.0795	2,215
2011	8,750.60	3.50	336.90	0.0175	168
	608,472.09		19,941.87		127,125

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	16,476.40	2.04	369.73	0.8262	14,974
1982	31,174.06	2.31	792.13	0.6814	23,366
1983	42,062.15	2.33	1,078.05	0.6640	30,722
1989	21,819.59	2.47	592.84	0.5558	13,340
1991	352.47	2.52	9.77	0.5166	200
1992	9,774.53	2.54	273.10	0.4953	5,325
1996	8,908.07	2.65	259.67	0.4108	4,025
1997	4,623.41	2.67	135.79	0.3872	1,969
1998	38,405.22	2.70	1,140.64	0.3645	15,399
2005	9,871.42	2.94	319.24	0.1911	2,075
2006	4,432.86	2.99	145.80	0.1644	802
	187,900.18		5,116.76		112,197

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. -10

1971	8,362.86	2.04	187.66	0.8262	7,600
1976	9,888.00	2.18	237.11	0.7739	8,418
1982	12,270.68	2.35	317.20	0.6932	9,357

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. -10

1988	17,015.74	2.57	481.03	0.6040	11,305
1991	352.47	2.70	10.47	0.5535	215
2004	1,001.91	3.72	41.00	0.2790	307
	48,891.66		1,274.47		37,202

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	10,571.03	2.04	237.21	0.8262	9,607
1974	8,707.10	2.11	202.09	0.7912	7,578
1976	4,684.35	2.16	111.30	0.7668	3,951
1978	170.40	2.21	4.14	0.7404	139
1989	8,000.00	2.47	217.36	0.5558	4,891
1992	109.38	2.54	3.06	0.4953	60
1993	22,783.19	2.57	644.08	0.4754	11,914
1997	16,193.47	2.67	475.60	0.3872	6,897
2006	100,002.48	2.99	3,289.08	0.1644	18,084
	171,221.40		5,183.92		63,121

STEWART CROSSING
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	6,882.44	2.04	154.44	0.8262	6,255
1982	11,893.33	2.31	302.21	0.6814	8,915
1988	14,778.07	2.45	398.27	0.5758	9,360
1993	3,486.70	2.57	98.57	0.4754	1,823
2005	210,924.97	2.94	6,821.31	0.1911	44,339
	247,965.51		7,774.80		70,692

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	4,531.30	2.04	101.68	0.8262	4,118
1998	15,739.26	2.70	467.46	0.3645	6,311
2005	2,232.71	2.94	72.21	0.1911	469
	22,503.27		641.35		10,898

TESLIN
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	10,350.29	2.04	232.26	0.8262	9,407
2005	8,079.46	2.94	261.29	0.1911	1,698
2011	19,556.13	3.50	752.91	0.0175	376
	37,985.88		1,246.46		11,481

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. -10

1987	311,360.32	2.43	8,322.66	0.5954	203,922
1988	7,591.41	2.45	204.59	0.5758	4,808
1997	10,471.46	2.66	306.39	0.3857	4,443
1999	29,783.20	2.71	887.84	0.3388	11,100
2001	186.47	2.76	5.66	0.2898	59
	359,392.86		9,727.14		224,332

MOBILES
SURVIVOR CURVE.. IOWA 40-R2.5
NET SALVAGE PERCENT.. -10

1971	10,662.39	2.04	239.26	0.8262	9,690
	10,662.39		239.26		9,690
	1,942,503.99		58,695.47		774,209

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.02

BEAVER CREEK
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1971	6,791.94	2.30	187.46	0.9315	7,592
1986	7,089.08	2.79	237.34	0.7114	6,052
1994	1,140.87	2.94	40.25	0.5145	704
1996	5,470.27	2.97	194.96	0.4604	3,022
1998	55,480.02	2.99	1,990.62	0.4036	26,870
2004	16,886.36	3.02	611.96	0.2265	4,590
	92,858.54		3,262.59		48,830

CARMACKS
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1973	196.46	2.38	5.61	0.9163	216
1990	40,197.77	2.88	1,389.23	0.6192	29,869
	40,394.23		1,394.84		30,085

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. -20

1973	3,283.83	2.38	93.79	0.9163	3,611
1997	63,293.96	3.87	2,939.37	0.5612	42,625
1999	16,409.95	4.16	819.18	0.5200	10,240
2003	1,332.07	4.93	78.81	0.4190	670
2004	3,051.15	5.17	189.29	0.3878	1,420
2005	14,133.96	5.44	922.66	0.3536	5,997
2008	1,140.87	6.48	88.71	0.2268	310
2009	2,832.53	6.92	235.21	0.1730	588
	105,478.32		5,367.02		65,461

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1982	100.00	2.68	3.22	0.7906	95
1994	397,144.70	2.94	14,011.27	0.5145	245,197
1998	68,555.35	2.99	2,459.77	0.4036	33,203
2004	4,343.08	3.02	157.39	0.2265	1,180
2008	148,989.27	3.04	5,435.13	0.1064	19,023
	619,132.40		22,066.78		298,698

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1971	1,829.28	2.30	50.49	0.9315	2,045
1973	18,132.52	2.38	517.86	0.9163	19,938
1985	8,400.29	2.76	278.22	0.7314	7,373
1994	52,075.44	2.94	1,837.22	0.5145	32,151
2003	86,979.73	3.02	3,152.15	0.2567	26,793
2004	1,140.87	3.02	41.35	0.2265	310
2005	46,528.71	3.02	1,686.20	0.1963	10,960
	215,086.84		7,563.49		99,570

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. -20

1971	87,626.71	2.30	2,418.50	0.9315	97,949
1994	7,779.75	3.00	280.07	0.5250	4,901
2003	7,023.17	3.49	294.13	0.2966	2,500
2005	13,194.21	3.68	582.66	0.2392	3,787
2008	13,678.17	4.05	664.76	0.1418	2,327
	129,302.01		4,240.12		111,464

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1986	293.14	2.79	9.81	0.7114	250
1994	1,005.32	2.94	35.47	0.5145	621
1996	9,000.00	2.97	320.76	0.4604	4,972
1998	60,463.08	2.99	2,169.42	0.4036	29,283
2003	14,364.08	3.02	520.55	0.2567	4,425
	85,125.62		3,056.01		39,551

STEWART CROSSING
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1971	2,790.21	2.30	77.01	0.9315	3,119
1993	8,091.37	2.93	284.49	0.5420	5,263
2004	27,639.59	3.02	1,001.66	0.2265	7,512
2008	14,000.48	3.04	510.74	0.1064	1,788
2011	12,585.49	3.06	462.14	0.0153	231
	65,107.14		2,336.04		17,913

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

1971	1,005.32	2.30	27.75	0.9315	1,124
1973	936.21	2.38	26.74	0.9163	1,029
1990	41,465.54	2.88	1,433.05	0.6192	30,811
1994	19,118.51	2.94	674.50	0.5145	11,804
1999	904.44	2.99	32.45	0.3738	406
	63,430.02		2,194.49		45,174

TESLIN
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -20

2004	99,862.71	3.02	3,619.02	0.2265	27,143
	99,862.71		3,619.02		27,143

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 35-R4
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. -20

1971	506.33	2.30	13.97	0.9315	566
1976	4,412.77	2.49	131.85	0.8840	4,681
1982	22,767.10	2.68	732.19	0.7906	21,600
1997	21,824.31	2.98	780.44	0.4321	11,316
1999	78,464.70	2.99	2,815.31	0.3738	35,196
2009	619,842.35	3.03	22,537.47	0.0758	56,381
	747,817.56		27,011.23		129,740

MOBILES
SURVIVOR CURVE.. IOWA 35-R4
NET SALVAGE PERCENT.. -20

1988	25,562.13	2.83	868.09	0.6650	20,399
	25,562.13		868.09		20,399
	2,289,157.52		82,979.72		934,028

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.62

BEAVER CREEK
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1983	6,729.90	3.02	223.57	0.8607	6,372
1988	35,130.86	3.37	1,302.30	0.7920	30,606
1989	38,776.08	3.44	1,467.29	0.7740	33,014
1991	197,994.87	3.58	7,797.04	0.7339	159,839
1992	2,889.71	3.65	116.02	0.7118	2,263
1993	147,926.58	3.72	6,053.16	0.6882	111,983
1994	51,495.19	3.78	2,141.17	0.6615	37,470
2000	13,621.40	4.09	612.83	0.4704	7,048
2003	29,551.12	4.18	1,358.76	0.3553	11,549
2004	11,663.55	4.20	538.86	0.3150	4,041
	535,779.26		21,611.00		404,185

CARMACKS
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1974	6,707.49	2.50	184.46	0.9375	6,917
1991	411,404.53	3.58	16,201.11	0.7339	332,123
1992	1,431.15	3.65	57.46	0.7118	1,121
	419,543.17		16,443.03		340,161

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. -10

1971	13,213.83	2.35	341.58	0.9518	13,835
1972	1,165.50	2.40	30.77	0.9480	1,215
1982	5,500.00	2.96	179.08	0.8732	5,283
1993	108,995.02	3.84	4,603.95	0.7104	85,173
2004	81,212.35	5.40	4,824.01	0.4050	36,180
2011	277,989.71	8.07	24,677.15	0.0404	12,354
	488,076.41		34,656.54		154,040

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1974	1,126.47	2.50	30.98	0.9375	1,162
1981	2,086.28	2.89	66.32	0.8814	2,023
1996	56,883.75	3.90	2,440.31	0.6045	37,825
	60,096.50		2,537.61		41,010

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1992	115,345.02	3.65	4,631.10	0.7118	90,313
1993	31,348.63	3.72	1,282.79	0.6882	23,732
1994	115,469.41	3.78	4,801.22	0.6615	84,021
1998	239,200.48	4.01	10,551.13	0.5414	142,453
2004	692,044.84	4.20	31,972.47	0.3150	239,794
2010	30,304.59	4.25	1,416.74	0.0638	2,127
	1,223,712.97		54,655.45		582,440

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. -10

1983	31,559.61	3.02	1,048.41	0.8607	29,880
1991	198,327.99	3.58	7,810.16	0.7339	160,108
1992	1,215.45	3.65	48.80	0.7118	952
1997	114,594.28	3.97	5,004.33	0.5756	72,557
1999	102,441.44	4.08	4,597.57	0.5100	57,470
2000	12.01	4.14	0.55	0.4761	6
2003	13,614.56	4.29	642.47	0.3646	5,460
2004	12,290.60	4.34	586.75	0.3255	4,401
	474,055.94		19,739.04		330,834

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	65.02	2.35	1.68	0.9518	68
1977	4,145.37	2.66	121.29	0.9177	4,185
1989	180,866.60	3.44	6,843.99	0.7740	153,990
1990	294.78	3.51	11.38	0.7546	245
1993	4,381.38	3.72	179.29	0.6882	3,317
	189,753.15		7,157.63		161,805

STEWART CROSSING
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1971	3,852.20	2.35	99.58	0.9518	4,033
1972	1,061.34	2.40	28.02	0.9480	1,107
1974	5,934.12	2.50	163.19	0.9375	6,120
1985	1,157.99	3.16	40.25	0.8374	1,067
1986	16.33	3.23	0.58	0.8236	15
1988	4,271.69	3.37	158.35	0.7920	3,721
2003	24,500.84	4.18	1,126.55	0.3553	9,576
2004	4,882.86	4.20	225.59	0.3150	1,692
	45,677.37		1,842.11		27,331

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1970	9,236.40	2.31	234.70	0.9586	9,739
1991	5,179.53	3.58	203.97	0.7339	4,181
1992	25,847.73	3.65	1,037.79	0.7118	20,238
1998	59,650.02	4.01	2,631.16	0.5414	35,524
2003	79,944.14	4.18	3,675.83	0.3553	31,245
2004	2,700.87	4.20	124.78	0.3150	936
2009	58,488.49	4.25	2,734.34	0.1062	6,833
	241,047.18		10,642.57		108,696

TESLIN
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. -10

1993	762,033.60	3.72	31,182.41	0.6882	576,875
	762,033.60		31,182.41		576,875

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. -10

1973	11,370.97	2.45	306.45	0.9432	11,798
1978	2,815.04	2.71	83.92	0.9078	2,811
1981	7,682.30	2.89	244.22	0.8814	7,448
1985	589,119.42	3.16	20,477.79	0.8374	542,661
1986	1,654.02	3.23	58.77	0.8236	1,498
1987	70,000.00	3.30	2,541.00	0.8085	62,254
1989	8,785.44	3.44	332.44	0.7740	7,480
1991	377,412.18	3.58	14,862.49	0.7339	304,681
1993	48,060.52	3.72	1,966.64	0.6882	36,383
1996	250,658.18	3.90	10,753.24	0.6045	166,675
1999	516,871.37	4.05	23,026.62	0.5062	287,804
2000	19,585.15	4.09	881.14	0.4704	10,134
2002	6,723.20	4.16	307.65	0.3952	2,923
2011	258,457.58	4.25	12,082.89	0.0212	6,027
	2,169,195.37		87,925.26		1,450,577

MOBILES
SURVIVOR CURVE.. IOWA 26-S2.5
NET SALVAGE PERCENT.. -10

1982	2,314.53	2.96	75.36	0.8732	2,223
1984	6,948.44	3.09	236.18	0.8498	6,495
1986	52,884.26	3.23	1,878.98	0.8236	47,911
1987	155.25	3.30	5.64	0.8085	138
1988	11,501.98	3.37	426.38	0.7920	10,021
1989	17,870.50	3.44	676.22	0.7740	15,215
1990	155,054.72	3.51	5,986.66	0.7546	128,705
1991	52,410.38	3.58	2,063.92	0.7339	42,310

MOBILES
SURVIVOR CURVE.. IOWA 26-S2.5
NET SALVAGE PERCENT.. -10

1998	106,050.80	4.01	4,677.90	0.5414	63,157
1999	12,279.04	4.05	547.03	0.5062	6,837
2010	151,030.51	4.25	7,060.68	0.0638	10,599
	568,500.41		23,634.95		333,611
	7,177,471.33		312,027.60		4,511,565

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.35

BEAVER CREEK
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	3,820.66	2.22	84.82	0.8991	3,435
1972	342.83	2.25	7.71	0.8888	305
1974	126.08	2.32	2.93	0.8700	110
1977	161.28	2.42	3.90	0.8349	135
1980	1,172.29	2.52	29.54	0.7938	931
1983	3,521.61	2.62	92.27	0.7467	2,630
1992	27,277.24	2.87	782.86	0.5596	15,264
1994	144.34	2.92	4.21	0.5110	74
1998	11,389.22	3.02	343.95	0.4077	4,643
1999	27,540.86	3.04	837.24	0.3800	10,466
2000	7,962.35	3.06	243.65	0.3519	2,802
2003	29,551.12	3.13	924.95	0.2660	7,861
2004	11,663.54	3.15	367.40	0.2362	2,755
2006	9,236.84	3.20	295.58	0.1760	1,626
2007	15,499.19	3.23	500.62	0.1454	2,254
2008	20,159.43	3.25	655.18	0.1138	2,294
2009	3,796.60	3.29	124.91	0.0822	312
	173,365.48		5,301.72		57,897

CARMACKS
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	1,753.43	2.22	38.93	0.8991	1,577
1999	4,228.29	3.04	128.54	0.3800	1,607
2000	22,636.55	3.06	692.68	0.3519	7,966
2001	72,540.11	3.09	2,241.49	0.3244	23,532
	101,158.38		3,101.64		34,682

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. 0

1971	3,489.80	2.22	77.47	0.8991	3,138
1972	392.81	2.26	8.88	0.8927	351

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. 0

1976	2,134.00	2.41	51.43	0.8556	1,826
1980	2,677.41	2.57	68.81	0.8096	2,168
1985	1,408.73	2.83	39.87	0.7500	1,057
1990	70,054.07	3.17	2,220.71	0.6816	47,749
1991	4,985.00	3.26	162.51	0.6683	3,331
1993	33,561.73	3.45	1,157.88	0.6382	21,419
1994	1,818.80	3.55	64.57	0.6212	1,130
1998	7,421.15	4.07	302.04	0.5494	4,077
1999	14,916.17	4.22	629.46	0.5275	7,868
2000	15,290.59	4.39	671.26	0.5048	7,719
2001	16,054.87	4.58	735.31	0.4809	7,721
2003	28,717.40	5.01	1,438.74	0.4258	12,228
2004	4,956.93	5.26	260.73	0.3945	1,956
2006	9,043.55	5.84	528.14	0.3212	2,905
2007	4,788.51	6.19	296.41	0.2786	1,334
2008	62,915.66	6.58	4,139.85	0.2303	14,489
	284,627.18		12,854.07		142,466

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	14,437.93	2.22	320.52	0.8991	12,981
1972	16,367.43	2.25	368.27	0.8888	14,547
2001	43,957.09	3.09	1,358.27	0.3244	14,260
2002	18,022.71	3.11	560.51	0.2954	5,324
2006	2,166.70	3.20	69.33	0.1760	381
	94,951.86		2,676.90		47,493

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1981	3,895.02	2.55	99.32	0.7778	3,030
1982	17,114.85	2.59	443.27	0.7640	13,076

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1986	23,198.32	2.70	626.35	0.6885	15,972
1989	22,032.00	2.79	614.69	0.6278	13,832
1990	6,856.39	2.82	193.35	0.6063	4,157
1998	34,163.99	3.02	1,031.75	0.4077	13,929
1999	2,398.51	3.04	72.91	0.3800	911
2000	9,706.06	3.06	297.01	0.3519	3,416
	119,365.14		3,378.65		68,323

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. 0

1989	35,003.00	2.82	987.08	0.6345	22,209
1990	6,856.39	2.86	196.09	0.6149	4,216
1991	4,985.00	2.89	144.07	0.5924	2,953
1993	11,042.37	2.98	329.06	0.5513	6,088
1994	1,392.96	3.03	42.21	0.5302	739
1997	206,593.21	3.19	6,590.32	0.4626	95,570
1998	3,965.69	3.25	128.88	0.4388	1,740
1999	5,250.25	3.32	174.31	0.4150	2,179
2000	110.64	3.39	3.75	0.3898	43
2003	13,614.56	3.65	496.93	0.3102	4,223
2004	12,290.60	3.75	460.90	0.2812	3,456
2006	8,425.63	3.98	335.34	0.2189	1,844
2007	18,831.92	4.11	773.99	0.1850	3,484
2008	103,372.31	4.25	4,393.32	0.1488	15,382
	431,734.53		15,056.25		164,126

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	1,502.01	2.22	33.34	0.8991	1,350
1973	2,302.74	2.29	52.73	0.8816	2,030
1989	375.00	2.79	10.46	0.6278	235

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1990	6,856.39	2.82	193.35	0.6063	4,157
1998	4,769.62	3.02	144.04	0.4077	1,945
1999	20,795.02	3.04	632.17	0.3800	7,902
2000	87,363.46	3.06	2,673.32	0.3519	30,743
2004	907.50	3.15	28.59	0.2362	214
	124,871.74		3,768.00		48,576

STEWART CROSSING
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	1,063.94	2.22	23.62	0.8991	957
1982	7,537.07	2.59	195.21	0.7640	5,758
1998	11,389.20	3.02	343.95	0.4077	4,643
1999	6,183.82	3.04	187.99	0.3800	2,350
2000	14,867.21	3.06	454.94	0.3519	5,232
2003	24,500.84	3.13	766.88	0.2660	6,517
2004	4,882.85	3.15	153.81	0.2362	1,153
	70,424.93		2,126.40		26,610

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1986	100.02	2.70	2.70	0.6885	69
1991	4,985.00	2.84	141.57	0.5822	2,902
1998	43,772.61	3.02	1,321.93	0.4077	17,846
1999	869.59	3.04	26.44	0.3800	330
2000	110.61	3.06	3.38	0.3519	39
2003	33,457.39	3.13	1,047.22	0.2660	8,900

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

2004	1,582.78	3.15	49.86	0.2362	374
2009	4,969.67	3.29	163.50	0.0822	409
2010	3,712.47	3.33	123.63	0.0500	186
	93,560.14		2,880.23		31,055

TESLIN
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1976	544.02	2.39	13.00	0.8484	462
1981	487.94	2.55	12.44	0.7778	380
1982	2,068.56	2.59	53.58	0.7640	1,580
1993	26,881.19	2.90	779.55	0.5365	14,422
1999	4,228.29	3.04	128.54	0.3800	1,607
2001	20,206.63	3.09	624.38	0.3244	6,555
	54,416.63		1,611.49		25,006

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. 0

1971	40,922.41	2.22	908.48	0.8991	36,793
1973	12,675.52	2.29	290.27	0.8816	11,175
1974	5,654.23	2.32	131.18	0.8700	4,919
1976	782.05	2.39	18.69	0.8484	663
1984	9,095.34	2.65	241.03	0.7288	6,629
1987	220,208.40	2.73	6,011.69	0.6688	147,275
1989	42,648.64	2.79	1,189.90	0.6278	26,775
1990	31,215.94	2.82	880.29	0.6063	18,926
1994	6,000.88	2.92	175.23	0.5110	3,066
1997	13,284.17	2.99	397.20	0.4336	5,760
1998	3,968.07	3.02	119.84	0.4077	1,618
1999	77,281.64	3.04	2,349.36	0.3800	29,367
2000	1,866.83	3.06	57.12	0.3519	657
2002	12,712.92	3.11	395.37	0.2954	3,755

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 35-R3
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. 0

2004	2,043.14	3.15	64.36	0.2362	483
2005	4,960.69	3.17	157.25	0.2060	1,022
2007	30,679.14	3.21	984.80	0.1444	4,430
2008	9,332.25	3.23	301.43	0.1130	1,055
2011	52,856.96	3.36	1,775.99	0.0168	888
	578,189.22		16,449.48		305,256

MOBILES
SURVIVOR CURVE.. IOWA 35-R3
NET SALVAGE PERCENT.. 0

1971	10,783.16	2.22	239.39	0.8991	9,695
1986	5,350.99	2.70	144.48	0.6885	3,684
1993	17,452.58	2.90	506.12	0.5365	9,363
2000	18,845.94	3.06	576.69	0.3519	6,632
2001	35,219.37	3.09	1,088.28	0.3244	11,425
	87,652.04		2,554.96		40,799
	2,214,317.27		71,759.79		992,289

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.24

BEAVER CREEK
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	184.59	2.09	3.86	0.8464	156
1982	694.02	2.36	16.38	0.6962	483
1991	2,135.57	2.55	54.46	0.5228	1,116
2003	8,443.18	2.78	234.72	0.2363	1,995
2004	3,332.42	2.80	93.31	0.2100	700
2007	22,115.51	2.89	639.14	0.1300	2,875
2009	11,697.35	2.96	346.24	0.0740	866
	48,602.64		1,388.11		8,191

CARMACKS
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	26.10	2.09	0.55	0.8464	22
1982	430.77	2.36	10.17	0.6962	300
2010	3,578.86	3.01	107.72	0.0452	162
2011	3,330.38	3.09	102.91	0.0154	51
	7,366.11		221.35		535

DESTRUCTION BAY
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2023
NET SALVAGE PERCENT.. 0

1979	1,551.73	2.42	37.55	0.7865	1,220
1982	1,587.73	2.56	40.65	0.7552	1,199
1991	7,781.34	3.19	248.22	0.6540	5,089
1993	198.09	3.38	6.70	0.6253	124
2003	8,204.98	4.97	407.79	0.4224	3,466
2004	1,416.28	5.22	73.93	0.3915	554
2007	2,392.19	6.15	147.12	0.2768	662
2009	4,915.64	7.00	344.09	0.1750	860
	28,047.98		1,306.05		13,174

HAINES JUNCTION
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	1,283.32	2.09	26.82	0.8464	1,086
1982	430.77	2.36	10.17	0.6962	300
2007	740.06	2.89	21.39	0.1300	96
	2,454.15		58.38		1,482

OLD CROW
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	334.88	2.09	7.00	0.8464	283
1982	430.77	2.36	10.17	0.6962	300
1991	845.54	2.55	21.56	0.5228	442
1992	89,611.14	2.57	2,303.01	0.5012	44,913
1996	76.70	2.64	2.02	0.4092	31
1998	25,966.14	2.68	695.89	0.3618	9,395
2004	51,464.79	2.80	1,441.01	0.2100	10,808
2007	2,765.55	2.89	79.92	0.1300	360
	171,495.51		4,560.58		66,532

PELLY CROSSING
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2033
NET SALVAGE PERCENT.. 0

1971	63.84	2.09	1.33	0.8464	54
1982	2,232.98	2.38	53.14	0.7021	1,568
1991	23,272.01	2.70	628.34	0.5535	12,881
1992	1,386.99	2.74	38.00	0.5343	741
2003	3,889.87	3.53	137.31	0.3000	1,167
2004	3,511.59	3.63	127.47	0.2722	956
2007	7,139.56	4.01	286.30	0.1804	1,288
2009	11,771.71	4.32	508.54	0.1080	1,271
2011	8,216.80	4.74	389.48	0.0237	195
	61,485.35		2,169.91		20,121

ROSS RIVER
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	388.01	2.09	8.11	0.8464	328
1982	430.77	2.36	10.17	0.6962	300
2007	8,820.43	2.89	254.91	0.1300	1,147
	9,639.21		273.19		1,775

STEWART CROSSING
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1971	136.08	2.09	2.84	0.8464	115
1982	2,482.06	2.36	58.58	0.6962	1,728
1992	1,243.54	2.57	31.96	0.5012	623
2003	7,000.23	2.78	194.61	0.2363	1,654
2004	1,395.10	2.80	39.06	0.2100	293
2009	24,862.34	2.96	735.93	0.0740	1,840
2011	47,562.55	3.09	1,469.68	0.0154	732
	84,681.90		2,532.66		6,985

SWIFT RIVER
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1982	430.31	2.36	10.16	0.6962	300
1998	1,482.16	2.68	39.72	0.3618	536
2003	9,559.27	2.78	265.75	0.2363	2,259
2004	452.22	2.80	12.66	0.2100	95
	11,923.96		328.29		3,190

TESLIN
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2053
NET SALVAGE PERCENT.. 0

1982	430.77	2.36	10.17	0.6962	300
2007	69,113.54	2.89	1,997.38	0.1300	8,985
2009	233.79	2.96	6.92	0.0740	17
	69,778.10		2,014.47		9,302

WATSON LAKE
INTERIM SURVIVOR CURVE.. IOWA 40-R3
PROBABLE RETIREMENT YEAR.. 12-2113
NET SALVAGE PERCENT.. 0

1971	963.89	2.09	20.15	0.8464	816
1979	2,627.48	2.29	60.17	0.7442	1,955
1982	12,722.46	2.36	300.25	0.6962	8,857
1987	14,434.04	2.47	356.52	0.6052	8,735
1997	54,613.60	2.66	1,452.72	0.3857	21,064
1999	8,046.80	2.69	216.46	0.3362	2,705
2000	1,450.00	2.71	39.30	0.3116	452
2007	112,714.67	2.82	3,178.55	0.1269	14,303
2008	26,941.49	2.84	765.14	0.0994	2,678
2011	23,915.13	2.95	705.50	0.0148	354
	258,429.56		7,094.76		61,919

MOBILES
SURVIVOR CURVE.. IOWA 40-R3
NET SALVAGE PERCENT.. 0

2005	18,356.25	2.79	512.14	0.1814	3,330
2006	27,067.90	2.80	757.90	0.1540	4,168
2007	32,689.60	2.82	921.85	0.1269	4,148
2010	5,364.03	2.89	155.02	0.0434	233
2011	8,691.73	2.95	256.41	0.0148	129
	92,169.51		2,603.32		12,008
	846,073.98		24,551.07		205,214

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.90

SURVIVOR CURVE.. IOWA 50-R4
NET SALVAGE PERCENT.. -10

1957	8,481.84	1.67	155.81	0.9102	8,492
1960	3,229.85	1.73	61.46	0.8910	3,166
1961	657.80	1.75	12.66	0.8838	640
1963	1,015.95	1.78	19.89	0.8633	965
1964	213.85	1.80	4.23	0.8550	201
1965	410.15	1.82	8.21	0.8463	382
1966	62.60	1.83	1.26	0.8326	57
1967	5,878.36	1.85	119.62	0.8232	5,323
1968	14,018.01	1.86	286.81	0.8091	12,476
1969	25,261.00	1.87	519.62	0.7948	22,085
1970	17,772.00	1.89	369.48	0.7844	15,334
1971	3,930.00	1.90	82.14	0.7695	3,327
1974	41,250.75	1.94	880.29	0.7275	33,011
1975	143,608.80	1.95	3,080.41	0.7118	112,443
1981	8,150.00	2.01	180.20	0.6130	5,496
1982	3,210.00	2.02	71.33	0.5959	2,104
1984	9,590.00	2.04	215.20	0.5610	5,918
1985	14,603.26	2.05	329.30	0.5432	8,726
1986	43,015.79	2.06	974.74	0.5253	24,856
1988	21,596.39	2.07	491.75	0.4864	11,555
1989	18,476.14	2.07	420.70	0.4658	9,467
1992	231,307.73	2.09	5,317.76	0.4076	103,709
1993	460,428.37	2.09	10,585.25	0.3866	195,802
1996	147,978.24	2.10	3,418.30	0.3255	52,984
1997	94,152.91	2.11	2,185.29	0.3060	31,692
1999	62,040.09	2.11	1,439.95	0.2638	18,003
2000	4,081.39	2.11	94.73	0.2426	1,089
	1,384,421.27		31,326.39		689,303

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.26

SURVIVOR CURVE.. IOWA 75-R3
NET SALVAGE PERCENT.. 0

1971	1,500.00	1.35	20.25	0.5468	820
1979	198.05	1.39	2.75	0.4518	89
1994	12,700.80	1.46	185.43	0.2555	3,245
1995	44,975.18	1.47	661.14	0.2426	10,911
1996	46,085.52	1.47	677.46	0.2278	10,498
1997	140,113.75	1.48	2,073.68	0.2146	30,068
1998	50,522.14	1.48	747.73	0.1998	10,094
1999	50,004.19	1.49	745.06	0.1862	9,311
2000	49,670.66	1.49	740.09	0.1714	8,514
2001	55,348.17	1.49	824.69	0.1564	8,656
2002	34,647.85	1.50	519.72	0.1425	4,937
2003	61,972.64	1.50	929.59	0.1275	7,902
2004	60,926.26	1.51	919.99	0.1132	6,897
2005	204,085.51	1.51	3,081.69	0.0982	20,041
2006	46,254.29	1.52	703.07	0.0836	3,867
2007	69,728.37	1.53	1,066.84	0.0688	4,797
2008	103,657.56	1.53	1,585.96	0.0536	5,556
2009	72,924.99	1.54	1,123.04	0.0385	2,808
2010	86,743.57	1.56	1,353.20	0.0234	2,030
2011	75,548.93	1.58	1,193.67	0.0079	597
	1,267,608.43		19,155.05		151,638

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.51

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -75

1958	3,014.82	1.70	89.69	0.9095	4,798
1959	3,422.64	1.72	103.02	0.9030	5,409
1960	64,066.35	1.74	1,950.82	0.8961	100,467
1961	22,262.77	1.76	685.69	0.8888	34,628
1962	17,904.69	1.78	557.73	0.8811	27,608
1963	22,736.58	1.80	716.20	0.8730	34,736
1964	25,528.25	1.82	813.07	0.8645	38,621
1965	24,225.28	1.84	780.05	0.8556	36,273
1966	70,219.67	1.86	2,285.65	0.8463	103,997
1967	36,246.48	1.88	1,192.51	0.8366	53,067
1968	96,667.60	1.90	3,214.20	0.8265	139,818
1969	106,747.78	1.92	3,586.73	0.8160	152,436
1970	16,023.49	1.94	544.00	0.8051	22,576
1971	18,709.16	1.96	641.72	0.7938	25,990
1972	129,825.22	1.98	4,498.44	0.7821	177,689
1973	98,707.41	2.00	3,454.76	0.7700	133,008
1974	89,544.20	2.02	3,165.39	0.7575	118,702
1975	146,445.21	2.04	5,228.09	0.7446	190,825
1976	96,229.81	2.06	3,469.08	0.7313	123,153
1977	240,706.63	2.07	8,719.60	0.7142	300,847
1978	212,027.14	2.09	7,754.89	0.7002	259,807
1979	200,296.24	2.11	7,395.94	0.6858	240,386
1980	108,769.20	2.13	4,054.37	0.6710	127,722
1981	129,163.87	2.14	4,837.19	0.6527	147,534
1982	354,099.48	2.16	13,384.96	0.6372	394,856
1983	135,039.76	2.18	5,151.77	0.6213	146,825
1984	273,619.23	2.19	10,486.46	0.6022	288,354
1985	754,437.87	2.21	29,177.88	0.5856	773,148
1986	279,561.30	2.22	10,860.96	0.5661	276,954
1987	417,946.08	2.24	16,383.49	0.5488	401,395
1988	333,623.95	2.26	13,194.83	0.5311	310,078
1989	575,010.94	2.27	22,842.31	0.5108	514,002
1990	1,110,346.89	2.29	44,497.15	0.4924	956,786
1991	782,222.41	2.30	31,484.45	0.4715	645,431
1992	1,164,266.14	2.32	47,269.21	0.4524	921,750
1993	1,574,269.86	2.33	64,190.85	0.4310	1,187,393
1994	1,005,504.27	2.35	41,351.36	0.4112	723,561
1995	900,750.05	2.36	37,200.98	0.3894	613,816
1996	899,513.01	2.37	37,307.30	0.3674	578,342
1997	770,189.70	2.39	32,213.18	0.3466	467,159
1998	679,543.24	2.40	28,540.82	0.3240	385,301
1999	766,596.42	2.41	32,331.20	0.3012	404,073

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -75

2000	612,683.04	2.43	26,054.35	0.2794	299,571
2001	636,466.49	2.44	27,177.12	0.2562	285,360
2002	985,772.90	2.45	42,265.01	0.2328	401,604
2003	775,635.83	2.46	33,391.12	0.2091	283,825
2004	1,281,162.37	2.48	55,602.45	0.1860	417,018
2005	989,206.22	2.49	43,104.66	0.1618	280,094
2006	1,401,831.25	2.50	61,330.12	0.1375	337,316
2007	1,091,993.21	2.52	48,156.90	0.1134	216,706
2008	1,616,156.35	2.53	71,555.32	0.0886	250,585
2009	1,327,095.60	2.55	59,221.64	0.0638	148,170
2010	1,874,751.64	2.57	84,316.96	0.0386	126,639
2011	2,882,760.32	2.62	132,174.56	0.0131	66,087
	30,231,546.31		1,271,958.20		15,702,296

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.21

SURVIVOR CURVE.. IOWA 45-R4
NET SALVAGE PERCENT.. -80

1948	148.71	1.55	4.15	0.9842	263
1949	510.02	1.57	14.41	0.9812	901
1950	123.73	1.59	3.54	0.9778	218
1951	739.89	1.61	21.44	0.9740	1,297
1952	1,127.00	1.63	33.07	0.9698	1,967
1953	2,029.00	1.65	60.26	0.9652	3,525
1954	2,638.00	1.67	79.30	0.9602	4,559
1955	418.31	1.69	12.72	0.9548	719
1956	2,743.00	1.71	84.43	0.9490	4,686
1957	922.06	1.73	28.71	0.9428	1,565
1958	5,559.00	1.76	176.11	0.9416	9,422
1959	8,040.00	1.78	257.60	0.9345	13,524
1960	72,384.01	1.80	2,345.24	0.9270	120,780
1961	9,293.00	1.83	306.11	0.9242	15,459
1962	12,100.41	1.85	402.94	0.9158	19,947
1963	14,243.14	1.87	479.42	0.9070	23,253
1964	10,540.74	1.90	360.49	0.9025	17,123
1965	14,565.83	1.92	503.40	0.8928	23,408
1966	43,767.33	1.94	1,528.36	0.8827	69,540
1967	35,893.76	1.96	1,266.33	0.8722	56,352
1968	68,248.09	1.98	2,432.36	0.8613	105,808
1969	125,172.05	2.00	4,506.19	0.8500	191,513
1970	27,008.59	2.02	982.03	0.8383	40,754
1971	18,964.86	2.04	696.39	0.8262	28,204
1972	109,788.05	2.06	4,070.94	0.8137	160,802
1973	108,551.49	2.08	4,064.17	0.8008	156,470
1974	57,051.46	2.09	2,146.28	0.7838	80,490
1975	144,638.16	2.11	5,493.36	0.7702	200,521
1976	106,854.96	2.13	4,096.82	0.7562	145,447
1977	145,040.78	2.14	5,586.97	0.7383	192,750
1978	93,920.92	2.16	3,651.65	0.7236	122,330
1979	77,160.47	2.17	3,013.89	0.7052	97,944
1980	122,191.66	2.19	4,816.80	0.6898	151,718
1981	87,840.47	2.20	3,478.48	0.6710	106,094
1982	209,885.33	2.21	8,349.24	0.6520	246,321
1983	132,046.38	2.23	5,300.34	0.6356	151,072
1984	121,892.29	2.24	4,914.70	0.6160	135,154
1985	677,899.61	2.25	27,454.93	0.5962	727,495
1986	136,683.35	2.26	5,560.28	0.5763	141,787
1987	328,625.90	2.27	13,427.65	0.5562	329,007
1988	239,184.34	2.28	9,816.13	0.5358	230,679
1989	332,701.42	2.29	13,713.95	0.5152	308,534

SURVIVOR CURVE.. IOWA 45-R4
NET SALVAGE PERCENT.. -80

1990	680,637.85	2.30	28,178.41	0.4945	605,836
1991	519,771.93	2.30	21,518.56	0.4715	441,130
1992	486,666.63	2.31	20,235.60	0.4504	394,550
1993	792,959.72	2.32	33,114.00	0.4292	612,609
1994	463,654.51	2.32	19,362.21	0.4060	338,839
1995	357,845.36	2.33	15,008.03	0.3844	247,600
1996	560,475.87	2.33	23,506.36	0.3612	364,399
1997	521,699.29	2.34	21,973.97	0.3393	318,623
1998	410,383.42	2.34	17,285.35	0.3159	233,352
1999	410,977.25	2.34	17,310.36	0.2925	216,380
2000	479,332.56	2.35	20,275.77	0.2702	233,128
2001	472,747.67	2.35	19,997.23	0.2468	210,013
2002	511,085.75	2.35	21,618.93	0.2232	205,334
2003	423,598.69	2.35	17,918.22	0.1998	152,343
2004	778,010.48	2.35	32,909.84	0.1762	246,754
2005	793,470.21	2.36	33,706.61	0.1534	219,093
2006	1,160,619.99	2.36	49,303.14	0.1298	271,167
2007	1,581,317.34	2.36	67,174.36	0.1062	302,285
2008	1,517,742.62	2.36	64,473.71	0.0826	225,658
2009	942,790.65	2.36	40,049.75	0.0590	100,124
2010	1,356,461.25	2.36	57,622.47	0.0354	86,434
2011	1,583,225.80	2.37	67,540.41	0.0118	33,628
	20,514,612.41		855,624.87		10,498,681

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.17

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -10

1945	2,203.16	1.45	35.14	0.9642	2,337
1946	414.58	1.47	6.70	0.9628	439
1947	476.35	1.49	7.81	0.9610	504
1948	569.49	1.50	9.40	0.9525	597
1949	673.48	1.52	11.26	0.9500	704
1950	808.02	1.54	13.69	0.9471	842
1951	900.65	1.56	15.46	0.9438	935
1952	1,366.00	1.58	23.74	0.9401	1,413
1953	2,459.00	1.60	43.28	0.9360	2,532
1954	3,197.00	1.61	56.62	0.9258	3,256
1955	2,771.00	1.63	49.68	0.9210	2,807
1956	3,325.00	1.65	60.35	0.9158	3,350
1957	3,592.00	1.67	65.99	0.9102	3,596
1958	1,170.00	1.70	21.88	0.9095	1,171
1959	1,533.00	1.72	29.00	0.9030	1,523
1960	1,560.00	1.74	29.86	0.8961	1,538
1961	1,791.78	1.76	34.69	0.8888	1,752
1962	5,328.00	1.78	104.32	0.8811	5,164
1963	2,524.00	1.80	49.98	0.8730	2,424
1964	4,560.00	1.82	91.29	0.8645	4,336
1965	3,229.00	1.84	65.35	0.8556	3,039
1966	4,597.36	1.86	94.06	0.8463	4,280
1967	7,481.00	1.88	154.71	0.8366	6,884
1968	8,000.00	1.90	167.20	0.8265	7,273
1969	7,521.50	1.92	158.85	0.8160	6,751
1970	11,754.13	1.94	250.83	0.8051	10,410
1971	12,073.93	1.96	260.31	0.7938	10,543
1972	12,957.01	1.98	282.20	0.7821	11,147
1973	14,692.86	2.00	323.24	0.7700	12,445
1974	20,167.00	2.02	448.11	0.7575	16,804
1975	34,619.23	2.04	776.86	0.7446	28,355
1976	37,678.27	2.06	853.79	0.7313	30,310
1977	42,422.26	2.07	965.95	0.7142	33,328
1978	62,182.03	2.09	1,429.56	0.7002	47,894
1979	52,049.79	2.11	1,208.08	0.6858	39,265
1980	43,273.51	2.13	1,013.90	0.6710	31,940
1981	53,231.36	2.14	1,253.07	0.6527	38,219
1982	30,980.05	2.16	736.09	0.6372	21,715
1983	40,503.38	2.18	971.27	0.6213	27,681
1984	40,236.69	2.19	969.30	0.6022	26,654
1985	32,685.06	2.21	794.57	0.5856	21,054
1986	51,608.88	2.22	1,260.29	0.5661	32,137

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -10

1987	67,879.82	2.24	1,672.56	0.5488	40,978
1988	66,613.00	2.26	1,656.00	0.5311	38,916
1989	81,267.48	2.27	2,029.25	0.5108	45,663
1990	89,672.48	2.29	2,258.85	0.4924	48,570
1991	108,151.36	2.30	2,736.23	0.4715	56,093
1992	163,702.21	2.32	4,177.68	0.4524	81,465
1993	112,072.14	2.33	2,872.41	0.4310	53,133
1994	64,781.32	2.35	1,674.60	0.4112	29,302
1995	55,117.61	2.36	1,430.85	0.3894	23,609
1997	45,912.56	2.39	1,207.04	0.3466	17,505
1998	46,874.69	2.40	1,237.49	0.3240	16,706
1999	40,693.10	2.41	1,078.77	0.3012	13,482
2000	33,672.14	2.43	900.06	0.2794	10,349
2001	25,583.05	2.44	686.65	0.2562	7,210
2002	59,316.63	2.45	1,598.58	0.2328	15,190
2003	55,673.16	2.46	1,506.52	0.2091	12,805
2004	68,225.83	2.48	1,861.20	0.1860	13,959
2005	63,429.49	2.49	1,737.33	0.1618	11,289
2006	136,065.53	2.50	3,741.80	0.1375	20,580
2007	191,840.99	2.52	5,317.83	0.1134	23,930
2008	225,262.76	2.53	6,269.06	0.0886	21,954
2009	129,908.59	2.55	3,643.94	0.0638	9,117
2010	31,334.64	2.57	885.83	0.0386	1,330
2011	221,235.12	2.62	6,376.00	0.0131	3,188
	2,849,452.51		73,754.26		1,125,671

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.59

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -50

1961	12.02	1.76	0.32	0.8888	16
1969	1,356.35	1.92	39.06	0.8160	1,660
1971	65.00	1.96	1.91	0.7938	77
1972	14,154.38	1.98	420.39	0.7821	16,605
1973	5,056.00	2.00	151.68	0.7700	5,840
1974	7,373.22	2.02	223.41	0.7575	8,378
1975	8,587.37	2.04	262.77	0.7446	9,591
1976	66,670.57	2.06	2,060.12	0.7313	73,134
1977	4,549.00	2.07	141.25	0.7142	4,873
1978	257,255.88	2.09	8,064.97	0.7002	270,196
1979	17,007.99	2.11	538.30	0.6858	17,496
1980	716,055.98	2.13	22,877.99	0.6710	720,710
1981	23,266.00	2.14	746.84	0.6527	22,779
1982	49,311.39	2.16	1,597.69	0.6372	47,132
1983	68,295.31	2.18	2,233.26	0.6213	63,648
1984	32,676.52	2.19	1,073.42	0.6022	29,517
1985	61,229.70	2.21	2,029.76	0.5856	53,784
1986	21,965.42	2.22	731.45	0.5661	18,652
1987	181,124.12	2.24	6,085.77	0.5488	149,101
1988	70,261.38	2.26	2,381.86	0.5311	55,974
1989	1,382,612.06	2.27	47,077.94	0.5108	1,059,357
1990	239,241.64	2.29	8,217.95	0.4924	176,704
1991	171,937.17	2.30	5,931.83	0.4715	121,603
1992	736,477.56	2.32	25,629.42	0.4524	499,774
1993	996,540.23	2.33	34,829.08	0.4310	644,263
1994	267,822.74	2.35	9,440.75	0.4112	165,193
1995	1,124,713.96	2.36	39,814.87	0.3894	656,945
1996	533,259.01	2.37	18,957.36	0.3674	293,879
1997	1,120,397.24	2.39	40,166.24	0.3466	582,495
1998	658,133.08	2.40	23,692.79	0.3240	319,853
1999	875,078.79	2.41	31,634.10	0.3012	395,361
2000	527,543.67	2.43	19,228.97	0.2794	221,094
2001	1,723,813.98	2.44	63,091.59	0.2562	662,462
2002	1,013,816.38	2.45	37,257.75	0.2328	354,025
2003	1,153,334.82	2.46	42,558.05	0.2091	361,743
2004	997,611.57	2.48	37,111.15	0.1860	278,334
2005	724,497.68	2.49	27,059.99	0.1618	175,836
2006	740,562.48	2.50	27,771.09	0.1375	152,741
2007	826,505.65	2.52	31,241.91	0.1134	140,589
2008	823,804.14	2.53	31,263.37	0.0886	109,484

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -50

2009	1,222,366.98	2.55	46,755.54	0.0638	116,981
2010	627,766.58	2.57	24,200.40	0.0386	36,348
2011	888,477.52	2.62	34,917.17	0.0131	17,459
	20,982,588.53		759,511.53		9,111,686

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.62

SURVIVOR CURVE.. IOWA 40-R4
NET SALVAGE PERCENT.. -10

1978	8,805.65	2.35	227.63	0.7872	7,625
1979	16,155.81	2.37	421.18	0.7702	13,688
1980	5,116.57	2.39	134.51	0.7528	4,237
1981	14,328.30	2.41	379.84	0.7350	11,584
1982	6,135.87	2.43	164.01	0.7168	4,838
1983	4,112.25	2.45	110.83	0.6982	3,158
1984	6,049.74	2.47	164.37	0.6792	4,520
1985	2,467.31	2.49	67.58	0.6598	1,791
1986	47,595.84	2.50	1,308.89	0.6375	33,377
1987	64,385.16	2.52	1,784.76	0.6174	43,727
1988	55,348.04	2.53	1,540.34	0.5946	36,201
1989	64,252.19	2.54	1,795.21	0.5715	40,392
1990	63,917.48	2.56	1,799.92	0.5504	38,698
1991	85,692.58	2.57	2,422.53	0.5268	49,657
1992	151,300.89	2.58	4,293.92	0.5031	83,731
1993	198,187.47	2.59	5,646.36	0.4792	104,469
1994	84,909.93	2.60	2,428.42	0.4550	42,497
1995	123,873.01	2.61	3,556.39	0.4306	58,674
1996	226,325.88	2.61	6,497.82	0.4046	100,729
1997	125,671.06	2.62	3,621.84	0.3799	52,517
1998	99,659.29	2.62	2,872.18	0.3537	38,774
1999	72,633.75	2.63	2,101.29	0.3288	26,270
2000	15,457.57	2.63	447.19	0.3024	5,142
2001	64,800.69	2.64	1,881.81	0.2772	19,759
2002	71,681.66	2.64	2,081.64	0.2508	19,776
2003	75,033.52	2.64	2,178.97	0.2244	18,521
2004	206,861.36	2.65	6,030.01	0.1988	45,236
2005	148,375.29	2.65	4,325.14	0.1722	28,105
2006	233,234.91	2.65	6,798.80	0.1458	37,406
2007	163,236.52	2.65	4,758.34	0.1192	21,404
2008	95,096.67	2.65	2,772.07	0.0928	9,707
2009	39,357.36	2.66	1,151.60	0.0665	2,879
2010	94,836.76	2.66	2,774.92	0.0399	4,162
2011	218,180.81	2.66	6,383.97	0.0133	3,192
	2,953,077.19		84,924.28		1,016,443

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.88

SURVIVOR CURVE.. IOWA 15-L0
NET SALVAGE PERCENT.. 0

1970	18.15	2.25	0.41	0.9338	17
1971	4,291.77	2.30	98.71	0.9315	3,998
1972	4,159.27	2.34	97.33	0.9243	3,844
1973	4,922.20	2.39	117.64	0.9202	4,529
1974	1,065.68	2.44	26.00	0.9150	975
1975	10,392.34	2.49	258.77	0.9088	9,445
1976	3,532.46	2.55	90.08	0.9052	3,198
1977	2,160.36	2.61	56.39	0.9004	1,945
1978	3,961.72	2.66	105.38	0.8911	3,530
1979	468.92	2.73	12.80	0.8872	416
1980	4,344.54	2.79	121.21	0.8788	3,818
1981	3,588.21	2.86	102.62	0.8723	3,130
1982	5,232.71	2.93	153.32	0.8644	4,523
1983	562.52	3.00	16.88	0.8550	481
1984	2,268.84	3.08	69.88	0.8470	1,922
1985	4,581.74	3.16	144.78	0.8374	3,837
1986	4,570.19	3.25	148.53	0.8288	3,788
1987	8,609.54	3.34	287.56	0.8183	7,045
1988	11,962.73	3.44	411.52	0.8084	9,671
1989	35,899.48	3.54	1,270.84	0.7965	28,594
1990	12,441.33	3.65	454.11	0.7848	9,764
1991	11,062.14	3.76	415.94	0.7708	8,527
1992	35,072.97	3.88	1,360.83	0.7566	26,536
1993	62,568.13	4.01	2,508.98	0.7418	46,413
1994	6,205.20	4.15	257.52	0.7262	4,506
1995	9,796.96	4.30	421.27	0.7095	6,951
1996	8,617.32	4.46	384.33	0.6913	5,957
1997	20,081.35	4.64	931.77	0.6728	13,511
1998	95,664.33	4.82	4,611.02	0.6507	62,249
1999	71,622.77	5.03	3,602.63	0.6288	45,036
2000	110,805.59	5.26	5,828.37	0.6049	67,026
2001	38,275.23	5.51	2,108.97	0.5786	22,146
2002	38,701.01	5.79	2,240.79	0.5500	21,286
2003	109,974.70	6.10	6,708.46	0.5185	57,022
2004	120,520.80	6.46	7,785.64	0.4845	58,392
2005	15,995.63	6.87	1,098.90	0.4466	7,144
2006	8,685.31	7.36	639.24	0.4048	3,516
2007	39,317.09	7.94	3,121.78	0.3573	14,048
2008	18,765.20	8.66	1,625.07	0.3031	5,688

SURVIVOR CURVE.. IOWA 15-L0
NET SALVAGE PERCENT.. 0

2009	15,676.06	9.58	1,501.77	0.2395	3,754
2010	482,401.74	10.87	52,437.07	0.1630	78,631
2011	235,141.02	13.19	31,015.10	0.0660	15,519
	1,683,985.25		134,650.21		682,328

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 8.00

SURVIVOR CURVE.. IOWA 15-R2.5
NET SALVAGE PERCENT.. 0

2007	7,789.88	7.26	565.55	0.3267	2,545
2008	29,425.21	7.45	2,192.18	0.2608	7,674
2009	11,869.27	7.67	910.37	0.1918	2,277
2010	12,710.93	7.94	1,009.25	0.1191	1,514
2011	5,851.04	8.50	497.34	0.0425	249
	67,646.33		5,174.69		14,259

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 7.65

SURVIVOR CURVE.. IOWA 40-R4
NET SALVAGE PERCENT.. -10

1960	3,631.70	1.87	74.70	0.9630	3,847
1968	16,606.00	2.10	383.60	0.9135	16,687
1969	882.00	2.13	20.67	0.9052	878
1971	39,959.05	2.18	958.22	0.8829	38,808
1972	2,089.52	2.21	50.80	0.8730	2,007
1973	56,550.00	2.24	1,393.39	0.8624	53,646
1974	446.22	2.26	11.09	0.8475	416
1976	333,091.33	2.31	8,463.85	0.8200	300,448
1977	70,884.17	2.33	1,816.76	0.8038	62,674
1979	14,954.00	2.37	389.85	0.7702	12,669
1980	80,834.73	2.39	2,125.15	0.7528	66,938
1981	126,329.84	2.41	3,349.00	0.7350	102,138
1985	43,522.68	2.49	1,192.09	0.6598	31,588
1986	118,315.85	2.50	3,253.69	0.6375	82,969
1987	335,797.16	2.52	9,308.30	0.6174	228,053
1988	60,907.24	2.53	1,695.05	0.5946	39,837
1989	36,582.03	2.54	1,022.10	0.5715	22,997
1990	132,200.60	2.56	3,722.77	0.5504	80,040
1991	259,920.34	2.57	7,347.95	0.5268	150,619
1992	98,578.56	2.58	2,797.66	0.5031	54,554
1993	166,934.17	2.59	4,755.95	0.4792	87,994
1994	41,680.13	2.60	1,192.05	0.4550	20,861
1996	196,092.49	2.61	5,629.82	0.4046	87,273
1997	1,451.70	2.62	41.84	0.3799	607
1999	46,617.77	2.63	1,348.65	0.3288	16,861
2000	79,093.83	2.63	2,288.18	0.3024	26,310
2001	253,074.36	2.64	7,349.28	0.2772	77,167
2005	491,706.97	2.65	14,333.26	0.1722	93,139
2006	22,338.61	2.65	651.17	0.1458	3,583
	3,131,073.05		86,966.89		1,765,608

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.78

SURVIVOR CURVE.. IOWA 30-R3
NET SALVAGE PERCENT.. -10

1974	4,057.78	2.46	109.80	0.9225	4,118
1975	230.46	2.51	6.36	0.9162	232
1977	42,389.29	2.60	1,212.33	0.8970	41,826
1978	22,260.89	2.64	646.46	0.8844	21,656
1979	15,471.24	2.69	457.79	0.8742	14,877
1980	184,650.87	2.74	5,565.38	0.8631	175,309
1981	28,488.46	2.79	874.31	0.8510	26,668
1982	69,549.87	2.83	2,165.09	0.8348	63,866
1983	113,988.36	2.88	3,611.15	0.8208	102,918
1984	98,481.92	2.92	3,163.24	0.8030	86,989
1985	29,194.06	2.96	950.56	0.7844	25,190
1986	348,615.98	3.01	11,542.68	0.7676	294,357
1987	137,151.99	3.05	4,601.45	0.7472	112,728
1988	209,962.68	3.09	7,136.63	0.7262	167,722
1989	572,762.96	3.13	19,720.23	0.7042	443,674
1990	271,383.70	3.17	9,463.15	0.6816	203,473
1991	222,337.62	3.21	7,850.74	0.6580	160,928
1992	89,796.68	3.25	3,210.23	0.6338	62,604
1993	353,801.93	3.28	12,765.17	0.6068	236,156
1994	247,288.34	3.32	9,030.97	0.5810	158,042
1995	310,528.34	3.36	11,477.13	0.5544	189,373
1996	107,223.57	3.39	3,998.37	0.5254	61,969
1997	413,878.23	3.42	15,570.10	0.4959	225,766
1998	217,759.97	3.46	8,287.94	0.4671	111,887
1999	251,341.73	3.49	9,649.01	0.4362	120,599
2000	210,200.54	3.52	8,138.96	0.4048	93,598
2001	356,557.44	3.55	13,923.57	0.3728	146,217
2002	195,535.23	3.58	7,700.18	0.3401	73,152
2003	588,194.07	3.61	23,357.19	0.3068	198,504
2004	504,727.00	3.64	20,209.27	0.2730	151,570
2005	109,056.61	3.67	4,402.62	0.2386	28,623
2006	799,992.38	3.70	32,559.69	0.2035	179,078
2007	524,616.74	3.73	21,525.02	0.1678	96,834
2008	217,945.03	3.76	9,014.21	0.1316	31,550
2009	584,538.96	3.79	24,369.43	0.0948	60,956
2010	196,401.93	3.83	8,274.41	0.0574	12,401
2011	497,158.76	3.91	21,382.80	0.0196	10,719
	9,147,521.61		347,923.62		4,196,129

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.80

SURVIVOR CURVE.. IOWA 23-R2
NET SALVAGE PERCENT.. 0

1967	2,516.28			1.0000	2,516
1973	1,471.00	2.53	37.22	0.9740	1,433
1974	19,675.00	2.58	507.62	0.9675	19,036
1975	4,754.00	2.62	124.55	0.9563	4,546
1976	14,852.76	2.68	398.05	0.9514	14,131
1977	10,540.00	2.73	287.74	0.9418	9,927
1978	16,073.00	2.78	446.83	0.9313	14,969
1979	29,321.00	2.84	832.72	0.9230	27,063
1980	18,970.00	2.90	550.13	0.9135	17,329
1981	17,037.00	2.96	504.30	0.9028	15,381
1982	9,135.00	3.03	276.79	0.8938	8,165
1983	10,835.00	3.09	334.80	0.8806	9,541
1984	19,067.94	3.16	602.55	0.8690	16,570
1985	10,529.38	3.23	340.10	0.8560	9,013
1986	31,912.79	3.30	1,053.12	0.8415	26,855
1987	14,211.05	3.37	478.91	0.8256	11,733
1988	13,496.10	3.44	464.27	0.8084	10,910
1989	7,391.51	3.51	259.44	0.7898	5,838
1990	3,329.07	3.58	119.18	0.7697	2,562
1991	2,562.75	3.66	93.80	0.7503	1,923
1992	10,584.67	3.73	394.81	0.7274	7,699
1993	152.13	3.80	5.78	0.7030	107
1997	15,872.16	4.11	652.35	0.5960	9,460
1999	448.69	4.27	19.16	0.5338	240
	284,738.28		8,784.22		246,947

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.09

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -10

1946	226.33	1.47	3.66	0.9628	240
1947	1,242.88	1.49	20.37	0.9610	1,314
1948	1,616.79	1.50	26.68	0.9525	1,694
1950	28.96	1.54	0.49	0.9471	30
1951	15,498.02	1.56	265.95	0.9438	16,090
1952	20,900.00	1.58	363.24	0.9401	21,613
1953	2,758.00	1.60	48.54	0.9360	2,840
1954	5,453.44	1.61	96.58	0.9258	5,554
1955	21,326.43	1.63	382.38	0.9210	21,606
1956	3,729.00	1.65	67.68	0.9158	3,757
1958	2,255.00	1.70	42.17	0.9095	2,256
1959	18,726.00	1.72	354.30	0.9030	18,601
1960	37,058.01	1.74	709.29	0.8961	36,528
1961	10,822.00	1.76	209.51	0.8888	10,580
1962	9,436.00	1.78	184.76	0.8811	9,145
1963	24,530.00	1.80	485.69	0.8730	23,556
1964	6,995.00	1.82	140.04	0.8645	6,652
1965	13,727.00	1.84	277.83	0.8556	12,919
1966	36,590.20	1.86	748.64	0.8463	34,063
1967	62,470.06	1.88	1,291.88	0.8366	57,489
1968	178,530.55	1.90	3,731.29	0.8265	162,311
1969	37,843.96	1.92	799.26	0.8160	33,969
1970	47,642.66	1.94	1,016.69	0.8051	42,193
1971	67,977.76	1.96	1,465.60	0.7938	59,357
1972	78,104.06	1.98	1,701.11	0.7821	67,194
1973	67,293.83	2.00	1,480.46	0.7700	56,998
1974	69,239.74	2.02	1,538.51	0.7575	57,694
1975	105,252.50	2.04	2,361.87	0.7446	86,208
1976	70,666.88	2.06	1,601.31	0.7313	56,847
1977	93,514.46	2.07	2,129.32	0.7142	73,467
1978	141,818.02	2.09	3,260.40	0.7002	109,231
1979	191,093.76	2.11	4,435.29	0.6858	144,157
1980	191,440.72	2.13	4,485.46	0.6710	141,302
1981	185,345.66	2.14	4,363.04	0.6527	133,073
1982	125,172.27	2.16	2,974.09	0.6372	87,736
1983	65,923.13	2.18	1,580.84	0.6213	45,054
1984	57,612.00	2.19	1,387.87	0.6022	38,163
1985	202,526.99	2.21	4,923.43	0.5856	130,460
1986	205,124.37	2.22	5,009.14	0.5661	127,733
1987	505,597.46	2.24	12,457.92	0.5488	305,219
1988	306,132.88	2.26	7,610.46	0.5311	178,846
1989	485,270.58	2.27	12,117.21	0.5108	272,664

SURVIVOR CURVE.. IOWA 45-R3
NET SALVAGE PERCENT.. -10

1990	725,712.71	2.29	18,280.70	0.4924	393,075
1991	767,112.63	2.30	19,407.95	0.4715	397,863
1992	770,960.71	2.32	19,674.92	0.4524	383,661
1993	941,284.95	2.33	24,125.13	0.4310	446,263
1994	504,127.56	2.35	13,031.70	0.4112	228,027
1995	470,411.85	2.36	12,211.89	0.3894	201,496
1996	655,953.00	2.37	17,100.69	0.3674	265,097
1997	483,875.09	2.39	12,721.08	0.3466	184,482
1998	494,985.10	2.40	13,067.61	0.3240	176,413
1999	375,346.25	2.41	9,950.43	0.3012	124,360
2000	591,914.63	2.43	15,821.88	0.2794	181,919
2001	574,603.49	2.44	15,422.36	0.2562	161,935
2002	539,849.29	2.45	14,548.94	0.2328	138,245
2003	740,255.14	2.46	20,031.30	0.2091	170,266
2004	737,246.07	2.48	20,112.07	0.1860	150,841
2005	1,390,573.02	2.49	38,087.80	0.1618	247,494
2006	1,480,794.08	2.50	40,721.84	0.1375	223,970
2007	1,586,755.13	2.52	43,984.85	0.1134	197,932
2008	1,953,714.12	2.53	54,371.86	0.0886	190,409
2009	1,715,673.49	2.55	48,124.64	0.0638	120,406
2010	1,410,673.11	2.57	39,879.73	0.0386	59,897
2011	1,741,434.38	2.62	50,188.14	0.0131	25,094
	24,427,769.16		649,017.76		7,365,548

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.66

SURVIVOR CURVE.. IOWA 40-L3
NET SALVAGE PERCENT.. 0

1972	59,482.48	2.00	1,189.65	0.7900	46,991
1973	16,635.00	2.04	339.35	0.7854	13,065
1974	46,735.00	2.08	972.09	0.7800	36,453
1976	1,500.00	2.16	32.40	0.7668	1,150
1977	1,015.00	2.19	22.23	0.7556	767
1979	14,807.00	2.27	336.12	0.7378	10,925
1981	12,462.00	2.35	292.86	0.7168	8,933
1982	21,706.00	2.39	518.77	0.7050	15,303
1984	24,285.00	2.46	597.41	0.6765	16,429
1986	2,778.08	2.53	70.29	0.6452	1,792
1987	379,195.74	2.55	9,669.49	0.6248	236,921
1988	87,857.59	2.58	2,266.73	0.6063	53,268
1989	3,500.00	2.61	91.35	0.5872	2,055
1990	45,253.00	2.63	1,190.15	0.5654	25,586
1991	1,424,433.43	2.65	37,747.49	0.5432	773,752
1992	300,985.15	2.67	8,036.30	0.5206	156,693
1993	117,588.04	2.69	3,163.12	0.4976	58,512
1994	58,849.20	2.71	1,594.81	0.4742	27,906
1995	33,602.05	2.72	913.98	0.4488	15,081
1996	25,776.27	2.74	706.27	0.4247	10,947
1997	55,730.18	2.75	1,532.58	0.3988	22,225
1998	83,574.87	2.77	2,315.02	0.3740	31,257
1999	9,019.44	2.78	250.74	0.3475	3,134
2000	50,931.86	2.79	1,421.00	0.3208	16,339
2001	47,503.75	2.80	1,330.10	0.2940	13,966
2002	25,441.90	2.81	714.92	0.2670	6,793
2003	46,885.37	2.82	1,322.17	0.2397	11,238
2004	48,669.62	2.82	1,372.48	0.2115	10,294
2005	3,289.66	2.82	92.77	0.1833	603
2006	83,642.46	2.83	2,367.08	0.1556	13,015
2007	12,536.74	2.83	354.79	0.1274	1,597
2008	76,031.98	2.83	2,151.71	0.0990	7,527
2009	74,558.63	2.83	2,110.01	0.0708	5,279
2010	98,128.40	2.83	2,777.03	0.0424	4,161
2011	64,924.42	2.83	1,837.36	0.0142	922
	3,459,315.31		91,700.62		1,660,879

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.65

SURVIVOR CURVE.. 15-SQUARE
NET SALVAGE PERCENT.. 0

1988	834.92			1.0000	835
1989	2,150.48			1.0000	2,150
1990	1,503.14			1.0000	1,503
1991	2,966.04			1.0000	2,966
1992	909.82			1.0000	910
1993	378.67			1.0000	379
1996	7,412.16			1.0000	7,412
1997	2,902.53	6.67	193.60	0.9667	2,806
1998	13,797.39	6.67	920.29	0.9000	12,418
1999	9,644.27	6.67	643.27	0.8333	8,037
2000	2,749.22	6.67	183.37	0.7667	2,108
2001	5,644.80	6.67	376.51	0.7000	3,951
2004	2,243.36	6.67	149.63	0.5000	1,122
2005	10,922.40	6.67	728.52	0.4333	4,733
2006	5,995.34	6.67	399.89	0.3667	2,198
2007	10,018.97	6.67	668.27	0.3000	3,006
2008	10,493.44	6.67	699.91	0.2333	2,448
2009	858.00	6.67	57.23	0.1667	143
2010	10,095.47	6.67	673.37	0.1000	1,010
2011	71,272.97	6.67	4,753.91	0.0333	2,376
	172,793.39		10,447.77		62,511

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.05

SURVIVOR CURVE.. 5-SQUARE
NET SALVAGE PERCENT.. 0

2004	74.62			1.0000	75
2006	2,646.27			1.0000	2,646
2007	299.99	20.00	60.00	0.9000	270
2008	2,677.00	20.00	535.40	0.7000	1,874
2009	1,308.00	20.00	261.60	0.5000	654
2010	4,466.89	20.00	893.38	0.3000	1,340
2011	35,893.75	20.00	7,178.75	0.1000	3,589
	47,366.52		8,929.13		10,448

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 18.85

SURVIVOR CURVE.. IOWA 12-L0
NET SALVAGE PERCENT.. +25

1984	474.75	3.27	11.64	0.8992	320
1986	3,385.00	3.46	87.84	0.8823	2,240
1988	4,868.01	3.67	133.99	0.8624	3,149
1989	34,390.39	3.79	977.55	0.8528	21,996
1990	58.50	3.92	1.72	0.8428	37
1991	12,221.00	4.05	371.21	0.8302	7,609
1993	32,789.25	4.34	1,067.29	0.8029	19,745
1994	156,818.41	4.51	5,304.38	0.7892	92,821
1995	15,460.68	4.68	542.67	0.7722	8,954
1996	173,521.43	4.88	6,350.88	0.7564	98,439
1997	66,433.55	5.08	2,531.12	0.7366	36,701
1998	13,106.81	5.31	521.98	0.7168	7,046
1999	122,619.76	5.55	5,104.05	0.6938	63,805
2000	8,679.83	5.83	379.53	0.6704	4,364
2001	244,021.20	6.13	11,218.87	0.6436	117,789
2002	195,342.59	6.46	9,464.35	0.6137	89,911
2003	8,923.42	6.85	458.44	0.5822	3,896
2004	14,617.59	7.28	798.12	0.5460	5,986
2005	166,758.22	7.79	9,742.85	0.5064	63,335
2006	151,016.59	8.39	9,502.72	0.4614	52,259
2007	470,336.39	9.13	32,206.28	0.4108	144,911
2008	137,140.79	10.04	10,326.70	0.3514	36,143
2009	165,961.58	11.23	13,978.11	0.2808	34,952
2010	308,325.84	12.93	29,899.90	0.1940	44,861
2011	53,875.44	16.05	6,485.26	0.0802	3,241
	2,561,147.02		157,467.45		964,510

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.15

SURVIVOR CURVE.. 15-SQUARE
NET SALVAGE PERCENT.. 0

1991	3,238.21			1.0000	3,238
1992	156.97			1.0000	157
1993	1,288.17			1.0000	1,288
1994	3,064.70			1.0000	3,065
1995	1,070.05			1.0000	1,070
1996	10,038.84			1.0000	10,039
1997	8,816.70	6.67	588.07	0.9667	8,523
1998	18,273.33	6.67	1,218.83	0.9000	16,446
1999	63,438.59	6.67	4,231.35	0.8333	52,865
2000	6,165.19	6.67	411.22	0.7667	4,727
2001	8,154.41	6.67	543.90	0.7000	5,708
2002	87,515.51	6.67	5,837.28	0.6333	55,426
2003	23,582.40	6.67	1,572.95	0.5667	13,363
2004	36,733.49	6.67	2,450.12	0.5000	18,367
2005	17,543.91	6.67	1,170.18	0.4333	7,602
2006	55,899.76	6.67	3,728.51	0.3667	20,497
2007	48,284.13	6.67	3,220.55	0.3000	14,485
2008	45,514.89	6.67	3,035.84	0.2333	10,620
2009	37,388.92	6.67	2,493.84	0.1667	6,232
2010	176,091.78	6.67	11,745.32	0.1000	17,609
2011	66,923.57	6.67	4,463.80	0.0333	2,231
	719,183.52		46,711.76		273,558

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.50

SURVIVOR CURVE.. 15-SQUARE
NET SALVAGE PERCENT.. 0

1981	12,328.84			1.0000	12,329
1982	997.00			1.0000	997
1983	2,693.00			1.0000	2,693
1985	7,145.00			1.0000	7,145
1986	5,470.00			1.0000	5,470
1987	654.46			1.0000	654
1988	3,067.50			1.0000	3,068
1989	6,505.50			1.0000	6,506
1990	12,083.42			1.0000	12,083
1991	5,466.50			1.0000	5,466
1992	8,287.00			1.0000	8,287
1993	4,525.80			1.0000	4,526
1994	37,148.37			1.0000	37,148
1995	8,886.16			1.0000	8,886
1996	12,061.22			1.0000	12,061
1997	32,424.05	6.67	2,162.68	0.9667	31,343
1998	4,662.16	6.67	310.97	0.9000	4,196
1999	179,948.08	6.67	12,002.54	0.8333	149,956
2000	19,678.50	6.67	1,312.56	0.7667	15,087
2001	11,510.86	6.67	767.77	0.7000	8,058
2002	5,582.26	6.67	372.34	0.6333	3,535
2003	649.95	6.67	43.35	0.5667	368
2004	1,628.00	6.67	108.59	0.5000	814
2005	9,903.90	6.67	660.59	0.4333	4,292
2006	41,356.93	6.67	2,758.51	0.3667	15,164
2007	54,141.89	6.67	3,611.26	0.3000	16,243
2008	59,380.00	6.67	3,960.65	0.2333	13,855
2009	47,209.25	6.67	3,148.86	0.1667	7,868
2010	228,077.07	6.67	15,212.74	0.1000	22,808
2011	49,368.98	6.67	3,292.91	0.0333	1,645
	872,841.65		49,726.32		422,551

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.70

SURVIVOR CURVE.. IOWA 40-R3
NET SALVAGE PERCENT.. -10

1981	5,448.00	2.34	140.23	0.7137	4,277
1983	3,328.00	2.38	87.13	0.6783	2,483
1986	12,922.45	2.44	346.84	0.6222	8,844
1988	27,878.53	2.49	763.59	0.5852	17,946
1989	2,150.47	2.51	59.37	0.5648	1,336
1993	9,630.81	2.58	273.32	0.4773	5,056
1994	131,354.79	2.60	3,756.75	0.4550	65,743
1995	1,870.05	2.62	53.89	0.4323	889
1996	12,740.02	2.64	369.97	0.4092	5,735
1997	17,391.56	2.66	508.88	0.3857	7,379
1999	46,813.85	2.69	1,385.22	0.3362	17,313
2000	8,693.67	2.71	259.16	0.3116	2,980
2003	3,969.00	2.76	120.50	0.2346	1,024
2005	21,131.34	2.79	648.52	0.1814	4,217
2006	50,584.94	2.80	1,558.02	0.1540	8,569
2007	51,201.54	2.82	1,588.27	0.1269	7,147
2008	56,889.23	2.84	1,777.22	0.0994	6,220
2009	1,543.92	2.86	48.57	0.0715	121
2010	7,346.76	2.89	233.55	0.0434	351
2011	367.33	2.95	11.92	0.0148	6
	473,256.26		13,990.92		167,636

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.96

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1986	6		0		0		0
1987							
1988							
1989							
1990							
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003	10,000		0		0		0
2004	2,028		0		0		0
2005							
2006							
2007							
2008							
2009							
2010		5,300				5,300-	
2011	170		0		0		0
TOTAL	12,204	5,300	43		0	5,300-	43-
THREE-YEAR MOVING AVERAGES							
86-88	2		0		0		0
87-89							
88-90							
89-91							
90-92							
91-93							
92-94							
93-95							
94-96							
95-97							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03	3,333		0		0		0
02-04	4,009		0		0		0
03-05	4,009		0		0		0
04-06	676		0		0		0
05-07							
06-08							
07-09							
08-10		1,767				1,767-	
09-11	57	1,767			0	1,767-	
FIVE-YEAR AVERAGE							
07-11	34	1,060			0	1,060-	

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	2		0		0		0
1984							
1985							
1986							
1987	3,626		0		0		0
1988	1,203		0		0		0
1989							
1990							
1991							
1992	302		0		0		0
1993							
1994							
1995							
1996							
1997	120		0		0		0
1998	10,000	18,319	183		0	18,319-	183-
1999							
2000							
2001							
2002							
2003	10,000		0		0		0
2004	9,322		0		0		0
2005							
2006							
2007	3,200		0		0		0
2008							
2009							
2010							
2011	23,752		0		0		0
TOTAL	61,527	18,319	30		0	18,319-	30-

THREE-YEAR MOVING AVERAGES

83-85	1		0		0		0
84-86							
85-87	1,209		0		0		0
86-88	1,610		0		0		0
87-89	1,610		0		0		0
88-90	401		0		0		0
89-91							
90-92	101		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	101		0		0		0
92-94	101		0		0		0
93-95							
94-96							
95-97	40		0		0		0
96-98	3,373	6,106	181		0	6,106-	181-
97-99	3,373	6,106	181		0	6,106-	181-
98-00	3,333	6,106	183		0	6,106-	183-
99-01							
00-02							
01-03	3,333		0		0		0
02-04	6,441		0		0		0
03-05	6,441		0		0		0
04-06	3,107		0		0		0
05-07	1,067		0		0		0
06-08	1,067		0		0		0
07-09	1,067		0		0		0
08-10							
09-11	7,917		0		0		0
FIVE-YEAR AVERAGE							
07-11	5,390		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	10,551		0	129	1	129	1
1984	25,040		0		0		0
1985	116,422		0	73,537	63	73,537	63
1986	38,264		0		0		0
1987	8,299		0	2,000	24	2,000	24
1988	16,483		0	1,500	9	1,500	9
1989	111,612		0		0		0
1990	22,062		0		0		0
1991	171,400		0	18,663	11	18,663	11
1992	2,560		0	1,010	39	1,010	39
1993	2,200		0	2,200	100	2,200	100
1994							
1995							
1996							
1997	93,041	28,503	31	10,449	11	18,054-	19-
1998	52,500	33,360	64	1,000	2	32,360-	62-
1999	325,787	15,390	5		0	15,390-	5-
2000							
2001							
2002							
2003							
2004	47,038		0		0		0
2005							
2006							
2007							
2008							
2009							
2010							
2011	2,043,336	1,800	0		0	1,800-	0
TOTAL	3,086,595	79,053	3	110,488	4	31,435	1
THREE-YEAR MOVING AVERAGES							
83-85	50,671		0	24,555	48	24,555	48
84-86	59,909		0	24,512	41	24,512	41
85-87	54,328		0	25,179	46	25,179	46
86-88	21,015		0	1,167	6	1,167	6
87-89	45,465		0	1,167	3	1,167	3
88-90	50,052		0	500	1	500	1
89-91	101,691		0	6,221	6	6,221	6
90-92	65,341		0	6,558	10	6,558	10

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	58,720		0	7,291	12	7,291	12
92-94	1,587		0	1,070	67	1,070	67
93-95	733		0	733	100	733	100
94-96							
95-97	31,014	9,501	31	3,483	11	6,018-	19-
96-98	48,514	20,621	43	3,816	8	16,805-	35-
97-99	157,109	25,751	16	3,816	2	21,935-	14-
98-00	126,096	16,250	13	333	0	15,917-	13-
99-01	108,596	5,130	5		0	5,130-	5-
00-02							
01-03							
02-04	15,679		0		0		0
03-05	15,679		0		0		0
04-06	15,679		0		0		0
05-07							
06-08							
07-09							
08-10							
09-11	681,112	600	0		0	600-	0
FIVE-YEAR AVERAGE							
07-11	408,667	360	0		0	360-	0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	72		0		0		0
1986							
1987							
1988							
1989	12,995		0		0		0
1990	2,846		0		0		0
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001	15,000		0		0		0
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011	188,181		0		0		0
TOTAL	219,094		0		0		0
THREE-YEAR MOVING AVERAGES							
85-87	24		0		0		0
86-88							
87-89	4,332		0		0		0
88-90	5,280		0		0		0
89-91	5,280		0		0		0
90-92	949		0		0		0
91-93							
92-94							
93-95							
94-96							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
95-97							
96-98							
97-99							
98-00							
99-01	5,000		0		0		0
00-02	5,000		0		0		0
01-03	5,000		0		0		0
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11	62,727		0		0		0
FIVE-YEAR AVERAGE							
07-11	37,636		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	64		0		0		0
1986							
1987							
1988							
1989							
1990							
1991							
1992	1,327		0		0		0
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011	14,213		0		0		0
TOTAL	15,604		0		0		0
THREE-YEAR MOVING AVERAGES							
85-87	21		0		0		0
86-88							
87-89							
88-90							
89-91							
90-92	442		0		0		0
91-93	442		0		0		0
92-94	442		0		0		0
93-95							
94-96							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11	4,738		0		0		0
FIVE-YEAR AVERAGE							
07-11	2,843		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 457.00 - SUBSTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	2,888		0		0		0
1984	197		0		0		0
1985							
1986							
1987							
1988	33		0		0		0
1989							
1990							
1991							
1992							
1993							
1994	4,796		0		0		0
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008	7,356		0		0		0
2009	10,164		0		0		0
2010							
2011							
TOTAL	25,434		0		0		0
THREE-YEAR MOVING AVERAGES							
83-85	1,028		0		0		0
84-86	66		0		0		0
85-87							
86-88	11		0		0		0
87-89	11		0		0		0
88-90	11		0		0		0
89-91							
90-92							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 457.00 - SUBSTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93							
92-94	1,599	0		0		0	
93-95	1,599	0		0		0	
94-96	1,599	0		0		0	
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08	2,452	0		0		0	
07-09	5,840	0		0		0	
08-10	5,840	0		0		0	
09-11	3,388	0		0		0	
FIVE-YEAR AVERAGE							
07-11	3,504	0		0		0	

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YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 471.00 - LAND RIGHTS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 473.00 - POLES, TOWERS AND FIXTURES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	20,711	5,124	25		0	5,124-	25-
1984	7,236	420	6		0	420-	6-
1985	1,877	1,316	70		0	1,316-	70-
1986	22,910	3,807	17		0	3,807-	17-
1987	23,502	7,352	31		0	7,352-	31-
1988	40,922	9,880	24		0	9,880-	24-
1989	45,150	15,886	35		0	15,886-	35-
1990	18,256	15,088	83		0	15,088-	83-
1991	9,785	46,744	478		0	46,744-	478-
1992	25,423	29,690	117		0	29,690-	117-
1993	8,882	5,186	58		0	5,186-	58-
1994	6,278	2,381	38		0	2,381-	38-
1995	26,696	33,075	124		0	33,075-	124-
1996	47,596	21,610	45		0	21,610-	45-
1997	77,714	74,426	96		0	74,426-	96-
1998	41,059	52,607	128		0	52,607-	128-
1999	60,317	43,513	72		0	43,513-	72-
2000	85,489	113,379	133		0	113,379-	133-
2001	53,805	143,160	266		0	143,160-	266-
2002	38,328	26,830	70		0	26,830-	70-
2003	102,578	86,536	84		0	86,536-	84-
2004	15,636	11,410	73		0	11,410-	73-
2005	72,802	32,567	45		0	32,567-	45-
2006	65,718	113,990	173		0	113,990-	173-
2007	11,321	27,121	240		0	27,121-	240-
2008	89,967	12,500	14		0	12,500-	14-
2009	57,349	21,618	38		0	21,618-	38-
2010	124,362	109,892	88		0	109,892-	88-
2011	11,824	56,938	482		0	56,938-	482-
TOTAL	1,213,493	1,124,046	93		0	1,124,046-	93-
THREE-YEAR MOVING AVERAGES							
83-85	9,941	2,287	23		0	2,287-	23-
84-86	10,674	1,848	17		0	1,848-	17-
85-87	16,096	4,158	26		0	4,158-	26-
86-88	29,111	7,013	24		0	7,013-	24-
87-89	36,525	11,039	30		0	11,039-	30-
88-90	34,776	13,618	39		0	13,618-	39-
89-91	24,397	25,906	106		0	25,906-	106-
90-92	17,821	30,507	171		0	30,507-	171-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 473.00 - POLES, TOWERS AND FIXTURES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	14,697	27,207	185		0	27,207-	185-
92-94	13,528	12,419	92		0	12,419-	92-
93-95	13,952	13,547	97		0	13,547-	97-
94-96	26,857	19,022	71		0	19,022-	71-
95-97	50,669	43,037	85		0	43,037-	85-
96-98	55,456	49,548	89		0	49,548-	89-
97-99	59,697	56,849	95		0	56,849-	95-
98-00	62,288	69,833	112		0	69,833-	112-
99-01	66,537	100,017	150		0	100,017-	150-
00-02	59,207	94,456	160		0	94,456-	160-
01-03	64,904	85,509	132		0	85,509-	132-
02-04	52,181	41,592	80		0	41,592-	80-
03-05	63,672	43,504	68		0	43,504-	68-
04-06	51,385	52,656	102		0	52,656-	102-
05-07	49,947	57,893	116		0	57,893-	116-
06-08	55,669	51,204	92		0	51,204-	92-
07-09	52,879	20,413	39		0	20,413-	39-
08-10	90,559	48,003	53		0	48,003-	53-
09-11	64,512	62,816	97		0	62,816-	97-
FIVE-YEAR AVERAGE							
07-11	58,965	45,614	77		0	45,614-	77-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.00 - OVERHEAD CONDUCTOR - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	4,695	5,047	107		0	5,047-	107-
1984	3,222	181	6		0	181-	6-
1985	1,735	1,242	72		0	1,242-	72-
1986	5,966	4,180	70		0	4,180-	70-
1987	6,180	17,556	284		0	17,556-	284-
1988	8,891	5,511	62		0	5,511-	62-
1989	18,522	12,800	69		0	12,800-	69-
1990	15,824	8,228	52		0	8,228-	52-
1991	3,620	21,364	590		0	21,364-	590-
1992	6,046	11,136	184		0	11,136-	184-
1993	5,173	5,309	103		0	5,309-	103-
1994	1,515	1,316	87		0	1,316-	87-
1995	5,600	4,644	83		0	4,644-	83-
1996	8,691	4,811	55		0	4,811-	55-
1997	19,144	24,656	129		0	24,656-	129-
1998	8,386	16,419	196		0	16,419-	196-
1999	12,271	6,801	55		0	6,801-	55-
2000	14,527	12,330	85		0	12,330-	85-
2001	9,337	14,459	155		0	14,459-	155-
2002	8,187	4,938	60		0	4,938-	60-
2003	59,749	55,901	94		0	55,901-	94-
2004	4,049	2,435	60		0	2,435-	60-
2005	2,976	12,992	437		0	12,992-	437-
2006	974	40,889			0	40,889-	
2007	132	10,846			0	10,846-	
2008	37,893	18,603	49		0	18,603-	49-
2009	388	8,000			0	8,000-	
2010	18,541	8,400	45		0	8,400-	45-
2011	2,687	11,351	422		0	11,351-	422-
TOTAL	294,921	352,345	119		0	352,345-	119-
THREE-YEAR MOVING AVERAGES							
83-85	3,217	2,157	67		0	2,157-	67-
84-86	3,641	1,868	51		0	1,868-	51-
85-87	4,627	7,659	166		0	7,659-	166-
86-88	7,012	9,082	130		0	9,082-	130-
87-89	11,198	11,956	107		0	11,956-	107-
88-90	14,412	8,846	61		0	8,846-	61-
89-91	12,655	14,131	112		0	14,131-	112-
90-92	8,497	13,576	160		0	13,576-	160-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.00 - OVERHEAD CONDUCTOR - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	4,946	12,603	255		0	12,603-	255-
92-94	4,245	5,920	139		0	5,920-	139-
93-95	4,096	3,756	92		0	3,756-	92-
94-96	5,269	3,590	68		0	3,590-	68-
95-97	11,145	11,370	102		0	11,370-	102-
96-98	12,074	15,295	127		0	15,295-	127-
97-99	13,267	15,959	120		0	15,959-	120-
98-00	11,728	11,850	101		0	11,850-	101-
99-01	12,045	11,197	93		0	11,197-	93-
00-02	10,684	10,576	99		0	10,576-	99-
01-03	25,758	25,099	97		0	25,099-	97-
02-04	23,995	21,091	88		0	21,091-	88-
03-05	22,258	23,776	107		0	23,776-	107-
04-06	2,666	18,772	704		0	18,772-	704-
05-07	1,361	21,576			0	21,576-	
06-08	13,000	23,446	180		0	23,446-	180-
07-09	12,804	12,483	97		0	12,483-	97-
08-10	18,941	11,668	62		0	11,668-	62-
09-11	7,205	9,250	128		0	9,250-	128-
FIVE-YEAR AVERAGE							
07-11	11,928	11,440	96		0	11,440-	96-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.10 - OVERHEAD SERVICES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	339		0		0		0
1984	130		0		0		0
1985	130		0		0		0
1986	286		0		0		0
1987							
1988							
1989							
1990							
1991	32		0		0		0
1992							
1993							
1994							
1995							
1996		1,062				1,062-	
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008	16		0	27	169	27	169
2009				81		81	
2010	44,294		0	26	0	26	0
2011	20,219		0		0		0
TOTAL	65,446	1,062	2	134	0	928-	1-
THREE-YEAR MOVING AVERAGES							
83-85	200		0		0		0
84-86	182		0		0		0
85-87	139		0		0		0
86-88	95		0		0		0
87-89							
88-90							
89-91	11		0		0		0
90-92	11		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.10 - OVERHEAD SERVICES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
91-93	11		0		0		0
92-94							
93-95							
94-96		354				354-	
95-97		354				354-	
96-98		354				354-	
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08	5		0	9	169	9	169
07-09	5		0	36	675	36	675
08-10	14,770		0	45	0	45	0
09-11	21,504		0	36	0	36	0
FIVE-YEAR AVERAGE							
07-11	12,906		0	27	0	27	0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.00 - UNDERGROUND CONDUIT - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	193	20	10		0	20-	10-
1986							
1987							
1988	5		0		0		0
1989	9	2	22		0	2-	22-
1990	11		0		0		0
1991	13		0		0		0
1992	483		0		0		0
1993	64		0		0		0
1994	81		0		0		0
1995	908	1,125	124		0	1,125-	124-
1996	252	114	45		0	114-	45-
1997	621	464	75		0	464-	75-
1998	52	33,870			0	33,870-	
1999	2,708	2,159	80		0	2,159-	80-
2000	1,455	1,680	115		0	1,680-	115-
2001	428	317	74		0	317-	74-
2002	328	2,981	909		0	2,981-	909-
2003	525	62,881			0	62,881-	
2004	2,120	23	1		0	23-	1-
2005							
2006	967		0		0		0
2007							
2008		5,211				5,211-	
2009		6,174				6,174-	
2010	1,862	7,500	403		0	7,500-	403-
2011	703	687	98		0	687-	98-
TOTAL	13,788	125,208	908		0	125,208-	908-
THREE-YEAR MOVING AVERAGES							
85-87	64	7	10		0	7-	10-
86-88	2		0		0		0
87-89	5	1	14		0	1-	14-
88-90	8	1	8		0	1-	8-
89-91	11	1	6		0	1-	6-
90-92	169		0		0		0
91-93	187		0		0		0
92-94	209		0		0		0
93-95	351	375	107		0	375-	107-
94-96	414	413	100		0	413-	100-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.00 - UNDERGROUND CONDUIT - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
95-97	594	568	96		0	568-	96-
96-98	308	11,483			0	11,483-	
97-99	1,127	12,164			0	12,164-	
98-00	1,405	12,570	895		0	12,570-	895-
99-01	1,530	1,385	91		0	1,385-	91-
00-02	737	1,659	225		0	1,659-	225-
01-03	427	22,060			0	22,060-	
02-04	991	21,962			0	21,962-	
03-05	882	20,968			0	20,968-	
04-06	1,029	8	1		0	8-	1-
05-07	322		0		0		0
06-08	322	1,737	539		0	1,737-	539-
07-09		3,795				3,795-	
08-10	621	6,295			0	6,295-	
09-11	855	4,787	560		0	4,787-	560-
FIVE-YEAR AVERAGE							
07-11	513	3,914	763		0	3,914-	763-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.10 - UNDERGROUND SERVICES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1991	1		0		0		0
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010	30,641		0		0		0
2011	11,415		0		0		0
TOTAL	42,057		0		0		0
THREE-YEAR MOVING AVERAGES							
91-93			0		0		0
92-94							
93-95							
94-96							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.10 - UNDERGROUND SERVICES - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09							
08-10	10,214		0		0		0
09-11	14,019		0		0		0
FIVE-YEAR AVERAGE							
07-11	8,411		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.10 - METERS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	732		0	507	69	507	69
1984	2,229		0	124	6	124	6
1985			0		0		0
1986	4,325		0		0		0
1987	4,267		0	194	5	194	5
1988	2,624	474	18	565	22	91	3
1989	4,532	671	15	657	14	14-	0
1990	3,817	525	14	326	9	199-	5-
1991	8,977		0	191	2	191	2
1992	7,848	510	6	274	3	236-	3-
1993	11,666		0	193	2	193	2
1994	10,987		0	66	1	66	1
1995	24,254		0		0		0
1996	29,951	300	1	180	1	120-	0
1997	38,738		0	456	1	456	1
1998	22,348	1,273	6		0	1,273-	6-
1999	115,043		0	189	0	189	0
2000	200,267		0	61	0	61	0
2001	94,899		0		0		0
2002	185,973		0	56	0	56	0
2003	140,306	11,049	8	155	0	10,894-	8-
2004	106,016		0		0		0
2005	100,471		0		0		0
2006	48,626		0	50	0	50	0
2007	14,525	3,375	23	3,595	25	220	2
2008	96,496		0		0		0
2009				37		37	
2010	166,427	5,376	3	35,926	22	30,550	18
2011		789		147		642-	
TOTAL	1,446,344	24,343	2	43,949	3	19,606	1
THREE-YEAR MOVING AVERAGES							
83-85	987		0	210	21	210	21
84-86	2,185		0	41	2	41	2
85-87	2,864		0	65	2	65	2
86-88	3,739	158	4	253	7	95	3
87-89	3,808	382	10	472	12	90	2
88-90	3,658	557	15	516	14	41-	1-
89-91	5,775	399	7	391	7	7-	0
90-92	6,881	345	5	264	4	81-	1-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.10 - METERS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	9,497	170	2	219	2	49	1
92-94	10,167	170	2	178	2	8	0
93-95	15,636		0	86	1	86	1
94-96	21,731	100	0	82	0	18-	0
95-97	30,981	100	0	212	1	112	0
96-98	30,346	524	2	212	1	312-	1-
97-99	58,710	424	1	215	0	209-	0
98-00	112,553	424	0	83	0	341-	0
99-01	136,736		0	83	0	83	0
00-02	160,380		0	39	0	39	0
01-03	140,393	3,683	3	70	0	3,613-	3-
02-04	144,098	3,683	3	70	0	3,613-	3-
03-05	115,598	3,683	3	52	0	3,631-	3-
04-06	85,038		0	17	0	17	0
05-07	54,541	1,125	2	1,215	2	90	0
06-08	53,216	1,125	2	1,215	2	90	0
07-09	37,007	1,125	3	1,211	3	86	0
08-10	87,641	1,792	2	11,988	14	10,195	12
09-11	55,476	2,055	4	12,037	22	9,981	18
FIVE-YEAR AVERAGE							
07-11	55,490	1,908	3	7,941	14	6,033	11

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.30 - AMR METERS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2007	14,525		0		0		0
2008							
2009							
2010							
2011							
TOTAL	14,525		0		0		0
THREE-YEAR MOVING AVERAGES							
07-09	4,842		0		0		0
08-10							
09-11							
FIVE-YEAR AVERAGE							
07-11	2,905		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 477.10 - SUBSTATION EQUIPMENT - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	82		0	82	100	82	100
1986	1,791		0	560	31	560	31
1987	1,598		0	1,598	100	1,598	100
1988	7,226		0	312	4	312	4
1989	1,929	600	31		0	600-	31-
1990	21,481	5,700	27	8,124	38	2,424	11
1991	2,331	1,905	82	3	0	1,902-	82-
1992							
1993							
1994							
1995				828		828	
1996							
1997	40	50	125		0	50-	125-
1998							
1999							
2000		9,528		58		9,470-	
2001							
2002							
2003							
2004		152				152-	
2005		100,489				100,489-	
2006		6,240				6,240-	
2007		7,762				7,762-	
2008		9,519				9,519-	
2009		8,547				8,547-	
2010		4,022				4,022-	
2011							
TOTAL	36,478	154,514	424	11,565	32	142,949-	392-
THREE-YEAR MOVING AVERAGES							
85-87	1,157		0	747	65	747	65
86-88	3,538		0	823	23	823	23
87-89	3,584	200	6	637	18	437	12
88-90	10,212	2,100	21	2,812	28	712	7
89-91	8,580	2,735	32	2,709	32	26-	0
90-92	7,937	2,535	32	2,709	34	174	2
91-93	777	635	82	1	0	634-	82-
92-94							
93-95				276		276	
94-96				276		276	

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 477.10 - SUBSTATION EQUIPMENT - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
95-97	13	17	125	276		259	
96-98	13	17	125		0	17-	125-
97-99	13	17	125		0	17-	125-
98-00		3,176		19		3,157-	
99-01		3,176		19		3,157-	
00-02		3,176		19		3,157-	
01-03							
02-04		51				51-	
03-05		33,547				33,547-	
04-06		35,627				35,627-	
05-07		38,164				38,164-	
06-08		7,840				7,840-	
07-09		8,609				8,609-	
08-10		7,363				7,363-	
09-11		4,190				4,190-	
FIVE-YEAR AVERAGE							
07-11		5,970				5,970-	

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.10 - STREET LIGHTS AND SIGNAL SYSTEMS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	6,280		0		0		0
1984	3,205		0		0		0
1985	9,881		0		0		0
1986	13,540		0		0		0
1987	433,260		0		0		0
1988	39,203		0		0		0
1989	33,400		0		0		0
1990	4,542		0		0		0
1991	705		0		0		0
1992	3,214		0		0		0
1993	1,304		0		0		0
1994	2,495		0		0		0
1995	1,239		0	25	2	25	2
1996	3,797	866	23	804	21	62-	2-
1997	16,117	14,758	92	1,250	8	13,508-	84-
1998	5,155	8,178	159	1,341	26	6,837-	133-
1999	4,049	1,147	28	8	0	1,139-	28-
2000	7,272	3,651	50	100	1	3,551-	49-
2001	11,919	15,075	126	1,018	9	14,057-	118-
2002	127	162	128	229	180	67	53
2003	25,297	2,439	10	551	2	1,888-	7-
2004	11,383	750	7		0	750-	7-
2005	5,110	1,054	21	117	2	937-	18-
2006	5,302	7,164	135	1,156	22	6,008-	113-
2007	4,493	594	13	1,028	23	434	10
2008	963		0	960	100	960	100
2009	2,195	1,934	88	556	25	1,378-	63-
2010	7,288	13,390	184	49	1	13,341-	183-
2011	6,524	17,293	265	995	15	16,298-	250-
TOTAL	669,259	88,455	13	10,187	2	78,268-	12-
THREE-YEAR MOVING AVERAGES							
83-85	6,455		0		0		0
84-86	8,875		0		0		0
85-87	152,227		0		0		0
86-88	162,001		0		0		0
87-89	168,621		0		0		0
88-90	25,715		0		0		0
89-91	12,882		0		0		0
90-92	2,820		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.10 - STREET LIGHTS AND SIGNAL SYSTEMS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	1,741		0		0		0
92-94	2,338		0		0		0
93-95	1,679		0	8	0	8	0
94-96	2,510	289	11	276	11	12-	0
95-97	7,051	5,208	74	693	10	4,515-	64-
96-98	8,356	7,934	95	1,132	14	6,802-	81-
97-99	8,440	8,028	95	866	10	7,161-	85-
98-00	5,492	4,325	79	483	9	3,842-	70-
99-01	7,747	6,624	86	375	5	6,249-	81-
00-02	6,439	6,296	98	449	7	5,847-	91-
01-03	12,448	5,892	47	599	5	5,293-	43-
02-04	12,269	1,117	9	260	2	857-	7-
03-05	13,930	1,414	10	223	2	1,192-	9-
04-06	7,265	2,989	41	424	6	2,565-	35-
05-07	4,968	2,937	59	767	15	2,170-	44-
06-08	3,586	2,586	72	1,048	29	1,538-	43-
07-09	2,550	843	33	848	33	5	0
08-10	3,482	5,108	147	522	15	4,586-	132-
09-11	5,336	10,872	204	533	10	10,339-	194-
FIVE-YEAR AVERAGE							
07-11	4,293	6,642	155	718	17	5,925-	138-

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.20 - SENTINEL LIGHTS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	9,341	1,820	19	8,405	90	6,585	70
1984	4,476	674	15	5,464	122	4,790	107
1985	2,601	101	4	2,792	107	2,691	103
1986	7,458	1,219	16	13,112	176	11,893	159
1987	3,051		0	1,950	64	1,950	64
1988	2,486	128	5	1,261	51	1,133	46
1989	565	139	25	423	75	284	50
1990							
1991							
1992	560		0	346	62	346	62
1993							
1994	936	4,130	441	468	50	3,662-	391-
1995	83		0		0		0
1996							
1997							
1998							
1999							
2000		131				131-	
2001		1,483				1,483-	
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
TOTAL	31,557	9,825	31	34,221	108	24,396	77
THREE-YEAR MOVING AVERAGES							
83-85	5,473	865	16	5,554	101	4,689	86
84-86	4,845	665	14	7,123	147	6,458	133
85-87	4,370	440	10	5,951	136	5,511	126
86-88	4,332	449	10	5,441	126	4,992	115
87-89	2,034	89	4	1,211	60	1,122	55
88-90	1,017	89	9	561	55	472	46
89-91	188	46	25	141	75	95	50
90-92	187		0	115	62	115	62

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.20 - SENTINEL LIGHTS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
91-93	187		0	115	62	115	62
92-94	499	1,377	276	271	54	1,105-	222-
93-95	340	1,377	405	156	46	1,221-	359-
94-96	340	1,377	405	156	46	1,221-	359-
95-97	28		0		0		0
96-98							
97-99							
98-00		44				44-	
99-01		538				538-	
00-02		538				538-	
01-03		494				494-	
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11							
FIVE-YEAR AVERAGE							
07-11							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 479.10 - LINE TRANSFORMERS - DISTRIBUTION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	9,037	1,864	21	216	2	1,648-	18-
1996	4,704	1,665	35	12,154	258	10,489	223
1997	13,006	14,315	110	6,217	48	8,098-	62-
1998	16,313	102,096	626	43,956	269	58,140-	356-
1999	22,755	18,376	81	4,927	22	13,449-	59-
2000	5,299	36,373	686	1,632	31	34,741-	656-
2001	6,332	85,733		499	8	85,234-	
2002	4,381	64,644		4,313	98	60,331-	
2003	50,239	96,478	192	1,666	3	94,812-	189-
2004	2,646	21,106	798	2,520	95	18,586-	702-
2005	15,096	1,157	8	10,201	68	9,044	60
2006	18,276	6,720	37	7,943	43	1,223	7
2007	2,609	4,872	187	14,690	563	9,818	376
2008	3,275	2,914	89	27,924	853	25,010	764
2009	2,605	3,777	145	10,319	396	6,542	251
2010	29,655	31,563	106	17,262	58	14,301-	48-
2011	20,596	8,792	43	3,893	19	4,899-	24-
TOTAL	226,824	502,445	222	170,332	75	332,113-	146-
THREE-YEAR MOVING AVERAGES							
95-97	8,916	5,948	67	6,196	69	248	3
96-98	11,341	39,359	347	20,776	183	18,583-	164-
97-99	17,358	44,929	259	18,367	106	26,562-	153-
98-00	14,789	52,282	354	16,838	114	35,443-	240-
99-01	11,462	46,827	409	2,353	21	44,475-	388-
00-02	5,337	62,250		2,148	40	60,102-	
01-03	20,317	82,285	405	2,159	11	80,126-	394-
02-04	19,089	60,743	318	2,833	15	57,910-	303-
03-05	22,660	39,580	175	4,796	21	34,785-	154-
04-06	12,006	9,661	80	6,888	57	2,773-	23-
05-07	11,994	4,250	35	10,945	91	6,695	56
06-08	8,053	4,835	60	16,852	209	12,017	149
07-09	2,830	3,854	136	17,644	624	13,790	487
08-10	11,845	12,751	108	18,502	156	5,750	49
09-11	17,619	14,711	83	10,491	60	4,219-	24-
FIVE-YEAR AVERAGE							
07-11	11,748	10,384	88	14,818	126	4,434	38

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 482.00 - STRUCTURES AND IMPROVEMENTS - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	1,522		0		0		0
1989							
1990							
1991							
1992	201,929		0		0		0
1993							
1994							
1995	553		0		0		0
1996							
1997							
1998							
1999							
2000		3,073				3,073-	
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
TOTAL	204,004	3,073	2		0	3,073-	2-
THREE-YEAR MOVING AVERAGES							
88-90	507		0		0		0
89-91							
90-92	67,310		0		0		0
91-93	67,310		0		0		0
92-94	67,310		0		0		0
93-95	184		0		0		0
94-96	184		0		0		0
95-97	184		0		0		0
96-98							
97-99							
98-00		1,024				1,024-	
99-01		1,024				1,024-	
00-02		1,024				1,024-	

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 482.00 - STRUCTURES AND IMPROVEMENTS - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
08-10							
09-11							
FIVE-YEAR AVERAGE							
07-11							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.00 - OFFICE FURNITURE AND EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	4,052		0		0		0
1984	3,091		0		0		0
1985	3,263		0		0		0
1986	3,267		0		0		0
1987	2,204		0		0		0
1988	2,776		0		0		0
1989	2,174		0		0		0
1990	2,382		0		0		0
1991	2,549		0		0		0
1992	5,458		0		0		0
1993	2,133		0		0		0
1994	2,834		0		0		0
1995	6,427		0		0		0
1996	5,853		0		0		0
1997	8,315		0		0		0
1998	19,018		0		0		0
1999	15,451		0		0		0
2000	12,718		0		0		0
2001	24,992		0		0		0
2002	29,239		0		0		0
2003							
2004							
2005	44,720		0		0		0
2006	42,433		0		0		0
2007	38,554		0		0		0
2008	37,619		0		0		0
2009	33,982		0		0		0
2010	28,435		0		0		0
2011	15,493	480	3		0	480-	3-
TOTAL	399,432	480	0		0	480-	0
THREE-YEAR MOVING AVERAGES							
83-85	3,469		0		0		0
84-86	3,207		0		0		0
85-87	2,911		0		0		0
86-88	2,749		0		0		0
87-89	2,385		0		0		0
88-90	2,444		0		0		0
89-91	2,368		0		0		0
90-92	3,463		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.00 - OFFICE FURNITURE AND EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
91-93	3,380		0		0		0
92-94	3,475		0		0		0
93-95	3,798		0		0		0
94-96	5,038		0		0		0
95-97	6,865		0		0		0
96-98	11,062		0		0		0
97-99	14,261		0		0		0
98-00	15,729		0		0		0
99-01	17,720		0		0		0
00-02	22,316		0		0		0
01-03	18,077		0		0		0
02-04	9,746		0		0		0
03-05	14,907		0		0		0
04-06	29,051		0		0		0
05-07	41,902		0		0		0
06-08	39,535		0		0		0
07-09	36,718		0		0		0
08-10	33,345		0		0		0
09-11	25,970	160	1		0	160-	1-
FIVE-YEAR AVERAGE							
07-11	30,817	96	0		0	96-	0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.20 - COMPUTER EQUIPMENT AND ACCESSORIES - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1992	17,410		0	17,410	100	17,410	100
1993							
1994	4,325		0		0		0
1995							
1996	67,348		0		0		0
1997	46,612		0		0		0
1998	26,506		0		0		0
1999	343,720		0	21,910	6	21,910	6
2000	20,522		0		0		0
2001	727		0		0		0
2002	3,013		0		0		0
2003							
2004							
2005	180		0		0		0
2006	557		0		0		0
2007	2,327		0		0		0
2008	6,406		0		0		0
2009	23,287		0		0		0
2010	4,631		0		0		0
2011	75		0		0		0
TOTAL	567,646		0	39,320	7	39,320	7
THREE-YEAR MOVING AVERAGES							
92-94	7,245		0	5,803	80	5,803	80
93-95	1,442		0		0		0
94-96	23,891		0		0		0
95-97	37,987		0		0		0
96-98	46,822		0		0		0
97-99	138,946		0	7,303	5	7,303	5
98-00	130,249		0	7,303	6	7,303	6
99-01	121,656		0	7,303	6	7,303	6
00-02	8,087		0		0		0
01-03	1,247		0		0		0
02-04	1,004		0		0		0
03-05	60		0		0		0
04-06	246		0		0		0
05-07	1,021		0		0		0
06-08	3,097		0		0		0
07-09	10,673		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.20 - COMPUTER EQUIPMENT AND ACCESSORIES - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
08-10	11,441		0		0		0
09-11	9,331		0		0		0
FIVE-YEAR AVERAGE							
07-11	7,345		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 484.00 - TRANSPORTATION AND MOBILE EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	24,215		0		0		0
1986	26,522		0		0		0
1987							
1988	65,055		0		0		0
1989	84,427		0		0		0
1990	76,111		0		0		0
1991	81,810		0		0		0
1992	192,122		0		0		0
1993	203,197		0		0		0
1994	174,850		0		0		0
1995							
1996	150,825		0		0		0
1997	31,796		0		0		0
1998	676,007		0	301,323	45	301,323	45
1999	74,875		0	14,110	19	14,110	19
2000	86,082		0	10,751	12	10,751	12
2001	97,684		0	11,801	12	11,801	12
2002	168,240		0	26,306	16	26,306	16
2003							
2004							
2005							
2006							
2007	288,535		0	73,754	26	73,754	26
2008	44,179		0	41,097	93	41,097	93
2009	108,229		0	73,754	68	73,754	68
2010	154,051		0	6,845	4	6,845	4
2011	4,517	1	0	18,389	407	18,388	407
TOTAL	2,813,329	1	0	578,130	21	578,129	21
THREE-YEAR MOVING AVERAGES							
85-87	16,912		0		0		0
86-88	30,526		0		0		0
87-89	49,827		0		0		0
88-90	75,198		0		0		0
89-91	80,783		0		0		0
90-92	116,681		0		0		0
91-93	159,043		0		0		0
92-94	190,056		0		0		0
93-95	126,016		0		0		0
94-96	108,558		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 484.00 - TRANSPORTATION AND MOBILE EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
95-97	60,874		0		0		0
96-98	286,209		0	100,441	35	100,441	35
97-99	260,893		0	105,144	40	105,144	40
98-00	278,988		0	108,728	39	108,728	39
99-01	86,214		0	12,221	14	12,221	14
00-02	117,335		0	16,286	14	16,286	14
01-03	88,641		0	12,702	14	12,702	14
02-04	56,080		0	8,769	16	8,769	16
03-05							
04-06							
05-07	96,178		0	24,585	26	24,585	26
06-08	110,905		0	38,284	35	38,284	35
07-09	146,981		0	62,868	43	62,868	43
08-10	102,153		0	40,565	40	40,565	40
09-11	88,932		0	32,996	37	32,996	37
FIVE-YEAR AVERAGE							
07-11	119,902		0	42,768	36	42,768	36

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 485.00 - TOOLS AND INSTRUMENTS - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1983	8,303		0		0		0
1984	6,420		0		0		0
1985	5,784		0		0		0
1986	5,843		0		0		0
1987	6,007		0		0		0
1988	12,250		0		0		0
1989	7,861		0		0		0
1990	8,354		0		0		0
1991	8,840		0		0		0
1992	10,597		0		0		0
1993	13,925		0	1,719	12	1,719	12
1994	15,518		0		0		0
1995	20,961		0		0		0
1996	31,992		0		0		0
1997	40,489		0		0		0
1998	32,789		0		0		0
1999	60,294		0		0		0
2000	64,833		0		0		0
2001	65,652		0		0		0
2002	63,347		0		0		0
2003							
2004							
2005	60,771		0		0		0
2006	59,357		0		0		0
2007	60,900		0		0		0
2008	59,576		0		0		0
2009	18,467		0		0		0
2010	16,729		0		0		0
2011	12,754		0		0		0
TOTAL	778,613		0	1,719	0	1,719	0
THREE-YEAR MOVING AVERAGES							
83-85	6,836		0		0		0
84-86	6,016		0		0		0
85-87	5,878		0		0		0
86-88	8,033		0		0		0
87-89	8,706		0		0		0
88-90	9,488		0		0		0
89-91	8,352		0		0		0
90-92	9,264		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 485.00 - TOOLS AND INSTRUMENTS - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
91-93	11,121		0	573	5	573	5
92-94	13,347		0	573	4	573	4
93-95	16,801		0	573	3	573	3
94-96	22,824		0		0		0
95-97	31,147		0		0		0
96-98	35,090		0		0		0
97-99	44,524		0		0		0
98-00	52,639		0		0		0
99-01	63,593		0		0		0
00-02	64,611		0		0		0
01-03	43,000		0		0		0
02-04	21,116		0		0		0
03-05	20,257		0		0		0
04-06	40,043		0		0		0
05-07	60,343		0		0		0
06-08	59,944		0		0		0
07-09	46,314		0		0		0
08-10	31,591		0		0		0
09-11	15,983		0		0		0
FIVE-YEAR AVERAGE							
07-11	33,685		0		0		0

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 486.00 - COMMUNICATION EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1992	20,000		0	1,749	9	1,749	9
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000	28,110		0		0		0
2001							
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
TOTAL	48,110		0	1,749	4	1,749	4
THREE-YEAR MOVING AVERAGES							
92-94	6,667		0	583	9	583	9
93-95							
94-96							
95-97							
96-98							
97-99							
98-00	9,370		0		0		0
99-01	9,370		0		0		0
00-02	9,370		0		0		0
01-03							
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 486.00 - COMMUNICATION EQUIPMENT - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
08-10							
09-11							
FIVE-YEAR AVERAGE							
07-11							

3/19/2013

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 488.20 - HOUSES - GENERAL PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT

YUKON ELECTRICAL COMPANY LIMITED

CALCULATION MONTH AND YEAR	12/31/2011
STARTING FISCAL YEAR VINTAGE	1945
EQUIVALENT IN-SERVICE MONTH	6.00
CALCULATION PROCEDURE	EqualLifeGroup
MINIMUM EXPECTANCY	0.00
REMAINING LIFE	WholeLife
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 422.00 - HYDRO STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1987	67,520.32	1.74	1,292.34	0.4263	31,662
1989	57,730.91	1.79	1,136.72	0.4028	25,579
1991	308.57	1.85	6.28	0.3792	129
1992	11,156.06	1.88	230.71	0.3666	4,499
2000	10,832.25	2.16	257.37	0.2484	2,960
2011	67,738.02	3.05	2,272.61	0.0152	1,133
	215,286.13		5,196.03		65,962

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.41

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 423.00 - HYDRO RESEVOIRS, DAMS AND WATERWAYS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
INTERIM SURVIVOR CURVE.. IOWA 103-R3					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1987	454,475.11	1.58	7,898.78	0.3871	193,520
1989	48,551.65	1.63	870.53	0.3668	19,590
1992	2,414.61	1.71	45.42	0.3334	886
1993	134,389.31	1.74	2,572.21	0.3219	47,586
1996	24,178.48	1.82	484.05	0.2821	7,503
1997	36,567.29	1.86	748.17	0.2697	10,848
2002	11,519.73	2.04	258.50	0.1938	2,456
2003	2,788.31	2.08	63.80	0.1768	542
2004	42,198.95	2.12	984.08	0.1590	7,381
2005	111,863.49	2.16	2,657.88	0.1404	17,276
2007	98,112.46	2.26	2,439.08	0.1017	10,976
2008	39,046.90	2.31	992.18	0.0808	3,470
2010	547,634.36	2.43	14,638.27	0.0364	21,927
2011	321,332.38	2.50	8,836.64	0.0125	4,418
	1,875,073.03		43,489.59		348,379

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.32

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 425.00 - HYDRO GENERATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
INTERIM SURVIVOR CURVE.. IOWA 85-R3					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1987	179,228.52	1.63	3,213.57	0.3994	78,742
2000	89,900.44	1.99	1,967.92	0.2288	22,626
2001	3,500.40	2.03	78.16	0.2132	821
2008	318,629.07	2.34	8,201.51	0.0819	28,705
2009	124,172.24	2.40	3,278.15	0.0600	8,195
2010	723,837.35	2.46	19,587.04	0.0369	29,381
2011	19,166.87	2.54	535.52	0.0127	268
	1,458,434.89		36,861.87		168,738

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.53

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 426.00 - HYDRO ACCESSORY AND ELECTRICAL EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
INTERIM SURVIVOR CURVE.. IOWA 45-R3					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1987	62,699.91	2.24	1,544.93	0.5488	37,851
1991	12,366.51	2.31	314.23	0.4736	6,442
2000	12,896.50	2.48	351.82	0.2852	4,046
2001	17,229.29	2.51	475.70	0.2636	4,996
	105,192.21		2,686.68		53,335

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.55

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 427.00 - HYDRO MISCELLANEOUS EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
INTERIM SURVIVOR CURVE.. IOWA 30-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1987	3,300.00	2.90	105.27	0.7105	2,579
1990	1,347.72	3.03	44.92	0.6514	966
1992	1,522.97	3.12	52.27	0.6084	1,019
1993	17,813.77	3.17	621.17	0.5864	11,491
2008	3,364.92	4.11	152.13	0.1438	532
2009	41,307.32	4.25	1,931.12	0.1062	4,826
	68,656.70		2,906.88		21,413

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.23

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
BEAVER CREEK					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	9,162.03	2.04	205.60	0.8262	8,327
1986	22,121.90	2.40	584.02	0.6120	14,892
1991	352.47	2.52	9.77	0.5166	200
2006	5,851.48	2.99	192.46	0.1644	1,058
	37,487.88		991.85		24,477
CARMACKS					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	5,170.46	2.04	116.03	0.8262	4,699
1993	32,889.08	2.57	929.77	0.4754	17,199
1997	12,049.89	2.67	353.91	0.3872	5,132
2005	11,904.48	2.94	384.99	0.1911	2,502
2006	105,725.03	2.99	3,477.30	0.1644	19,119
	167,738.94		5,262.00		48,651
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. -10					
1971	22,662.51	2.09	521.01	0.8464	21,100
1985	13,952.01	2.73	418.98	0.7234	11,102
1991	352.46	3.20	12.41	0.6560	254
2006	5,314.95	5.87	343.19	0.3228	1,887
	42,281.93		1,295.59		34,343
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	59,126.21	2.04	1,326.79	0.8262	53,735
1976	1,003.99	2.16	23.85	0.7668	847
1992	258.00	2.54	7.21	0.4953	141
1997	9,866.63	2.67	289.78	0.3872	4,202
2007	181,455.77	3.04	6,067.88	0.1368	27,305

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
2008	322,680.35	3.10	11,003.40	0.1085	38,512
2009	25,330.54	3.18	886.06	0.0795	2,215
2011	8,750.60	3.50	336.90	0.0175	168
	608,472.09		19,941.87		127,125
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	16,476.40	2.04	369.73	0.8262	14,974
1982	31,174.06	2.31	792.13	0.6814	23,366
1983	42,062.15	2.33	1,078.05	0.6640	30,722
1989	21,819.59	2.47	592.84	0.5558	13,340
1991	352.47	2.52	9.77	0.5166	200
1992	9,774.53	2.54	273.10	0.4953	5,325
1996	8,908.07	2.65	259.67	0.4108	4,025
1997	4,623.41	2.67	135.79	0.3872	1,969
1998	38,405.22	2.70	1,140.64	0.3645	15,399
2005	9,871.42	2.94	319.24	0.1911	2,075
2006	4,432.86	2.99	145.80	0.1644	802
	187,900.18		5,116.76		112,197
PELLY CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2033					
NET SALVAGE PERCENT.. -10					
1971	8,362.86	2.04	187.66	0.8262	7,600
1976	9,888.00	2.18	237.11	0.7739	8,418
1982	12,270.68	2.35	317.20	0.6932	9,357
1988	17,015.74	2.57	481.03	0.6040	11,305
1991	352.47	2.70	10.47	0.5535	215
2004	1,001.91	3.72	41.00	0.2790	307
	48,891.66		1,274.47		37,202

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	10,571.03	2.04	237.21	0.8262	9,607
1974	8,707.10	2.11	202.09	0.7912	7,578
1976	4,684.35	2.16	111.30	0.7668	3,951
1978	170.40	2.21	4.14	0.7404	139
1989	8,000.00	2.47	217.36	0.5558	4,891
1992	109.38	2.54	3.06	0.4953	60
1993	22,783.19	2.57	644.08	0.4754	11,914
1997	16,193.47	2.67	475.60	0.3872	6,897
2006	100,002.48	2.99	3,289.08	0.1644	18,084
	171,221.40		5,183.92		63,121
STEWART CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	6,882.44	2.04	154.44	0.8262	6,255
1982	11,893.33	2.31	302.21	0.6814	8,915
1988	14,778.07	2.45	398.27	0.5758	9,360
1993	3,486.70	2.57	98.57	0.4754	1,823
2005	210,924.97	2.94	6,821.31	0.1911	44,339
	247,965.51		7,774.80		70,692
SWIFT RIVER					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	4,531.30	2.04	101.68	0.8262	4,118
1998	15,739.26	2.70	467.46	0.3645	6,311
2005	2,232.71	2.94	72.21	0.1911	469
	22,503.27		641.35		10,898

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 442.00 - STRUCTURES AND IMPROVEMENTS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
TESLIN					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	10,350.29	2.04	232.26	0.8262	9,407
2005	8,079.46	2.94	261.29	0.1911	1,698
2011	19,556.13	3.50	752.91	0.0175	376
	37,985.88		1,246.46		11,481
WATSON LAKE					
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5					
PROBABLE RETIREMENT YEAR.. 12-2113					
NET SALVAGE PERCENT.. -10					
1987	311,360.32	2.43	8,322.66	0.5954	203,922
1988	7,591.41	2.45	204.59	0.5758	4,808
1997	10,471.46	2.66	306.39	0.3857	4,443
1999	29,783.20	2.71	887.84	0.3388	11,100
2001	186.47	2.76	5.66	0.2898	59
	359,392.86		9,727.14		224,332
MOBILES					
SURVIVOR CURVE.. IOWA 40-R2.5					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	2.04	239.26	0.8262	9,690
	10,662.39		239.26		9,690
	1,942,503.99		58,695.47		774,209

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.02

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
BEAVER CREEK					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1971	6,791.94	2.30	187.46	0.9315	7,592
1986	7,089.08	2.79	237.34	0.7114	6,052
1994	1,140.87	2.94	40.25	0.5145	704
1996	5,470.27	2.97	194.96	0.4604	3,022
1998	55,480.02	2.99	1,990.62	0.4036	26,870
2004	16,886.36	3.02	611.96	0.2265	4,590
	92,858.54		3,262.59		48,830
CARMACKS					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1973	196.46	2.38	5.61	0.9163	216
1990	40,197.77	2.88	1,389.23	0.6192	29,869
	40,394.23		1,394.84		30,085
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. -20					
1973	3,283.83	2.38	93.79	0.9163	3,611
1997	63,293.96	3.87	2,939.37	0.5612	42,625
1999	16,409.95	4.16	819.18	0.5200	10,240
2003	1,332.07	4.93	78.81	0.4190	670
2004	3,051.15	5.17	189.29	0.3878	1,420
2005	14,133.96	5.44	922.66	0.3536	5,997
2008	1,140.87	6.48	88.71	0.2268	310
2009	2,832.53	6.92	235.21	0.1730	588
	105,478.32		5,367.02		65,461
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1982	100.00	2.68	3.22	0.7906	95
1994	397,144.70	2.94	14,011.27	0.5145	245,197

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1998	68,555.35	2.99	2,459.77	0.4036	33,203
2004	4,343.08	3.02	157.39	0.2265	1,180
2008	148,989.27	3.04	5,435.13	0.1064	19,023
	619,132.40		22,066.78		298,698
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1971	1,829.28	2.30	50.49	0.9315	2,045
1973	18,132.52	2.38	517.86	0.9163	19,938
1985	8,400.29	2.76	278.22	0.7314	7,373
1994	52,075.44	2.94	1,837.22	0.5145	32,151
2003	86,979.73	3.02	3,152.15	0.2567	26,793
2004	1,140.87	3.02	41.35	0.2265	310
2005	46,528.71	3.02	1,686.20	0.1963	10,960
	215,086.84		7,563.49		99,570
PELLY CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2033					
NET SALVAGE PERCENT.. -20					
1971	87,626.71	2.30	2,418.50	0.9315	97,949
1994	7,779.75	3.00	280.07	0.5250	4,901
2003	7,023.17	3.49	294.13	0.2966	2,500
2005	13,194.21	3.68	582.66	0.2392	3,787
2008	13,678.17	4.05	664.76	0.1418	2,327
	129,302.01		4,240.12		111,464
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1986	293.14	2.79	9.81	0.7114	250
1994	1,005.32	2.94	35.47	0.5145	621

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1996	9,000.00	2.97	320.76	0.4604	4,972
1998	60,463.08	2.99	2,169.42	0.4036	29,283
2003	14,364.08	3.02	520.55	0.2567	4,425
	85,125.62		3,056.01		39,551
STEWART CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1971	2,790.21	2.30	77.01	0.9315	3,119
1993	8,091.37	2.93	284.49	0.5420	5,263
2004	27,639.59	3.02	1,001.66	0.2265	7,512
2008	14,000.48	3.04	510.74	0.1064	1,788
2011	12,585.49	3.06	462.14	0.0153	231
	65,107.14		2,336.04		17,913
SWIFT RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
1971	1,005.32	2.30	27.75	0.9315	1,124
1973	936.21	2.38	26.74	0.9163	1,029
1990	41,465.54	2.88	1,433.05	0.6192	30,811
1994	19,118.51	2.94	674.50	0.5145	11,804
1999	904.44	2.99	32.45	0.3738	406
	63,430.02		2,194.49		45,174
TESLIN					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -20					
2004	99,862.71	3.02	3,619.02	0.2265	27,143
	99,862.71		3,619.02		27,143

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 444.00 - FUEL HOLDERS, PRODUCTS AND ACCESSORIES - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
WATSON LAKE					
INTERIM SURVIVOR CURVE.. IOWA 35-R4					
PROBABLE RETIREMENT YEAR.. 12-2113					
NET SALVAGE PERCENT.. -20					
1971	506.33	2.30	13.97	0.9315	566
1976	4,412.77	2.49	131.85	0.8840	4,681
1982	22,767.10	2.68	732.19	0.7906	21,600
1997	21,824.31	2.98	780.44	0.4321	11,316
1999	78,464.70	2.99	2,815.31	0.3738	35,196
2009	619,842.35	3.03	22,537.47	0.0758	56,381
	747,817.56		27,011.23		129,740
MOBILES					
SURVIVOR CURVE.. IOWA 35-R4					
NET SALVAGE PERCENT.. -20					
1988	25,562.13	2.83	868.09	0.6650	20,399
	25,562.13		868.09		20,399
	2,289,157.52		82,979.72		934,028

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.62

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
BEAVER CREEK					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1983	6,729.90	3.02	223.57	0.8607	6,372
1988	35,130.86	3.37	1,302.30	0.7920	30,606
1989	38,776.08	3.44	1,467.29	0.7740	33,014
1991	197,994.87	3.58	7,797.04	0.7339	159,839
1992	2,889.71	3.65	116.02	0.7118	2,263
1993	147,926.58	3.72	6,053.16	0.6882	111,983
1994	51,495.19	3.78	2,141.17	0.6615	37,470
2000	13,621.40	4.09	612.83	0.4704	7,048
2003	29,551.12	4.18	1,358.76	0.3553	11,549
2004	11,663.55	4.20	538.86	0.3150	4,041
	535,779.26		21,611.00		404,185
CARMACKS					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1974	6,707.49	2.50	184.46	0.9375	6,917
1991	411,404.53	3.58	16,201.11	0.7339	332,123
1992	1,431.15	3.65	57.46	0.7118	1,121
	419,543.17		16,443.03		340,161
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. -10					
1971	13,213.83	2.35	341.58	0.9518	13,835
1972	1,165.50	2.40	30.77	0.9480	1,215
1982	5,500.00	2.96	179.08	0.8732	5,283
1993	108,995.02	3.84	4,603.95	0.7104	85,173
2004	81,212.35	5.40	4,824.01	0.4050	36,180
2011	277,989.71	8.07	24,677.15	0.0404	12,354
	488,076.41		34,656.54		154,040

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1974	1,126.47	2.50	30.98	0.9375	1,162
1981	2,086.28	2.89	66.32	0.8814	2,023
1996	56,883.75	3.90	2,440.31	0.6045	37,825
	60,096.50		2,537.61		41,010
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1992	115,345.02	3.65	4,631.10	0.7118	90,313
1993	31,348.63	3.72	1,282.79	0.6882	23,732
1994	115,469.41	3.78	4,801.22	0.6615	84,021
1998	239,200.48	4.01	10,551.13	0.5414	142,453
2004	692,044.84	4.20	31,972.47	0.3150	239,794
2010	30,304.59	4.25	1,416.74	0.0638	2,127
	1,223,712.97		54,655.45		582,440
PELLY CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2033					
NET SALVAGE PERCENT.. -10					
1983	31,559.61	3.02	1,048.41	0.8607	29,880
1991	198,327.99	3.58	7,810.16	0.7339	160,108
1992	1,215.45	3.65	48.80	0.7118	952
1997	114,594.28	3.97	5,004.33	0.5756	72,557
1999	102,441.44	4.08	4,597.57	0.5100	57,470
2000	12.01	4.14	0.55	0.4761	6
2003	13,614.56	4.29	642.47	0.3646	5,460
2004	12,290.60	4.34	586.75	0.3255	4,401
	474,055.94		19,739.04		330,834

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	65.02	2.35	1.68	0.9518	68
1977	4,145.37	2.66	121.29	0.9177	4,185
1989	180,866.60	3.44	6,843.99	0.7740	153,990
1990	294.78	3.51	11.38	0.7546	245
1993	4,381.38	3.72	179.29	0.6882	3,317
	189,753.15		7,157.63		161,805
STEWART CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1971	3,852.20	2.35	99.58	0.9518	4,033
1972	1,061.34	2.40	28.02	0.9480	1,107
1974	5,934.12	2.50	163.19	0.9375	6,120
1985	1,157.99	3.16	40.25	0.8374	1,067
1986	16.33	3.23	0.58	0.8236	15
1988	4,271.69	3.37	158.35	0.7920	3,721
2003	24,500.84	4.18	1,126.55	0.3553	9,576
2004	4,882.86	4.20	225.59	0.3150	1,692
	45,677.37		1,842.11		27,331
SWIFT RIVER					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1970	9,236.40	2.31	234.70	0.9586	9,739
1991	5,179.53	3.58	203.97	0.7339	4,181
1992	25,847.73	3.65	1,037.79	0.7118	20,238
1998	59,650.02	4.01	2,631.16	0.5414	35,524
2003	79,944.14	4.18	3,675.83	0.3553	31,245
2004	2,700.87	4.20	124.78	0.3150	936
2009	58,488.49	4.25	2,734.34	0.1062	6,833
	241,047.18		10,642.57		108,696

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
TESLIN					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. -10					
1993	762,033.60	3.72	31,182.41	0.6882	576,875
	762,033.60		31,182.41		576,875
WATSON LAKE					
INTERIM SURVIVOR CURVE.. IOWA 26-S2.5					
PROBABLE RETIREMENT YEAR.. 12-2113					
NET SALVAGE PERCENT.. -10					
1973	11,370.97	2.45	306.45	0.9432	11,798
1978	2,815.04	2.71	83.92	0.9078	2,811
1981	7,682.30	2.89	244.22	0.8814	7,448
1985	589,119.42	3.16	20,477.79	0.8374	542,661
1986	1,654.02	3.23	58.77	0.8236	1,498
1987	70,000.00	3.30	2,541.00	0.8085	62,254
1989	8,785.44	3.44	332.44	0.7740	7,480
1991	377,412.18	3.58	14,862.49	0.7339	304,681
1993	48,060.52	3.72	1,966.64	0.6882	36,383
1996	250,658.18	3.90	10,753.24	0.6045	166,675
1999	516,871.37	4.05	23,026.62	0.5062	287,804
2000	19,585.15	4.09	881.14	0.4704	10,134
2002	6,723.20	4.16	307.65	0.3952	2,923
2011	258,457.58	4.25	12,082.89	0.0212	6,027
	2,169,195.37		87,925.26		1,450,577
MOBILES					
SURVIVOR CURVE.. IOWA 26-S2.5					
NET SALVAGE PERCENT.. -10					
1982	2,314.53	2.96	75.36	0.8732	2,223
1984	6,948.44	3.09	236.18	0.8498	6,495
1986	52,884.26	3.23	1,878.98	0.8236	47,911
1987	155.25	3.30	5.64	0.8085	138
1988	11,501.98	3.37	426.38	0.7920	10,021
1989	17,870.50	3.44	676.22	0.7740	15,215
1990	155,054.72	3.51	5,986.66	0.7546	128,705
1991	52,410.38	3.58	2,063.92	0.7339	42,310

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 445.00 - GENERAL EQUIPMENT AND PRIME MOVERS - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
MOBILES					
SURVIVOR CURVE.. IOWA 26-S2.5					
NET SALVAGE PERCENT.. -10					
1998	106,050.80	4.01	4,677.90	0.5414	63,157
1999	12,279.04	4.05	547.03	0.5062	6,837
2010	151,030.51	4.25	7,060.68	0.0638	10,599
	568,500.41		23,634.95		333,611
	7,177,471.33		312,027.60		4,511,565

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.35

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
BEAVER CREEK					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	3,820.66	2.22	84.82	0.8991	3,435
1972	342.83	2.25	7.71	0.8888	305
1974	126.08	2.32	2.93	0.8700	110
1977	161.28	2.42	3.90	0.8349	135
1980	1,172.29	2.52	29.54	0.7938	931
1983	3,521.61	2.62	92.27	0.7467	2,630
1992	27,277.24	2.87	782.86	0.5596	15,264
1994	144.34	2.92	4.21	0.5110	74
1998	11,389.22	3.02	343.95	0.4077	4,643
1999	27,540.86	3.04	837.24	0.3800	10,466
2000	7,962.35	3.06	243.65	0.3519	2,802
2003	29,551.12	3.13	924.95	0.2660	7,861
2004	11,663.54	3.15	367.40	0.2362	2,755
2006	9,236.84	3.20	295.58	0.1760	1,626
2007	15,499.19	3.23	500.62	0.1454	2,254
2008	20,159.43	3.25	655.18	0.1138	2,294
2009	3,796.60	3.29	124.91	0.0822	312
	173,365.48		5,301.72		57,897
CARMACKS					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	1,753.43	2.22	38.93	0.8991	1,577
1999	4,228.29	3.04	128.54	0.3800	1,607
2000	22,636.55	3.06	692.68	0.3519	7,966
2001	72,540.11	3.09	2,241.49	0.3244	23,532
	101,158.38		3,101.64		34,682
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. 0					
1971	3,489.80	2.22	77.47	0.8991	3,138
1972	392.81	2.26	8.88	0.8927	351
1976	2,134.00	2.41	51.43	0.8556	1,826
1980	2,677.41	2.57	68.81	0.8096	2,168
1985	1,408.73	2.83	39.87	0.7500	1,057

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. 0					
1990	70,054.07	3.17	2,220.71	0.6816	47,749
1991	4,985.00	3.26	162.51	0.6683	3,331
1993	33,561.73	3.45	1,157.88	0.6382	21,419
1994	1,818.80	3.55	64.57	0.6212	1,130
1998	7,421.15	4.07	302.04	0.5494	4,077
1999	14,916.17	4.22	629.46	0.5275	7,868
2000	15,290.59	4.39	671.26	0.5048	7,719
2001	16,054.87	4.58	735.31	0.4809	7,721
2003	28,717.40	5.01	1,438.74	0.4258	12,228
2004	4,956.93	5.26	260.73	0.3945	1,956
2006	9,043.55	5.84	528.14	0.3212	2,905
2007	4,788.51	6.19	296.41	0.2786	1,334
2008	62,915.66	6.58	4,139.85	0.2303	14,489
	284,627.18		12,854.07		142,466
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	14,437.93	2.22	320.52	0.8991	12,981
1972	16,367.43	2.25	368.27	0.8888	14,547
2001	43,957.09	3.09	1,358.27	0.3244	14,260
2002	18,022.71	3.11	560.51	0.2954	5,324
2006	2,166.70	3.20	69.33	0.1760	381
	94,951.86		2,676.90		47,493
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1981	3,895.02	2.55	99.32	0.7778	3,030
1982	17,114.85	2.59	443.27	0.7640	13,076
1986	23,198.32	2.70	626.35	0.6885	15,972
1989	22,032.00	2.79	614.69	0.6278	13,832
1990	6,856.39	2.82	193.35	0.6063	4,157

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1998	34,163.99	3.02	1,031.75	0.4077	13,929
1999	2,398.51	3.04	72.91	0.3800	911
2000	9,706.06	3.06	297.01	0.3519	3,416
	119,365.14		3,378.65		68,323
PELLY CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2033					
NET SALVAGE PERCENT.. 0					
1989	35,003.00	2.82	987.08	0.6345	22,209
1990	6,856.39	2.86	196.09	0.6149	4,216
1991	4,985.00	2.89	144.07	0.5924	2,953
1993	11,042.37	2.98	329.06	0.5513	6,088
1994	1,392.96	3.03	42.21	0.5302	739
1997	206,593.21	3.19	6,590.32	0.4626	95,570
1998	3,965.69	3.25	128.88	0.4388	1,740
1999	5,250.25	3.32	174.31	0.4150	2,179
2000	110.64	3.39	3.75	0.3898	43
2003	13,614.56	3.65	496.93	0.3102	4,223
2004	12,290.60	3.75	460.90	0.2812	3,456
2006	8,425.63	3.98	335.34	0.2189	1,844
2007	18,831.92	4.11	773.99	0.1850	3,484
2008	103,372.31	4.25	4,393.32	0.1488	15,382
	431,734.53		15,056.25		164,126
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	1,502.01	2.22	33.34	0.8991	1,350
1973	2,302.74	2.29	52.73	0.8816	2,030
1989	375.00	2.79	10.46	0.6278	235
1990	6,856.39	2.82	193.35	0.6063	4,157
1998	4,769.62	3.02	144.04	0.4077	1,945

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1999	20,795.02	3.04	632.17	0.3800	7,902
2000	87,363.46	3.06	2,673.32	0.3519	30,743
2004	907.50	3.15	28.59	0.2362	214
	124,871.74		3,768.00		48,576
STEWART CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	1,063.94	2.22	23.62	0.8991	957
1982	7,537.07	2.59	195.21	0.7640	5,758
1998	11,389.20	3.02	343.95	0.4077	4,643
1999	6,183.82	3.04	187.99	0.3800	2,350
2000	14,867.21	3.06	454.94	0.3519	5,232
2003	24,500.84	3.13	766.88	0.2660	6,517
2004	4,882.85	3.15	153.81	0.2362	1,153
	70,424.93		2,126.40		26,610
SWIFT RIVER					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1986	100.02	2.70	2.70	0.6885	69
1991	4,985.00	2.84	141.57	0.5822	2,902
1998	43,772.61	3.02	1,321.93	0.4077	17,846
1999	869.59	3.04	26.44	0.3800	330
2000	110.61	3.06	3.38	0.3519	39
2003	33,457.39	3.13	1,047.22	0.2660	8,900
2004	1,582.78	3.15	49.86	0.2362	374
2009	4,969.67	3.29	163.50	0.0822	409
2010	3,712.47	3.33	123.63	0.0500	186
	93,560.14		2,880.23		31,055

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
TESLIN					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1976	544.02	2.39	13.00	0.8484	462
1981	487.94	2.55	12.44	0.7778	380
1982	2,068.56	2.59	53.58	0.7640	1,580
1993	26,881.19	2.90	779.55	0.5365	14,422
1999	4,228.29	3.04	128.54	0.3800	1,607
2001	20,206.63	3.09	624.38	0.3244	6,555
	54,416.63		1,611.49		25,006
WATSON LAKE					
INTERIM SURVIVOR CURVE.. IOWA 35-R3					
PROBABLE RETIREMENT YEAR.. 12-2113					
NET SALVAGE PERCENT.. 0					
1971	40,922.41	2.22	908.48	0.8991	36,793
1973	12,675.52	2.29	290.27	0.8816	11,175
1974	5,654.23	2.32	131.18	0.8700	4,919
1976	782.05	2.39	18.69	0.8484	663
1984	9,095.34	2.65	241.03	0.7288	6,629
1987	220,208.40	2.73	6,011.69	0.6688	147,275
1989	42,648.64	2.79	1,189.90	0.6278	26,775
1990	31,215.94	2.82	880.29	0.6063	18,926
1994	6,000.88	2.92	175.23	0.5110	3,066
1997	13,284.17	2.99	397.20	0.4336	5,760
1998	3,968.07	3.02	119.84	0.4077	1,618
1999	77,281.64	3.04	2,349.36	0.3800	29,367
2000	1,866.83	3.06	57.12	0.3519	657
2002	12,712.92	3.11	395.37	0.2954	3,755
2004	2,043.14	3.15	64.36	0.2362	483
2005	4,960.69	3.17	157.25	0.2060	1,022
2007	30,679.14	3.21	984.80	0.1444	4,430
2008	9,332.25	3.23	301.43	0.1130	1,055
2011	52,856.96	3.36	1,775.99	0.0168	888
	578,189.22		16,449.48		305,256
MOBILES					
SURVIVOR CURVE.. IOWA 35-R3					
NET SALVAGE PERCENT.. 0					
1971	10,783.16	2.22	239.39	0.8991	9,695
1986	5,350.99	2.70	144.48	0.6885	3,684

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 446.00 - ACCESSORY ELECTRIC EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
MOBILES					
SURVIVOR CURVE.. IOWA 35-R3					
NET SALVAGE PERCENT.. 0					
1993	17,452.58	2.90	506.12	0.5365	9,363
2000	18,845.94	3.06	576.69	0.3519	6,632
2001	35,219.37	3.09	1,088.28	0.3244	11,425
	87,652.04		2,554.96		40,799
	2,214,317.27		71,759.79		992,289

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.24

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
BEAVER CREEK					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	184.59	2.09	3.86	0.8464	156
1982	694.02	2.36	16.38	0.6962	483
1991	2,135.57	2.55	54.46	0.5228	1,116
2003	8,443.18	2.78	234.72	0.2363	1,995
2004	3,332.42	2.80	93.31	0.2100	700
2007	22,115.51	2.89	639.14	0.1300	2,875
2009	11,697.35	2.96	346.24	0.0740	866
	48,602.64		1,388.11		8,191
CARMACKS					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	26.10	2.09	0.55	0.8464	22
1982	430.77	2.36	10.17	0.6962	300
2010	3,578.86	3.01	107.72	0.0452	162
2011	3,330.38	3.09	102.91	0.0154	51
	7,366.11		221.35		535
DESTRUCTION BAY					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2023					
NET SALVAGE PERCENT.. 0					
1979	1,551.73	2.42	37.55	0.7865	1,220
1982	1,587.73	2.56	40.65	0.7552	1,199
1991	7,781.34	3.19	248.22	0.6540	5,089
1993	198.09	3.38	6.70	0.6253	124
2003	8,204.98	4.97	407.79	0.4224	3,466
2004	1,416.28	5.22	73.93	0.3915	554
2007	2,392.19	6.15	147.12	0.2768	662
2009	4,915.64	7.00	344.09	0.1750	860
	28,047.98		1,306.05		13,174

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
HAINES JUNCTION					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	1,283.32	2.09	26.82	0.8464	1,086
1982	430.77	2.36	10.17	0.6962	300
2007	740.06	2.89	21.39	0.1300	96
	2,454.15		58.38		1,482
OLD CROW					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	334.88	2.09	7.00	0.8464	283
1982	430.77	2.36	10.17	0.6962	300
1991	845.54	2.55	21.56	0.5228	442
1992	89,611.14	2.57	2,303.01	0.5012	44,913
1996	76.70	2.64	2.02	0.4092	31
1998	25,966.14	2.68	695.89	0.3618	9,395
2004	51,464.79	2.80	1,441.01	0.2100	10,808
2007	2,765.55	2.89	79.92	0.1300	360
	171,495.51		4,560.58		66,532
PELLY CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2033					
NET SALVAGE PERCENT.. 0					
1971	63.84	2.09	1.33	0.8464	54
1982	2,232.98	2.38	53.14	0.7021	1,568
1991	23,272.01	2.70	628.34	0.5535	12,881
1992	1,386.99	2.74	38.00	0.5343	741
2003	3,889.87	3.53	137.31	0.3000	1,167
2004	3,511.59	3.63	127.47	0.2722	956
2007	7,139.56	4.01	286.30	0.1804	1,288
2009	11,771.71	4.32	508.54	0.1080	1,271
2011	8,216.80	4.74	389.48	0.0237	195
	61,485.35		2,169.91		20,121

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
ROSS RIVER					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	388.01	2.09	8.11	0.8464	328
1982	430.77	2.36	10.17	0.6962	300
2007	8,820.43	2.89	254.91	0.1300	1,147
	9,639.21		273.19		1,775
STEWART CROSSING					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1971	136.08	2.09	2.84	0.8464	115
1982	2,482.06	2.36	58.58	0.6962	1,728
1992	1,243.54	2.57	31.96	0.5012	623
2003	7,000.23	2.78	194.61	0.2363	1,654
2004	1,395.10	2.80	39.06	0.2100	293
2009	24,862.34	2.96	735.93	0.0740	1,840
2011	47,562.55	3.09	1,469.68	0.0154	732
	84,681.90		2,532.66		6,985
SWIFT RIVER					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1982	430.31	2.36	10.16	0.6962	300
1998	1,482.16	2.68	39.72	0.3618	536
2003	9,559.27	2.78	265.75	0.2363	2,259
2004	452.22	2.80	12.66	0.2100	95
	11,923.96		328.29		3,190

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 447.00 - MISCELLANEOUS POWER PLANT EQUIPMENT - DIESEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
TESLIN					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2053					
NET SALVAGE PERCENT.. 0					
1982	430.77	2.36	10.17	0.6962	300
2007	69,113.54	2.89	1,997.38	0.1300	8,985
2009	233.79	2.96	6.92	0.0740	17
	69,778.10		2,014.47		9,302
WATSON LAKE					
INTERIM SURVIVOR CURVE.. IOWA 40-R3					
PROBABLE RETIREMENT YEAR.. 12-2113					
NET SALVAGE PERCENT.. 0					
1971	963.89	2.09	20.15	0.8464	816
1979	2,627.48	2.29	60.17	0.7442	1,955
1982	12,722.46	2.36	300.25	0.6962	8,857
1987	14,434.04	2.47	356.52	0.6052	8,735
1997	54,613.60	2.66	1,452.72	0.3857	21,064
1999	8,046.80	2.69	216.46	0.3362	2,705
2000	1,450.00	2.71	39.30	0.3116	452
2007	112,714.67	2.82	3,178.55	0.1269	14,303
2008	26,941.49	2.84	765.14	0.0994	2,678
2011	23,915.13	2.95	705.50	0.0148	354
	258,429.56		7,094.76		61,919
MOBILES					
SURVIVOR CURVE.. IOWA 40-R3					
NET SALVAGE PERCENT.. 0					
2005	18,356.25	2.79	512.14	0.1814	3,330
2006	27,067.90	2.80	757.90	0.1540	4,168
2007	32,689.60	2.82	921.85	0.1269	4,148
2010	5,364.03	2.89	155.02	0.0434	233
2011	8,691.73	2.95	256.41	0.0148	129
	92,169.51		2,603.32		12,008
	846,073.98		24,551.07		205,214

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.90

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 457.00 - SUBSTATION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 50-R4					
NET SALVAGE PERCENT.. -10					
1957	8,481.84	1.67	155.81	0.9102	8,492
1960	3,229.85	1.73	61.46	0.8910	3,166
1961	657.80	1.75	12.66	0.8838	640
1963	1,015.95	1.78	19.89	0.8633	965
1964	213.85	1.80	4.23	0.8550	201
1965	410.15	1.82	8.21	0.8463	382
1966	62.60	1.83	1.26	0.8326	57
1967	5,878.36	1.85	119.62	0.8232	5,323
1968	14,018.01	1.86	286.81	0.8091	12,476
1969	25,261.00	1.87	519.62	0.7948	22,085
1970	17,772.00	1.89	369.48	0.7844	15,334
1971	3,930.00	1.90	82.14	0.7695	3,327
1974	41,250.75	1.94	880.29	0.7275	33,011
1975	143,608.80	1.95	3,080.41	0.7118	112,443
1981	8,150.00	2.01	180.20	0.6130	5,496
1982	3,210.00	2.02	71.33	0.5959	2,104
1984	9,590.00	2.04	215.20	0.5610	5,918
1985	14,603.26	2.05	329.30	0.5432	8,726
1986	43,015.79	2.06	974.74	0.5253	24,856
1988	21,596.39	2.07	491.75	0.4864	11,555
1989	18,476.14	2.07	420.70	0.4658	9,467
1992	231,307.73	2.09	5,317.76	0.4076	103,709
1993	460,428.37	2.09	10,585.25	0.3866	195,802
1996	147,978.24	2.10	3,418.30	0.3255	52,984
1997	94,152.91	2.11	2,185.29	0.3060	31,692
1999	62,040.09	2.11	1,439.95	0.2638	18,003
2000	4,081.39	2.11	94.73	0.2426	1,089
	1,384,421.27		31,326.39		689,303

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.26

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 471.00 - LAND RIGHTS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 75-R3					
NET SALVAGE PERCENT.. 0					
1971	1,500.00	1.35	20.25	0.5468	820
1979	198.05	1.39	2.75	0.4518	89
1994	12,700.80	1.46	185.43	0.2555	3,245
1995	44,975.18	1.47	661.14	0.2426	10,911
1996	46,085.52	1.47	677.46	0.2278	10,498
1997	140,113.75	1.48	2,073.68	0.2146	30,068
1998	50,522.14	1.48	747.73	0.1998	10,094
1999	50,004.19	1.49	745.06	0.1862	9,311
2000	49,670.66	1.49	740.09	0.1714	8,514
2001	55,348.17	1.49	824.69	0.1564	8,656
2002	34,647.85	1.50	519.72	0.1425	4,937
2003	61,972.64	1.50	929.59	0.1275	7,902
2004	60,926.26	1.51	919.99	0.1132	6,897
2005	204,085.51	1.51	3,081.69	0.0982	20,041
2006	46,254.29	1.52	703.07	0.0836	3,867
2007	69,728.37	1.53	1,066.84	0.0688	4,797
2008	103,657.56	1.53	1,585.96	0.0536	5,556
2009	72,924.99	1.54	1,123.04	0.0385	2,808
2010	86,743.57	1.56	1,353.20	0.0234	2,030
2011	75,548.93	1.58	1,193.67	0.0079	597
	1,267,608.43		19,155.05		151,638

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.51

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 473.00 - POLES, TOWERS AND FIXTURES - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -75					
1958	3,014.82	1.70	89.69	0.9095	4,798
1959	3,422.64	1.72	103.02	0.9030	5,409
1960	64,066.35	1.74	1,950.82	0.8961	100,467
1961	22,262.77	1.76	685.69	0.8888	34,628
1962	17,904.69	1.78	557.73	0.8811	27,608
1963	22,736.58	1.80	716.20	0.8730	34,736
1964	25,528.25	1.82	813.07	0.8645	38,621
1965	24,225.28	1.84	780.05	0.8556	36,273
1966	70,219.67	1.86	2,285.65	0.8463	103,997
1967	36,246.48	1.88	1,192.51	0.8366	53,067
1968	96,667.60	1.90	3,214.20	0.8265	139,818
1969	106,747.78	1.92	3,586.73	0.8160	152,436
1970	16,023.49	1.94	544.00	0.8051	22,576
1971	18,709.16	1.96	641.72	0.7938	25,990
1972	129,825.22	1.98	4,498.44	0.7821	177,689
1973	98,707.41	2.00	3,454.76	0.7700	133,008
1974	89,544.20	2.02	3,165.39	0.7575	118,702
1975	146,445.21	2.04	5,228.09	0.7446	190,825
1976	96,229.81	2.06	3,469.08	0.7313	123,153
1977	240,706.63	2.07	8,719.60	0.7142	300,847
1978	212,027.14	2.09	7,754.89	0.7002	259,807
1979	200,296.24	2.11	7,395.94	0.6858	240,386
1980	108,769.20	2.13	4,054.37	0.6710	127,722
1981	129,163.87	2.14	4,837.19	0.6527	147,534
1982	354,099.48	2.16	13,384.96	0.6372	394,856
1983	135,039.76	2.18	5,151.77	0.6213	146,825
1984	273,619.23	2.19	10,486.46	0.6022	288,354
1985	754,437.87	2.21	29,177.88	0.5856	773,148
1986	279,561.30	2.22	10,860.96	0.5661	276,954
1987	417,946.08	2.24	16,383.49	0.5488	401,395
1988	333,623.95	2.26	13,194.83	0.5311	310,078
1989	575,010.94	2.27	22,842.31	0.5108	514,002
1990	1,110,346.89	2.29	44,497.15	0.4924	956,786
1991	782,222.41	2.30	31,484.45	0.4715	645,431
1992	1,164,266.14	2.32	47,269.21	0.4524	921,750
1993	1,574,269.86	2.33	64,190.85	0.4310	1,187,393
1994	1,005,504.27	2.35	41,351.36	0.4112	723,561
1995	900,750.05	2.36	37,200.98	0.3894	613,816
1996	899,513.01	2.37	37,307.30	0.3674	578,342
1997	770,189.70	2.39	32,213.18	0.3466	467,159
1998	679,543.24	2.40	28,540.82	0.3240	385,301
1999	766,596.42	2.41	32,331.20	0.3012	404,073
2000	612,683.04	2.43	26,054.35	0.2794	299,571
2001	636,466.49	2.44	27,177.12	0.2562	285,360
2002	985,772.90	2.45	42,265.01	0.2328	401,604

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 473.00 - POLES, TOWERS AND FIXTURES - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -75					
2003	775,635.83	2.46	33,391.12	0.2091	283,825
2004	1,281,162.37	2.48	55,602.45	0.1860	417,018
2005	989,206.22	2.49	43,104.66	0.1618	280,094
2006	1,401,831.25	2.50	61,330.12	0.1375	337,316
2007	1,091,993.21	2.52	48,156.90	0.1134	216,706
2008	1,616,156.35	2.53	71,555.32	0.0886	250,585
2009	1,327,095.60	2.55	59,221.64	0.0638	148,170
2010	1,874,751.64	2.57	84,316.96	0.0386	126,639
2011	2,882,760.32	2.62	132,174.56	0.0131	66,087
	30,231,546.31		1,271,958.20		15,702,296

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.21

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.00 - OVERHEAD CONDUCTOR - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R4					
NET SALVAGE PERCENT.. -80					
1948	148.71	1.55	4.15	0.9842	263
1949	510.02	1.57	14.41	0.9812	901
1950	123.73	1.59	3.54	0.9778	218
1951	739.89	1.61	21.44	0.9740	1,297
1952	1,127.00	1.63	33.07	0.9698	1,967
1953	2,029.00	1.65	60.26	0.9652	3,525
1954	2,638.00	1.67	79.30	0.9602	4,559
1955	418.31	1.69	12.72	0.9548	719
1956	2,743.00	1.71	84.43	0.9490	4,686
1957	922.06	1.73	28.71	0.9428	1,565
1958	5,559.00	1.76	176.11	0.9416	9,422
1959	8,040.00	1.78	257.60	0.9345	13,524
1960	72,384.01	1.80	2,345.24	0.9270	120,780
1961	9,293.00	1.83	306.11	0.9242	15,459
1962	12,100.41	1.85	402.94	0.9158	19,947
1963	14,243.14	1.87	479.42	0.9070	23,253
1964	10,540.74	1.90	360.49	0.9025	17,123
1965	14,565.83	1.92	503.40	0.8928	23,408
1966	43,767.33	1.94	1,528.36	0.8827	69,540
1967	35,893.76	1.96	1,266.33	0.8722	56,352
1968	68,248.09	1.98	2,432.36	0.8613	105,808
1969	125,172.05	2.00	4,506.19	0.8500	191,513
1970	27,008.59	2.02	982.03	0.8383	40,754
1971	18,964.86	2.04	696.39	0.8262	28,204
1972	109,788.05	2.06	4,070.94	0.8137	160,802
1973	108,551.49	2.08	4,064.17	0.8008	156,470
1974	57,051.46	2.09	2,146.28	0.7838	80,490
1975	144,638.16	2.11	5,493.36	0.7702	200,521
1976	106,854.96	2.13	4,096.82	0.7562	145,447
1977	145,040.78	2.14	5,586.97	0.7383	192,750
1978	93,920.92	2.16	3,651.65	0.7236	122,330
1979	77,160.47	2.17	3,013.89	0.7052	97,944
1980	122,191.66	2.19	4,816.80	0.6898	151,718
1981	87,840.47	2.20	3,478.48	0.6710	106,094
1982	209,885.33	2.21	8,349.24	0.6520	246,321
1983	132,046.38	2.23	5,300.34	0.6356	151,072
1984	121,892.29	2.24	4,914.70	0.6160	135,154
1985	677,899.61	2.25	27,454.93	0.5962	727,495
1986	136,683.35	2.26	5,560.28	0.5763	141,787
1987	328,625.90	2.27	13,427.65	0.5562	329,007
1988	239,184.34	2.28	9,816.13	0.5358	230,679
1989	332,701.42	2.29	13,713.95	0.5152	308,534
1990	680,637.85	2.30	28,178.41	0.4945	605,836
1991	519,771.93	2.30	21,518.56	0.4715	441,130
1992	486,666.63	2.31	20,235.60	0.4504	394,550

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.00 - OVERHEAD CONDUCTOR - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R4					
NET SALVAGE PERCENT.. -80					
1993	792,959.72	2.32	33,114.00	0.4292	612,609
1994	463,654.51	2.32	19,362.21	0.4060	338,839
1995	357,845.36	2.33	15,008.03	0.3844	247,600
1996	560,475.87	2.33	23,506.36	0.3612	364,399
1997	521,699.29	2.34	21,973.97	0.3393	318,623
1998	410,383.42	2.34	17,285.35	0.3159	233,352
1999	410,977.25	2.34	17,310.36	0.2925	216,380
2000	479,332.56	2.35	20,275.77	0.2702	233,128
2001	472,747.67	2.35	19,997.23	0.2468	210,013
2002	511,085.75	2.35	21,618.93	0.2232	205,334
2003	423,598.69	2.35	17,918.22	0.1998	152,343
2004	778,010.48	2.35	32,909.84	0.1762	246,754
2005	793,470.21	2.36	33,706.61	0.1534	219,093
2006	1,160,619.99	2.36	49,303.14	0.1298	271,167
2007	1,581,317.34	2.36	67,174.36	0.1062	302,285
2008	1,517,742.62	2.36	64,473.71	0.0826	225,658
2009	942,790.65	2.36	40,049.75	0.0590	100,124
2010	1,356,461.25	2.36	57,622.47	0.0354	86,434
2011	1,583,225.80	2.37	67,540.41	0.0118	33,628
	20,514,612.41		855,624.87		10,498,681

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 4.17

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.10 - OVERHEAD SERVICES - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
1945	2,203.16	1.45	35.14	0.9642	2,337
1946	414.58	1.47	6.70	0.9628	439
1947	476.35	1.49	7.81	0.9610	504
1948	569.49	1.50	9.40	0.9525	597
1949	673.48	1.52	11.26	0.9500	704
1950	808.02	1.54	13.69	0.9471	842
1951	900.65	1.56	15.46	0.9438	935
1952	1,366.00	1.58	23.74	0.9401	1,413
1953	2,459.00	1.60	43.28	0.9360	2,532
1954	3,197.00	1.61	56.62	0.9258	3,256
1955	2,771.00	1.63	49.68	0.9210	2,807
1956	3,325.00	1.65	60.35	0.9158	3,350
1957	3,592.00	1.67	65.99	0.9102	3,596
1958	1,170.00	1.70	21.88	0.9095	1,171
1959	1,533.00	1.72	29.00	0.9030	1,523
1960	1,560.00	1.74	29.86	0.8961	1,538
1961	1,791.78	1.76	34.69	0.8888	1,752
1962	5,328.00	1.78	104.32	0.8811	5,164
1963	2,524.00	1.80	49.98	0.8730	2,424
1964	4,560.00	1.82	91.29	0.8645	4,336
1965	3,229.00	1.84	65.35	0.8556	3,039
1966	4,597.36	1.86	94.06	0.8463	4,280
1967	7,481.00	1.88	154.71	0.8366	6,884
1968	8,000.00	1.90	167.20	0.8265	7,273
1969	7,521.50	1.92	158.85	0.8160	6,751
1970	11,754.13	1.94	250.83	0.8051	10,410
1971	12,073.93	1.96	260.31	0.7938	10,543
1972	12,957.01	1.98	282.20	0.7821	11,147
1973	14,692.86	2.00	323.24	0.7700	12,445
1974	20,167.00	2.02	448.11	0.7575	16,804
1975	34,619.23	2.04	776.86	0.7446	28,355
1976	37,678.27	2.06	853.79	0.7313	30,310
1977	42,422.26	2.07	965.95	0.7142	33,328
1978	62,182.03	2.09	1,429.56	0.7002	47,894
1979	52,049.79	2.11	1,208.08	0.6858	39,265
1980	43,273.51	2.13	1,013.90	0.6710	31,940
1981	53,231.36	2.14	1,253.07	0.6527	38,219
1982	30,980.05	2.16	736.09	0.6372	21,715
1983	40,503.38	2.18	971.27	0.6213	27,681
1984	40,236.69	2.19	969.30	0.6022	26,654
1985	32,685.06	2.21	794.57	0.5856	21,054
1986	51,608.88	2.22	1,260.29	0.5661	32,137
1987	67,879.82	2.24	1,672.56	0.5488	40,978
1988	66,613.00	2.26	1,656.00	0.5311	38,916
1989	81,267.48	2.27	2,029.25	0.5108	45,663

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 474.10 - OVERHEAD SERVICES - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
1990	89,672.48	2.29	2,258.85	0.4924	48,570
1991	108,151.36	2.30	2,736.23	0.4715	56,093
1992	163,702.21	2.32	4,177.68	0.4524	81,465
1993	112,072.14	2.33	2,872.41	0.4310	53,133
1994	64,781.32	2.35	1,674.60	0.4112	29,302
1995	55,117.61	2.36	1,430.85	0.3894	23,609
1997	45,912.56	2.39	1,207.04	0.3466	17,505
1998	46,874.69	2.40	1,237.49	0.3240	16,706
1999	40,693.10	2.41	1,078.77	0.3012	13,482
2000	33,672.14	2.43	900.06	0.2794	10,349
2001	25,583.05	2.44	686.65	0.2562	7,210
2002	59,316.63	2.45	1,598.58	0.2328	15,190
2003	55,673.16	2.46	1,506.52	0.2091	12,805
2004	68,225.83	2.48	1,861.20	0.1860	13,959
2005	63,429.49	2.49	1,737.33	0.1618	11,289
2006	136,065.53	2.50	3,741.80	0.1375	20,580
2007	191,840.99	2.52	5,317.83	0.1134	23,930
2008	225,262.76	2.53	6,269.06	0.0886	21,954
2009	129,908.59	2.55	3,643.94	0.0638	9,117
2010	31,334.64	2.57	885.83	0.0386	1,330
2011	221,235.12	2.62	6,376.00	0.0131	3,188
	2,849,452.51		73,754.26		1,125,671

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.59

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.00 - UNDERGROUND CONDUIT - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -50					
1961	12.02	1.76	0.32	0.8888	16
1969	1,356.35	1.92	39.06	0.8160	1,660
1971	65.00	1.96	1.91	0.7938	77
1972	14,154.38	1.98	420.39	0.7821	16,605
1973	5,056.00	2.00	151.68	0.7700	5,840
1974	7,373.22	2.02	223.41	0.7575	8,378
1975	8,587.37	2.04	262.77	0.7446	9,591
1976	66,670.57	2.06	2,060.12	0.7313	73,134
1977	4,549.00	2.07	141.25	0.7142	4,873
1978	257,255.88	2.09	8,064.97	0.7002	270,196
1979	17,007.99	2.11	538.30	0.6858	17,496
1980	716,055.98	2.13	22,877.99	0.6710	720,710
1981	23,266.00	2.14	746.84	0.6527	22,779
1982	49,311.39	2.16	1,597.69	0.6372	47,132
1983	68,295.31	2.18	2,233.26	0.6213	63,648
1984	32,676.52	2.19	1,073.42	0.6022	29,517
1985	61,229.70	2.21	2,029.76	0.5856	53,784
1986	21,965.42	2.22	731.45	0.5661	18,652
1987	181,124.12	2.24	6,085.77	0.5488	149,101
1988	70,261.38	2.26	2,381.86	0.5311	55,974
1989	1,382,612.06	2.27	47,077.94	0.5108	1,059,357
1990	239,241.64	2.29	8,217.95	0.4924	176,704
1991	171,937.17	2.30	5,931.83	0.4715	121,603
1992	736,477.56	2.32	25,629.42	0.4524	499,774
1993	996,540.23	2.33	34,829.08	0.4310	644,263
1994	267,822.74	2.35	9,440.75	0.4112	165,193
1995	1,124,713.96	2.36	39,814.87	0.3894	656,945
1996	533,259.01	2.37	18,957.36	0.3674	293,879
1997	1,120,397.24	2.39	40,166.24	0.3466	582,495
1998	658,133.08	2.40	23,692.79	0.3240	319,853
1999	875,078.79	2.41	31,634.10	0.3012	395,361
2000	527,543.67	2.43	19,228.97	0.2794	221,094
2001	1,723,813.98	2.44	63,091.59	0.2562	662,462
2002	1,013,816.38	2.45	37,257.75	0.2328	354,025
2003	1,153,334.82	2.46	42,558.05	0.2091	361,743
2004	997,611.57	2.48	37,111.15	0.1860	278,334
2005	724,497.68	2.49	27,059.99	0.1618	175,836
2006	740,562.48	2.50	27,771.09	0.1375	152,741
2007	826,505.65	2.52	31,241.91	0.1134	140,589
2008	823,804.14	2.53	31,263.37	0.0886	109,484

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.00 - UNDERGROUND CONDUIT - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -50					
2009	1,222,366.98	2.55	46,755.54	0.0638	116,981
2010	627,766.58	2.57	24,200.40	0.0386	36,348
2011	888,477.52	2.62	34,917.17	0.0131	17,459
	20,982,588.53		759,511.53		9,111,686

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.62

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 475.10 - UNDERGROUND SERVICES - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 40-R4					
NET SALVAGE PERCENT.. -10					
1978	8,805.65	2.35	227.63	0.7872	7,625
1979	16,155.81	2.37	421.18	0.7702	13,688
1980	5,116.57	2.39	134.51	0.7528	4,237
1981	14,328.30	2.41	379.84	0.7350	11,584
1982	6,135.87	2.43	164.01	0.7168	4,838
1983	4,112.25	2.45	110.83	0.6982	3,158
1984	6,049.74	2.47	164.37	0.6792	4,520
1985	2,467.31	2.49	67.58	0.6598	1,791
1986	47,595.84	2.50	1,308.89	0.6375	33,377
1987	64,385.16	2.52	1,784.76	0.6174	43,727
1988	55,348.04	2.53	1,540.34	0.5946	36,201
1989	64,252.19	2.54	1,795.21	0.5715	40,392
1990	63,917.48	2.56	1,799.92	0.5504	38,698
1991	85,692.58	2.57	2,422.53	0.5268	49,657
1992	151,300.89	2.58	4,293.92	0.5031	83,731
1993	198,187.47	2.59	5,646.36	0.4792	104,469
1994	84,909.93	2.60	2,428.42	0.4550	42,497
1995	123,873.01	2.61	3,556.39	0.4306	58,674
1996	226,325.88	2.61	6,497.82	0.4046	100,729
1997	125,671.06	2.62	3,621.84	0.3799	52,517
1998	99,659.29	2.62	2,872.18	0.3537	38,774
1999	72,633.75	2.63	2,101.29	0.3288	26,270
2000	15,457.57	2.63	447.19	0.3024	5,142
2001	64,800.69	2.64	1,881.81	0.2772	19,759
2002	71,681.66	2.64	2,081.64	0.2508	19,776
2003	75,033.52	2.64	2,178.97	0.2244	18,521
2004	206,861.36	2.65	6,030.01	0.1988	45,236
2005	148,375.29	2.65	4,325.14	0.1722	28,105
2006	233,234.91	2.65	6,798.80	0.1458	37,406
2007	163,236.52	2.65	4,758.34	0.1192	21,404
2008	95,096.67	2.65	2,772.07	0.0928	9,707
2009	39,357.36	2.66	1,151.60	0.0665	2,879
2010	94,836.76	2.66	2,774.92	0.0399	4,162
2011	218,180.81	2.66	6,383.97	0.0133	3,192
	2,953,077.19		84,924.28		1,016,443

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.88

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.10 - METERS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 15-L0					
NET SALVAGE PERCENT.. 0					
1970	18.15	2.25	0.41	0.9338	17
1971	4,291.77	2.30	98.71	0.9315	3,998
1972	4,159.27	2.34	97.33	0.9243	3,844
1973	4,922.20	2.39	117.64	0.9202	4,529
1974	1,065.68	2.44	26.00	0.9150	975
1975	10,392.34	2.49	258.77	0.9088	9,445
1976	3,532.46	2.55	90.08	0.9052	3,198
1977	2,160.36	2.61	56.39	0.9004	1,945
1978	3,961.72	2.66	105.38	0.8911	3,530
1979	468.92	2.73	12.80	0.8872	416
1980	4,344.54	2.79	121.21	0.8788	3,818
1981	3,588.21	2.86	102.62	0.8723	3,130
1982	5,232.71	2.93	153.32	0.8644	4,523
1983	562.52	3.00	16.88	0.8550	481
1984	2,268.84	3.08	69.88	0.8470	1,922
1985	4,581.74	3.16	144.78	0.8374	3,837
1986	4,570.19	3.25	148.53	0.8288	3,788
1987	8,609.54	3.34	287.56	0.8183	7,045
1988	11,962.73	3.44	411.52	0.8084	9,671
1989	35,899.48	3.54	1,270.84	0.7965	28,594
1990	12,441.33	3.65	454.11	0.7848	9,764
1991	11,062.14	3.76	415.94	0.7708	8,527
1992	35,072.97	3.88	1,360.83	0.7566	26,536
1993	62,568.13	4.01	2,508.98	0.7418	46,413
1994	6,205.20	4.15	257.52	0.7262	4,506
1995	9,796.96	4.30	421.27	0.7095	6,951
1996	8,617.32	4.46	384.33	0.6913	5,957
1997	20,081.35	4.64	931.77	0.6728	13,511
1998	95,664.33	4.82	4,611.02	0.6507	62,249
1999	71,622.77	5.03	3,602.63	0.6288	45,036
2000	110,805.59	5.26	5,828.37	0.6049	67,026
2001	38,275.23	5.51	2,108.97	0.5786	22,146
2002	38,701.01	5.79	2,240.79	0.5500	21,286
2003	109,974.70	6.10	6,708.46	0.5185	57,022
2004	120,520.80	6.46	7,785.64	0.4845	58,392
2005	15,995.63	6.87	1,098.90	0.4466	7,144
2006	8,685.31	7.36	639.24	0.4048	3,516
2007	39,317.09	7.94	3,121.78	0.3573	14,048
2008	18,765.20	8.66	1,625.07	0.3031	5,688

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.10 - METERS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 15-L0					
NET SALVAGE PERCENT.. 0					
2009	15,676.06	9.58	1,501.77	0.2395	3,754
2010	482,401.74	10.87	52,437.07	0.1630	78,631
2011	235,141.02	13.19	31,015.10	0.0660	15,519
	1,683,985.25		134,650.21		682,328

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 8.00

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 476.30 - AMR METERS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 15-R2.5					
NET SALVAGE PERCENT.. 0					
2007	7,789.88	7.26	565.55	0.3267	2,545
2008	29,425.21	7.45	2,192.18	0.2608	7,674
2009	11,869.27	7.67	910.37	0.1918	2,277
2010	12,710.93	7.94	1,009.25	0.1191	1,514
2011	5,851.04	8.50	497.34	0.0425	249
	67,646.33		5,174.69		14,259

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 7.65

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 477.10 - SUBSTATION EQUIPMENT - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 40-R4					
NET SALVAGE PERCENT.. -10					
1960	3,631.70	1.87	74.70	0.9630	3,847
1968	16,606.00	2.10	383.60	0.9135	16,687
1969	882.00	2.13	20.67	0.9052	878
1971	39,959.05	2.18	958.22	0.8829	38,808
1972	2,089.52	2.21	50.80	0.8730	2,007
1973	56,550.00	2.24	1,393.39	0.8624	53,646
1974	446.22	2.26	11.09	0.8475	416
1976	333,091.33	2.31	8,463.85	0.8200	300,448
1977	70,884.17	2.33	1,816.76	0.8038	62,674
1979	14,954.00	2.37	389.85	0.7702	12,669
1980	80,834.73	2.39	2,125.15	0.7528	66,938
1981	126,329.84	2.41	3,349.00	0.7350	102,138
1985	43,522.68	2.49	1,192.09	0.6598	31,588
1986	118,315.85	2.50	3,253.69	0.6375	82,969
1987	335,797.16	2.52	9,308.30	0.6174	228,053
1988	60,907.24	2.53	1,695.05	0.5946	39,837
1989	36,582.03	2.54	1,022.10	0.5715	22,997
1990	132,200.60	2.56	3,722.77	0.5504	80,040
1991	259,920.34	2.57	7,347.95	0.5268	150,619
1992	98,578.56	2.58	2,797.66	0.5031	54,554
1993	166,934.17	2.59	4,755.95	0.4792	87,994
1994	41,680.13	2.60	1,192.05	0.4550	20,861
1996	196,092.49	2.61	5,629.82	0.4046	87,273
1997	1,451.70	2.62	41.84	0.3799	607
1999	46,617.77	2.63	1,348.65	0.3288	16,861
2000	79,093.83	2.63	2,288.18	0.3024	26,310
2001	253,074.36	2.64	7,349.28	0.2772	77,167
2005	491,706.97	2.65	14,333.26	0.1722	93,139
2006	22,338.61	2.65	651.17	0.1458	3,583
	3,131,073.05		86,966.89		1,765,608

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.78

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.10 - STREET LIGHTS AND SIGNAL SYSTEMS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 30-R3					
NET SALVAGE PERCENT.. -10					
1974	4,057.78	2.46	109.80	0.9225	4,118
1975	230.46	2.51	6.36	0.9162	232
1977	42,389.29	2.60	1,212.33	0.8970	41,826
1978	22,260.89	2.64	646.46	0.8844	21,656
1979	15,471.24	2.69	457.79	0.8742	14,877
1980	184,650.87	2.74	5,565.38	0.8631	175,309
1981	28,488.46	2.79	874.31	0.8510	26,668
1982	69,549.87	2.83	2,165.09	0.8348	63,866
1983	113,988.36	2.88	3,611.15	0.8208	102,918
1984	98,481.92	2.92	3,163.24	0.8030	86,989
1985	29,194.06	2.96	950.56	0.7844	25,190
1986	348,615.98	3.01	11,542.68	0.7676	294,357
1987	137,151.99	3.05	4,601.45	0.7472	112,728
1988	209,962.68	3.09	7,136.63	0.7262	167,722
1989	572,762.96	3.13	19,720.23	0.7042	443,674
1990	271,383.70	3.17	9,463.15	0.6816	203,473
1991	222,337.62	3.21	7,850.74	0.6580	160,928
1992	89,796.68	3.25	3,210.23	0.6338	62,604
1993	353,801.93	3.28	12,765.17	0.6068	236,156
1994	247,288.34	3.32	9,030.97	0.5810	158,042
1995	310,528.34	3.36	11,477.13	0.5544	189,373
1996	107,223.57	3.39	3,998.37	0.5254	61,969
1997	413,878.23	3.42	15,570.10	0.4959	225,766
1998	217,759.97	3.46	8,287.94	0.4671	111,887
1999	251,341.73	3.49	9,649.01	0.4362	120,599
2000	210,200.54	3.52	8,138.96	0.4048	93,598
2001	356,557.44	3.55	13,923.57	0.3728	146,217
2002	195,535.23	3.58	7,700.18	0.3401	73,152
2003	588,194.07	3.61	23,357.19	0.3068	198,504
2004	504,727.00	3.64	20,209.27	0.2730	151,570
2005	109,056.61	3.67	4,402.62	0.2386	28,623
2006	799,992.38	3.70	32,559.69	0.2035	179,078
2007	524,616.74	3.73	21,525.02	0.1678	96,834
2008	217,945.03	3.76	9,014.21	0.1316	31,550
2009	584,538.96	3.79	24,369.43	0.0948	60,956
2010	196,401.93	3.83	8,274.41	0.0574	12,401
2011	497,158.76	3.91	21,382.80	0.0196	10,719
	9,147,521.61		347,923.62		4,196,129

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.80

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 478.20 - SENTINEL LIGHTS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 23-R2					
NET SALVAGE PERCENT.. 0					
1967	2,516.28			1.0000	2,516
1973	1,471.00	2.53	37.22	0.9740	1,433
1974	19,675.00	2.58	507.62	0.9675	19,036
1975	4,754.00	2.62	124.55	0.9563	4,546
1976	14,852.76	2.68	398.05	0.9514	14,131
1977	10,540.00	2.73	287.74	0.9418	9,927
1978	16,073.00	2.78	446.83	0.9313	14,969
1979	29,321.00	2.84	832.72	0.9230	27,063
1980	18,970.00	2.90	550.13	0.9135	17,329
1981	17,037.00	2.96	504.30	0.9028	15,381
1982	9,135.00	3.03	276.79	0.8938	8,165
1983	10,835.00	3.09	334.80	0.8806	9,541
1984	19,067.94	3.16	602.55	0.8690	16,570
1985	10,529.38	3.23	340.10	0.8560	9,013
1986	31,912.79	3.30	1,053.12	0.8415	26,855
1987	14,211.05	3.37	478.91	0.8256	11,733
1988	13,496.10	3.44	464.27	0.8084	10,910
1989	7,391.51	3.51	259.44	0.7898	5,838
1990	3,329.07	3.58	119.18	0.7697	2,562
1991	2,562.75	3.66	93.80	0.7503	1,923
1992	10,584.67	3.73	394.81	0.7274	7,699
1993	152.13	3.80	5.78	0.7030	107
1997	15,872.16	4.11	652.35	0.5960	9,460
1999	448.69	4.27	19.16	0.5338	240
	284,738.28		8,784.22		246,947

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.09

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 479.10 - LINE TRANSFORMERS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
1946	226.33	1.47	3.66	0.9628	240
1947	1,242.88	1.49	20.37	0.9610	1,314
1948	1,616.79	1.50	26.68	0.9525	1,694
1950	28.96	1.54	0.49	0.9471	30
1951	15,498.02	1.56	265.95	0.9438	16,090
1952	20,900.00	1.58	363.24	0.9401	21,613
1953	2,758.00	1.60	48.54	0.9360	2,840
1954	5,453.44	1.61	96.58	0.9258	5,554
1955	21,326.43	1.63	382.38	0.9210	21,606
1956	3,729.00	1.65	67.68	0.9158	3,757
1958	2,255.00	1.70	42.17	0.9095	2,256
1959	18,726.00	1.72	354.30	0.9030	18,601
1960	37,058.01	1.74	709.29	0.8961	36,528
1961	10,822.00	1.76	209.51	0.8888	10,580
1962	9,436.00	1.78	184.76	0.8811	9,145
1963	24,530.00	1.80	485.69	0.8730	23,556
1964	6,995.00	1.82	140.04	0.8645	6,652
1965	13,727.00	1.84	277.83	0.8556	12,919
1966	36,590.20	1.86	748.64	0.8463	34,063
1967	62,470.06	1.88	1,291.88	0.8366	57,489
1968	178,530.55	1.90	3,731.29	0.8265	162,311
1969	37,843.96	1.92	799.26	0.8160	33,969
1970	47,642.66	1.94	1,016.69	0.8051	42,193
1971	67,977.76	1.96	1,465.60	0.7938	59,357
1972	78,104.06	1.98	1,701.11	0.7821	67,194
1973	67,293.83	2.00	1,480.46	0.7700	56,998
1974	69,239.74	2.02	1,538.51	0.7575	57,694
1975	105,252.50	2.04	2,361.87	0.7446	86,208
1976	70,666.88	2.06	1,601.31	0.7313	56,847
1977	93,514.46	2.07	2,129.32	0.7142	73,467
1978	141,818.02	2.09	3,260.40	0.7002	109,231
1979	191,093.76	2.11	4,435.29	0.6858	144,157
1980	191,440.72	2.13	4,485.46	0.6710	141,302
1981	185,345.66	2.14	4,363.04	0.6527	133,073
1982	125,172.27	2.16	2,974.09	0.6372	87,736
1983	65,923.13	2.18	1,580.84	0.6213	45,054
1984	57,612.00	2.19	1,387.87	0.6022	38,163
1985	202,526.99	2.21	4,923.43	0.5856	130,460
1986	205,124.37	2.22	5,009.14	0.5661	127,733
1987	505,597.46	2.24	12,457.92	0.5488	305,219
1988	306,132.88	2.26	7,610.46	0.5311	178,846
1989	485,270.58	2.27	12,117.21	0.5108	272,664
1990	725,712.71	2.29	18,280.70	0.4924	393,075
1991	767,112.63	2.30	19,407.95	0.4715	397,863
1992	770,960.71	2.32	19,674.92	0.4524	383,661

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 479.10 - LINE TRANSFORMERS - DISTRIBUTION

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
1993	941,284.95	2.33	24,125.13	0.4310	446,263
1994	504,127.56	2.35	13,031.70	0.4112	228,027
1995	470,411.85	2.36	12,211.89	0.3894	201,496
1996	655,953.00	2.37	17,100.69	0.3674	265,097
1997	483,875.09	2.39	12,721.08	0.3466	184,482
1998	494,985.10	2.40	13,067.61	0.3240	176,413
1999	375,346.25	2.41	9,950.43	0.3012	124,360
2000	591,914.63	2.43	15,821.88	0.2794	181,919
2001	574,603.49	2.44	15,422.36	0.2562	161,935
2002	539,849.29	2.45	14,548.94	0.2328	138,245
2003	740,255.14	2.46	20,031.30	0.2091	170,266
2004	737,246.07	2.48	20,112.07	0.1860	150,841
2005	1,390,573.02	2.49	38,087.80	0.1618	247,494
2006	1,480,794.08	2.50	40,721.84	0.1375	223,970
2007	1,586,755.13	2.52	43,984.85	0.1134	197,932
2008	1,953,714.12	2.53	54,371.86	0.0886	190,409
2009	1,715,673.49	2.55	48,124.64	0.0638	120,406
2010	1,410,673.11	2.57	39,879.73	0.0386	59,897
2011	1,741,434.38	2.62	50,188.14	0.0131	25,094
	24,427,769.16		649,017.76		7,365,548

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.66

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 482.00 - STRUCTURES AND IMPROVEMENTS - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 40-L3					
NET SALVAGE PERCENT.. 0					
1972	59,482.48	2.00	1,189.65	0.7900	46,991
1973	16,635.00	2.04	339.35	0.7854	13,065
1974	46,735.00	2.08	972.09	0.7800	36,453
1976	1,500.00	2.16	32.40	0.7668	1,150
1977	1,015.00	2.19	22.23	0.7556	767
1979	14,807.00	2.27	336.12	0.7378	10,925
1981	12,462.00	2.35	292.86	0.7168	8,933
1982	21,706.00	2.39	518.77	0.7050	15,303
1984	24,285.00	2.46	597.41	0.6765	16,429
1986	2,778.08	2.53	70.29	0.6452	1,792
1987	379,195.74	2.55	9,669.49	0.6248	236,921
1988	87,857.59	2.58	2,266.73	0.6063	53,268
1989	3,500.00	2.61	91.35	0.5872	2,055
1990	45,253.00	2.63	1,190.15	0.5654	25,586
1991	1,424,433.43	2.65	37,747.49	0.5432	773,752
1992	300,985.15	2.67	8,036.30	0.5206	156,693
1993	117,588.04	2.69	3,163.12	0.4976	58,512
1994	58,849.20	2.71	1,594.81	0.4742	27,906
1995	33,602.05	2.72	913.98	0.4488	15,081
1996	25,776.27	2.74	706.27	0.4247	10,947
1997	55,730.18	2.75	1,532.58	0.3988	22,225
1998	83,574.87	2.77	2,315.02	0.3740	31,257
1999	9,019.44	2.78	250.74	0.3475	3,134
2000	50,931.86	2.79	1,421.00	0.3208	16,339
2001	47,503.75	2.80	1,330.10	0.2940	13,966
2002	25,441.90	2.81	714.92	0.2670	6,793
2003	46,885.37	2.82	1,322.17	0.2397	11,238
2004	48,669.62	2.82	1,372.48	0.2115	10,294
2005	3,289.66	2.82	92.77	0.1833	603
2006	83,642.46	2.83	2,367.08	0.1556	13,015
2007	12,536.74	2.83	354.79	0.1274	1,597
2008	76,031.98	2.83	2,151.71	0.0990	7,527
2009	74,558.63	2.83	2,110.01	0.0708	5,279
2010	98,128.40	2.83	2,777.03	0.0424	4,161
2011	64,924.42	2.83	1,837.36	0.0142	922
	3,459,315.31		91,700.62		1,660,879

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.65

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.00 - OFFICE FURNITURE AND EQUIPMENT - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1988	834.92			1.0000	835
1989	2,150.48			1.0000	2,150
1990	1,503.14			1.0000	1,503
1991	2,966.04			1.0000	2,966
1992	909.82			1.0000	910
1993	378.67			1.0000	379
1996	7,412.16			1.0000	7,412
1997	2,902.53	6.67	193.60	0.9667	2,806
1998	13,797.39	6.67	920.29	0.9000	12,418
1999	9,644.27	6.67	643.27	0.8333	8,037
2000	2,749.22	6.67	183.37	0.7667	2,108
2001	5,644.80	6.67	376.51	0.7000	3,951
2004	2,243.36	6.67	149.63	0.5000	1,122
2005	10,922.40	6.67	728.52	0.4333	4,733
2006	5,995.34	6.67	399.89	0.3667	2,198
2007	10,018.97	6.67	668.27	0.3000	3,006
2008	10,493.44	6.67	699.91	0.2333	2,448
2009	858.00	6.67	57.23	0.1667	143
2010	10,095.47	6.67	673.37	0.1000	1,010
2011	71,272.97	6.67	4,753.91	0.0333	2,376
	172,793.39		10,447.77		62,511

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.05

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 483.20 - COMPUTER EQUIPMENT AND ACCESSORIES - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. 5-SQUARE					
NET SALVAGE PERCENT.. 0					
2004	74.62			1.0000	75
2006	2,646.27			1.0000	2,646
2007	299.99	20.00	60.00	0.9000	270
2008	2,677.00	20.00	535.40	0.7000	1,874
2009	1,308.00	20.00	261.60	0.5000	654
2010	4,466.89	20.00	893.38	0.3000	1,340
2011	35,893.75	20.00	7,178.75	0.1000	3,589
	47,366.52		8,929.13		10,448

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 18.85

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 484.00 - TRANSPORTATION AND MOBILE EQUIPMENT - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 12-L0					
NET SALVAGE PERCENT.. +25					
1984	474.75	3.27	11.64	0.8992	320
1986	3,385.00	3.46	87.84	0.8823	2,240
1988	4,868.01	3.67	133.99	0.8624	3,149
1989	34,390.39	3.79	977.55	0.8528	21,996
1990	58.50	3.92	1.72	0.8428	37
1991	12,221.00	4.05	371.21	0.8302	7,609
1993	32,789.25	4.34	1,067.29	0.8029	19,745
1994	156,818.41	4.51	5,304.38	0.7892	92,821
1995	15,460.68	4.68	542.67	0.7722	8,954
1996	173,521.43	4.88	6,350.88	0.7564	98,439
1997	66,433.55	5.08	2,531.12	0.7366	36,701
1998	13,106.81	5.31	521.98	0.7168	7,046
1999	122,619.76	5.55	5,104.05	0.6938	63,805
2000	8,679.83	5.83	379.53	0.6704	4,364
2001	244,021.20	6.13	11,218.87	0.6436	117,789
2002	195,342.59	6.46	9,464.35	0.6137	89,911
2003	8,923.42	6.85	458.44	0.5822	3,896
2004	14,617.59	7.28	798.12	0.5460	5,986
2005	166,758.22	7.79	9,742.85	0.5064	63,335
2006	151,016.59	8.39	9,502.72	0.4614	52,259
2007	470,336.39	9.13	32,206.28	0.4108	144,911
2008	137,140.79	10.04	10,326.70	0.3514	36,143
2009	165,961.58	11.23	13,978.11	0.2808	34,952
2010	308,325.84	12.93	29,899.90	0.1940	44,861
2011	53,875.44	16.05	6,485.26	0.0802	3,241
	2,561,147.02		157,467.45		964,510

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.15

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 485.00 - TOOLS AND INSTRUMENTS - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1991	3,238.21			1.0000	3,238
1992	156.97			1.0000	157
1993	1,288.17			1.0000	1,288
1994	3,064.70			1.0000	3,065
1995	1,070.05			1.0000	1,070
1996	10,038.84			1.0000	10,039
1997	8,816.70	6.67	588.07	0.9667	8,523
1998	18,273.33	6.67	1,218.83	0.9000	16,446
1999	63,438.59	6.67	4,231.35	0.8333	52,865
2000	6,165.19	6.67	411.22	0.7667	4,727
2001	8,154.41	6.67	543.90	0.7000	5,708
2002	87,515.51	6.67	5,837.28	0.6333	55,426
2003	23,582.40	6.67	1,572.95	0.5667	13,363
2004	36,733.49	6.67	2,450.12	0.5000	18,367
2005	17,543.91	6.67	1,170.18	0.4333	7,602
2006	55,899.76	6.67	3,728.51	0.3667	20,497
2007	48,284.13	6.67	3,220.55	0.3000	14,485
2008	45,514.89	6.67	3,035.84	0.2333	10,620
2009	37,388.92	6.67	2,493.84	0.1667	6,232
2010	176,091.78	6.67	11,745.32	0.1000	17,609
2011	66,923.57	6.67	4,463.80	0.0333	2,231
	719,183.52		46,711.76		273,558

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 6.50

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 486.00 - COMMUNICATION EQUIPMENT - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1981	12,328.84			1.0000	12,329
1982	997.00			1.0000	997
1983	2,693.00			1.0000	2,693
1985	7,145.00			1.0000	7,145
1986	5,470.00			1.0000	5,470
1987	654.46			1.0000	654
1988	3,067.50			1.0000	3,068
1989	6,505.50			1.0000	6,506
1990	12,083.42			1.0000	12,083
1991	5,466.50			1.0000	5,466
1992	8,287.00			1.0000	8,287
1993	4,525.80			1.0000	4,526
1994	37,148.37			1.0000	37,148
1995	8,886.16			1.0000	8,886
1996	12,061.22			1.0000	12,061
1997	32,424.05	6.67	2,162.68	0.9667	31,343
1998	4,662.16	6.67	310.97	0.9000	4,196
1999	179,948.08	6.67	12,002.54	0.8333	149,956
2000	19,678.50	6.67	1,312.56	0.7667	15,087
2001	11,510.86	6.67	767.77	0.7000	8,058
2002	5,582.26	6.67	372.34	0.6333	3,535
2003	649.95	6.67	43.35	0.5667	368
2004	1,628.00	6.67	108.59	0.5000	814
2005	9,903.90	6.67	660.59	0.4333	4,292
2006	41,356.93	6.67	2,758.51	0.3667	15,164
2007	54,141.89	6.67	3,611.26	0.3000	16,243
2008	59,380.00	6.67	3,960.65	0.2333	13,855
2009	47,209.25	6.67	3,148.86	0.1667	7,868
2010	228,077.07	6.67	15,212.74	0.1000	22,808
2011	49,368.98	6.67	3,292.91	0.0333	1,645
	872,841.65		49,726.32		422,551

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 5.70

YUKON ELECTRICAL COMPANY LIMITED

ACCOUNT 488.20 - HOUSES - GENERAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	--ACCRUED DEPREC.-- FACTOR	AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)
SURVIVOR CURVE.. IOWA 40-R3					
NET SALVAGE PERCENT.. -10					
1981	5,448.00	2.34	140.23	0.7137	4,277
1983	3,328.00	2.38	87.13	0.6783	2,483
1986	12,922.45	2.44	346.84	0.6222	8,844
1988	27,878.53	2.49	763.59	0.5852	17,946
1989	2,150.47	2.51	59.37	0.5648	1,336
1993	9,630.81	2.58	273.32	0.4773	5,056
1994	131,354.79	2.60	3,756.75	0.4550	65,743
1995	1,870.05	2.62	53.89	0.4323	889
1996	12,740.02	2.64	369.97	0.4092	5,735
1997	17,391.56	2.66	508.88	0.3857	7,379
1999	46,813.85	2.69	1,385.22	0.3362	17,313
2000	8,693.67	2.71	259.16	0.3116	2,980
2003	3,969.00	2.76	120.50	0.2346	1,024
2005	21,131.34	2.79	648.52	0.1814	4,217
2006	50,584.94	2.80	1,558.02	0.1540	8,569
2007	51,201.54	2.82	1,588.27	0.1269	7,147
2008	56,889.23	2.84	1,777.22	0.0994	6,220
2009	1,543.92	2.86	48.57	0.0715	121
2010	7,346.76	2.89	233.55	0.0434	351
2011	367.33	2.95	11.92	0.0148	6
	473,256.26		13,990.92		167,636

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.96

YUKON ELECTRICAL COMPANY LIMITED

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

ACCT	GP	AVG. AGE	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	ACCRUED DEPRECIATION
42200		15.5	215,286.13	2.41	5,196.03	65,962
42300		9.8	1,875,073.03	2.32	43,489.59	348,379
42500		5.5	1,458,434.89	2.53	36,861.87	168,738
42600		20.1	105,192.21	2.55	2,686.68	53,335
42700		8.5	68,656.70	4.23	2,906.88	21,413
44200	1	26.0	37,487.88	2.65	991.85	24,477
44200	2	9.8	167,738.94	3.14	5,262.00	48,651
44200	3	31.3	42,281.93	3.06	1,295.59	34,343
44200	4	7.5	608,472.09	3.28	19,941.87	127,125
44200	5	22.8	187,900.18	2.72	5,116.76	112,197
44200	6	30.0	48,891.66	2.61	1,274.47	37,202
44200	7	13.5	171,221.40	3.03	5,183.92	63,121
44200	8	9.7	247,965.51	3.14	7,774.80	70,692
44200	9	18.2	22,503.27	2.85	641.35	10,898
44200	10	12.7	37,985.88	3.28	1,246.46	11,481
44200	11	23.2	359,392.86	2.71	9,727.14	224,332
44200	99	40.5	10,662.39	2.24	239.26	9,690
44200 TOTAL		14.8	1,942,503.99	3.02	58,695.47	774,209
44400	1	15.5	92,858.54	3.51	3,262.59	48,830
44400	2	21.6	40,394.23	3.45	1,394.84	30,085
44400	3	13.1	105,478.32	5.09	5,367.02	65,461
44400	4	13.6	619,132.40	3.56	22,066.78	298,698
44400	5	13.7	215,086.84	3.52	7,563.49	99,570
44400	6	30.0	129,302.01	3.28	4,240.12	111,464
44400	7	13.0	85,125.62	3.59	3,056.01	39,551
44400	8	8.1	65,107.14	3.59	2,336.04	17,913
44400	9	20.7	63,430.02	3.46	2,194.49	45,174
44400	10	7.5	99,862.71	3.62	3,619.02	27,143
44400	11	4.9	747,817.56	3.61	27,011.23	129,740
44400	99	23.5	25,562.13	3.40	868.09	20,399
44400 TOTAL		11.8	2,289,157.52	3.62	82,979.72	934,028
44500	1	18.9	535,779.26	4.03	21,611.00	404,185
44500	2	20.8	419,543.17	3.92	16,443.03	340,161
44500	3	7.2	488,076.41	7.10	34,656.54	154,040
44500	4	16.4	60,096.50	4.22	2,537.61	41,010
44500	5	10.9	1,223,712.97	4.47	54,655.45	582,440
44500	6	17.2	474,055.94	4.16	19,739.04	330,834
44500	7	22.7	189,753.15	3.77	7,157.63	161,805
44500	8	17.4	45,677.37	4.03	1,842.11	27,331
44500	9	11.0	241,047.18	4.42	10,642.57	108,696
44500	10	18.5	762,033.60	4.09	31,182.41	576,875
44500	11	17.4	2,169,195.37	4.05	87,925.26	1,450,577
44500	99	15.0	568,500.41	4.16	23,634.95	333,611
44500 TOTAL		15.7	7,177,471.33	4.35	312,027.60	4,511,565
44600	1	11.4	173,365.48	3.06	5,301.72	57,897
44600	2	11.3	101,158.38	3.07	3,101.64	34,682
44600	3	13.4	284,627.18	4.52	12,854.07	142,466
44600	4	19.8	94,951.86	2.82	2,676.90	47,493
44600	5	20.6	119,365.14	2.83	3,378.65	68,323
44600	6	11.8	431,734.53	3.49	15,056.25	164,126

YUKON ELECTRICAL COMPANY LIMITED

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

ACCT	GP	AVG. AGE	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	ACCRUED DEPRECIATION
44600	7	13.1	124,871.74	3.02	3,768.00	48,576
44600	8	13.0	70,424.93	3.02	2,126.40	26,610
44600	9	10.9	93,560.14	3.08	2,880.23	31,055
44600	10	15.8	54,416.63	2.96	1,611.49	25,006
44600	11	19.7	578,189.22	2.84	16,449.48	305,256
44600	99	16.9	87,652.04	2.91	2,554.96	40,799
44600 TOTAL		15.2	2,214,317.27	3.24	71,759.79	992,289
44700	1	6.1	48,602.64	2.86	1,388.11	8,191
44700	2	2.8	7,366.11	3.00	221.35	535
44700	3	13.0	28,047.98	4.66	1,306.05	13,174
44700	4	27.7	2,454.15	2.38	58.38	1,482
44700	5	14.8	171,495.51	2.66	4,560.58	66,532
44700	6	11.3	61,485.35	3.53	2,169.91	20,121
44700	7	7.1	9,639.21	2.83	273.19	1,775
44700	8	3.1	84,681.90	2.99	2,532.66	6,985
44700	9	9.8	11,923.96	2.75	328.29	3,190
44700	10	4.6	69,778.10	2.89	2,014.47	9,302
44700	11	9.2	258,429.56	2.75	7,094.76	61,919
44700	99	4.6	92,169.51	2.82	2,603.32	12,008
44700 TOTAL		8.9	846,073.98	2.90	24,551.07	205,214
45700		22.3	1,384,421.27	2.26	31,326.39	689,303
47100		8.0	1,267,608.43	1.51	19,155.05	151,638
47300		13.0	30,231,546.31	4.21	1,271,958.20	15,702,296
47400		12.6	20,514,612.41	4.17	855,624.87	10,498,681
47410		16.3	2,849,452.51	2.59	73,754.26	1,125,671
47500		12.4	20,982,588.53	3.62	759,511.53	9,111,686
47510		12.1	2,953,077.19	2.88	84,924.28	1,016,443
47610		8.1	1,683,985.25	8.00	134,650.21	682,328
47630		2.8	67,646.33	7.65	5,174.69	14,259
47710		20.8	3,131,073.05	2.78	86,966.89	1,765,608
47810		12.8	9,147,521.61	3.80	347,923.62	4,196,129
47820		28.7	284,738.28	3.09	8,784.22	246,947
47910		12.1	24,427,769.16	2.66	649,017.76	7,365,548
48200		18.5	3,459,315.31	2.65	91,700.62	1,660,879
48300		5.8	172,793.39	6.05	10,447.77	62,511
48320		1.1	47,366.52	18.85	8,929.13	10,448
48400		7.9	2,561,147.02	6.15	157,467.45	964,510
48500		5.8	719,183.52	6.50	46,711.76	273,558
48600		8.1	872,841.65	5.70	49,726.32	422,551
48820		12.3	473,256.26	2.96	13,990.92	167,636
GRAND TOTAL		14.4	145,424,111.05	3.68	5,348,900.64	64,203,762

CW-YECL-35

Reference: Depreciation Study, Application, Section 7, Attachment 1 – Depreciation Study

In order to better understand the historical relationships reflected in net salvage and life analyses, it is necessary to have a better understanding of the type of investment currently in place, the type of investment recently retired, and various accounting practices.

Request:

(a) Please produce all additional working papers or other documentation supporting the depreciation study set out in the Application at Section 7, Attachment 1 including any notes of discussions that Gannett Fleming or Mr. Larry Kennedy had with YECL or employees of YECL.

Response:

(a) The complete basis for Yukon Electrical's position on appropriate Depreciation rates is the Depreciation Study itself, which has been filed and provides the full and comprehensive treatment of the issue. Yukon Electrical is not relying on any further documents or discussions in support of its position.

LE-YECL-1

Reference: Section 1 Introduction, Page 1-6

In "**Key Assumptions**" the labour inflation in each of the test years of 2013, 2014, and 2015 is stated to be 3.5%.

Request:

(a) Is the 3.5% figure for 2013 relative to the labour rates last approved by Yukon Utilities Board ("Board" or "the Board") for the 2009 test year?

(b) If not please explain on what figure this percentage increase is to be calculated.

(c) Please explain why labour inflation is consistently above general inflation (2008-2009 GRA and each year in this GRA).

Response:

(a) No.

(b) The 3.5% increase is calculated relative to the 2012 actual labour rates paid to employees.

(c) Labour inflation is consistently above general inflation as that is what Yukon Electrical is required to offer to attract and retain the skilled employees necessary. Salaries and wages are only one component of total compensation. Yukon Electrical, with support from the ATCO Electric Human Resources group, works to ensure that the total compensation offered to employees remains competitive with other employers, not only in the Yukon but also in other market areas (such as Alberta) in which Yukon Electrical competes for skilled labour.

For additional information on the derivation of the labour inflation rates, please refer to YUB-YECL 17(c).

LE-YECL-2

Reference: Section 1 Introduction, Page 1-8

Regarding the table of staff positions:

Request:

(a) Please confirm that relative to Board approved 2009 staffing the increase staff compliment to the end of 2012 is about 15.8%, and forecasted to the end of 2015 is 27.8%.

(b) For each of the Board approved 2009 figures for 2012 year-end actuals and the YECL 2015 projected year-end figures, please provide the number of retail customers, the number of capital projects, and the value of capital projects. Please calculate the percentage increases in each of the number of retail customers, number of capital projects, and value of capital projects in 2012 relative to 2009, and 2015 relative to 2009.

(c) Please discuss the comparative change in the percentages calculated in (a) to the percentage changes calculated in (b).

Response:

(a) Confirmed.

(b) Please refer to LE-YECL-2(b) Attachment 1.

(c) In reviewing statistics from 2009 to 2012, there was an increase in labour complement of 15.9% during the period. During the same time period, there was an increase in retail customers of 9.3%, an increase in the annual number of capital projects of 38.3%, an increase of 133.3% in the value of capital projects and an increase in rate base of 21.3%.

A review of the statistics for the period from 2009 to 2015 indicates an increase in labour compliment of 27.8%. During the same period, there was an increase in retail customers of 13.0%, an increase in the annual number of capital projects of 73.8%, an increase of 233.0% in the value of capital projects and an increase in rate base of 95.7%.

This large amount of capital work has increased workloads significantly in the engineering, construction and warehouse groups. Along with a growing customer base, the growth of the electrical system has an associated increase in the requirements for additional operations, maintenance and customer service support. These groups are all supported by administration and financial services.

For additional information please refer to WL-YECL-5(a).

The Yukon Electrical Company Limited

Percentage Growth in Labour Complement, Number of Customers, Number of Capital Projects, Value of Capital Projects and Rate Base

	Reference	2009	2012	% Change
Labour Complement	Page 1-8	57.43	66.53	15.8%
Retail Customers	Schedule 2.1, line 28	15,573	17,026	9.3%
Number of Capital Projects		313	433	38.3%
Value of Capital Projects	Schedule 9.1, line 31	6,253,000	14,590,000	133.3%
Rate Base	Schedule 8.5, line 31	49,478	60,033	21.3%

	Reference	2009	2015	% Change
Labour Complement	Page 1-8	57.43	73.39	27.8%
Retail Customers	Schedule 2.1, line 28	15,573	17,595	13.0%
Number of Capital Projects		313	544	73.8%
Value of Capital Projects	Schedule 9.1, line 31	6,253,000	20,820,000	233.0%
Rate Base		49,478	96,812	95.7%

LE-YECL-3

Reference: Section 3 Purchase Power, Page 3-1

Footnote 1 *"Yukon Electrical was directed in Board Order 2009-2 to capitalize the incremental purchased power costs incurred due to Fish Lake rebuilds in 2008/2009. Consistent with this order, Yukon Electrical has capitalized the incremental purchase power costs incurred for the period in which Fish Lake Unit #1 was out of service after the catastrophic failure in March 2010"*

Request:

(a) How much down time and purchase power would have been incurred had there not been a catastrophic failure?

(b) Should insurance or a reserve for injuries or damages not cover the loss of production from a catastrophic failure that would not have been incurred with a planned / scheduled rebuild rather than being capitalized? Please explain.

Response:

(a) On an annual basis, this plant would be taken off line for approximately 14 days to complete regular scheduled maintenance. This quantum of days translates into approximately $15,000 of additional purchased power costs.

(b) Yukon Electrical capitalized these costs, rather than charging them to the reserve for injuries and damages, to be consistent with the previous direction received regarding purchase power associated with a rebuild in Board Order 2009-2:

> The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time.

Further, the Board notes LE's argument that indicated that incremental power purchases incurred because of the required rebuilds should be clearly documented. The Board agrees that this is a reasonable approach. Therefore, the Board directs YECL in its refiling to capitalize the forecast purchased power costs associated with the Fish Lake rebuild and to not treat these costs as an expense item in the test years.

-Board Order 2009-2, Reasons for Decision, Page 10 of 49

LE-YECL-4

Reference: Section 3 Purchase Power, Page 3-2

"Deferral Account (b) Diesel Contingency Fund (DCF)"

Request:

(a) Please explain how YECL views the impact of the unavailability of Fish Lake Hydro Unit #1 in 2013 on the DCF.

Response:

(a) The Diesel Contingency Fund (DCF), as previously approved, serves to stabilize Yukon Energy's and Yukon Electrical's costs to serve firm load on the grid due to variances in actual water flows relative to approved long term averages. As such, it is Yukon Electrical's position that any impact due to the unavailability of Fish Lake Hydro Unit #1, because it is not due to a variance in water flows, will not be incorporated into the DCF calculations until such time as Hydro Unit #1 is back up and operational.

LE-YECL-5

Reference: Section 5 Operations and Maintenance Expenses, Page 5-1

Request:

Please provide an expanded table that includes the 2008 and 2009 actuals.

Response:

Please refer to YUB-YECL-16 Attachment 1 for an expanded table that includes 2008 and 2009 actuals.

LE-YECL-6

Reference: Section 5 Operations and Maintenance Expenses, Page 5-1

Request:

Based on the expanded table requested above please provide a table showing each of the component costs and the total O&M costs on a $ per MWh of sales plus losses basis.

Response:

Please refer to LE-YECL-6 Attachment 1.

The Yukon Electrical Company Limited
Operations and Maintenance Expenses per MWh

Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
Total Generation and Purchases MWh (per Sch 3.2, line 5)	**310,648**	**312,133**	**309,725**	**315,664**	**336,955**	**338,777**	**349,151**	**355,682**
Production								
62600 - Hydro Generation	0.30	0.39	0.36	0.34	0.46	0.94	1.20	1.28
64000 - Supervision and Engineering Diesel	0.19	0.19	0.20	0.20	0.20	0.19	0.19	0.19
64600 - Diesel Generation	1.15	1.36	1.57	1.90	1.35	1.53	2.02	2.01
82600 - Hydro Maintenance	0.16	0.11	0.06	0.20	0.31	0.14	0.14	0.14
84600 - Diesel Maintenance	3.34	3.24	2.95	3.21	3.54	3.59	3.54	3.55
	5.14	5.28	5.14	5.86	5.87	6.40	7.09	7.17
Distribution								
87000 - Supervision	0.77	0.87	0.76	0.77	0.78	0.88	0.87	0.88
87100 - Brushing	1.06	1.07	1.15	0.90	1.61	1.19	1.18	1.18
87200 - Vehicle Depreciation	(0.31)	(0.46)	(0.49)	(0.51)	(0.50)	(0.54)	(0.54)	(0.54)
87300 - Maintenance	4.30	5.38	5.71	5.73	5.75	5.87	5.83	5.99
87310 - Service to Outside Parties	0.23	0.27	0.21	0.29	0.30	0.30	0.30	0.30
87400 - Underground Line Maintenance	0.33	0.38	0.31	0.29	0.61	0.51	0.51	0.57
87500 - Meter and Meter Testing	0.51	0.38	0.30	0.32	0.32	0.26	0.26	0.26
87700 - Transformer Repair and Replacement	0.09	0.04	0.12	0.15	0.33	0.23	0.23	0.24
87800 - Street Light Maintenance	0.54	0.53	0.54	0.51	0.54	0.57	0.56	0.59
	7.52	8.45	8.60	8.42	9.74	9.27	9.21	9.49
General								
88400 - Communication	0.03	0.06	0.03	0.03	0.05	0.04	0.04	0.04
88800 - Maintenance Company-Owned Houses	0.10	0.04	0.06	0.05	0.05	0.05	0.05	0.05
88900 - Maintenance Warehouse and Office	0.35	0.36	0.40	0.36	0.44	0.38	0.38	0.38
	0.48	0.45	0.48	0.45	0.53	0.47	0.46	0.47
Public Information								
70100 - Public Information Administration	0.28	0.23	0.15	0.11	0.08	0.08	0.08	0.08
70200 - General Public Information	0.05	0.16	0.19	0.24	0.32	0.37	0.36	0.37
	0.34	0.39	0.33	0.35	0.41	0.45	0.44	0.45

The Yukon Electrical Company Limited
Operations and Maintenance Expenses per MWh

Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
Customer Accounting								
71000 - Supervision	0.10	0.17	0.13	0.11	0.16	0.16	0.16	0.16
71100 - Customer Applications and Service Orders	1.15	1.43	1.32	1.30	1.32	1.41	1.46	1.53
71200 - Meter Reading	1.71	1.74	1.72	1.46	1.44	1.66	1.65	1.42
71300 - Customer Billing and Accounting	1.82	2.25	2.25	2.23	2.06	2.21	2.19	2.22
71400 - Revenue Collections	0.67	0.56	0.53	0.53	0.54	0.67	0.67	0.67
71500 - Collection of Delinquent Accounts	0.42	0.31	0.38	0.35	0.37	0.41	0.41	0.41
71800 - Provision for Uncollectible Accounts	0.11	0.11	0.14	0.11	0.11	0.11	0.10	0.10
	5.98	6.58	6.48	6.09	5.98	6.64	6.64	6.51
Administration and General								
72100 - Administrative	4.88	4.82	5.31	5.68	6.02	6.81	7.01	6.87
72200 - Administrative Corporate	0.09	0.48	0.59	0.22	0.58	0.40	0.39	0.39
72300 - Insurance	0.66	0.73	0.69	0.77	0.73	0.77	0.58	0.39
72400 - Injuries & Damages	0.24	0.31	0.28	0.27	0.26	0.37	0.36	0.35
72500 - Employee Expenses	0.74	0.75	0.82	0.81	0.74	0.82	0.81	0.81
72600 - Training and Safety	1.00	1.30	1.30	1.23	1.35	1.38	1.37	1.39
72700 - Relocation	0.35	0.17	0.69	0.65	0.20	0.47	0.47	0.48
72800 - Miscellaneous General	0.02	0.00	-	-	0.00	0.00	0.00	0.00
72900 - Audit/Legal Fees & Special Studies	0.23	0.64	0.36	0.24	0.42	0.39	0.45	0.39
	8.21	9.20	10.04	9.87	10.29	11.41	11.43	11.08
Total Operations and Maintenance Expenses per MWh	**27.66**	**30.35**	**31.08**	**31.04**	**32.82**	**34.64**	**35.28**	**35.16**

LE-YECL-7

Reference: Section 5 Operations and Maintenance Expenses, Page 5-5

Discontinuance of Third Party Distribution Line (Property Insurance) "*Going back to the year 2008, Yukon Electrical has researched its claims history ...*"

Request:

A 5 year claim history in which the annual premiums do not add up to one deductible would seem to be too short. Please provide a 20 year (or more) claim history.

Response:

Yukon Electrical has reviewed its claim history going back to 1993 and is able to confirm there have been no claims on the third party distribution line insurance policy through to present.

LE-YECL-8

Reference: Section 5 Operations and Maintenance Expenses, Schedule 5.3

Request:

(a) Line 3: ATCO Electric After Hours - call Answering: Please explain and justify the doubling of costs during the test years from actuals in 2012 (and earlier).

(b) Line 14: ATCO Electric Financial Reporting and Regulatory Support: Please explain in detail and justify the very substantial increases in costs of this line item.

Response:

(a) Please refer to YUB-YECL-6(e) for an explanation for the change in After Hours – Call Answering costs from 2012 to 2013.

(b) Financial Services and Regulatory Support costs increased from 2010 to 2011 as a result of the Supervisor, Financial Services position being relocated from Whitehorse to Edmonton in the fourth quarter of 2011. Prior to the relocation, the position was filled by an employee of Yukon Electric and, as a result, was not considered a charge from an affiliate.

Financial Services and Regulatory Support costs increased from 2011 to 2012 due to the full year impact of the relocation of the Supervisor, Financial Services as discussed above, as well as the addition of the Corporate Accountant at the beginning of the year and the Manager, Financial Accounting & Reporting, North of 60 mid-year. Please refer to YUB-YECL-22(j) and YUB-YECL-22(k) for further information on the need for the Manager, Financial Accounting and Reporting, North of 60 as well as the Corporate Accountant.

Financial Services and Regulatory Support costs increased from 2012 to 2013 due to the full year impact of the Manager, Financial Account & Reporting, North of 60 discussed above.

Financial Services and Regulatory Support costs increase from 2013 to 2014 and 2014 to 2015 as a result of inflation.

LE-YECL-9

Reference: Section 7 Depreciation, Page 7-2

Deferral on Depreciation Parameters

Request:

(a) YECL is under the same IFRS requirements as Yukon Energy yet YECL's approach appears to be very different. Please explain the differences in approach, explain why YECL wants to take the approach proposed here, and show how it is beneficial to ratepayers.

(b) Please explain why the changes discussed on pages 7-2 to 7-4 could not be accommodated in appropriate changes in a GRA every 3 years if YECL proposes to make adjustments only if the significant change takes place over 2 or 3 years in any case?

Response:

(a) Notably, Yukon Energy had not yet transitioned to IFRS at the time of filing of its 2012/2013 GRA. When it implements IFRS, Yukon Energy will have the same requirement as Yukon Electrical to review its depreciation parameters annually and implement new depreciation rates if necessary. Yukon Electrical implemented IFRS in 2011 and has since dealt with increased administrative burden due to keeping two sets of financial records. Because of this experience, Yukon Electrical has requested the deferral on depreciation parameters in order to harmonize IFRS and regulatory accounting in the area of depreciation to avoid even further complexity and accounting costs due to yet another difference between the two sets of financial records and, in turn, the need for more accounting and higher accounting related costs.

(b) Significant changes in the expected life of assets or gross salvage and costs of retirement of assets can be caused by various events, including changes in technology or the life experience of the asset in the field. Such an event or events could have an immediate impact on the expected life of assets or gross salvage and costs of retirement in the same year in which in which it occurs. Conversely, such event or events could have an impact on the expected life of

assets or gross salvage and costs that is not immediate but is only revealed after several years of data and trend information is analyzed. Yukon Electrical would be required to update its depreciation parameters if either type of situation were to occur, not only for significant changes that take place over 2 or 3 years.

If a change to depreciation parameters is required based on Yukon Electrical's annual review of depreciation parameters as described on pages 7-2 and 7-3 of the Application, Yukon Electrical would be obligated to adjust the depreciation parameters and the resulting depreciation rates for financial statement purposes in order to obtain a clean audit opinion under IFRS. While the update to the depreciation parameters for regulatory purposes could wait until Yukon Electrical's next GRA is filed, this delay would create yet another difference between Yukon Electrical's IFRS and regulatory financial records, which, in turn, creates the need for more accounting and higher accounting related costs.

LE-YECL-10

Reference: Section 7 Depreciation, Schedules 7.2 to 7.4

Request:

Please explain in detail why the proposed depreciation rates for a number of asset classes vary so much from year to year within the test period.

Response:

The reason for depreciation rates varying from year to year is due to 1) the effects of the Equal Life Group (ELG) procedure, 2) reduced period of recovery for applicable life span accounts[i] and 3) capital additions and retirements for each forecast year. LE-YECL-10 Attachment 1 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2013. As shown, the total original cost in this account as of the end of 2012 is $262,558 with the applicable vintage details. The total expected depreciation expense (i.e. annual accrual) adjusted for net salvage is forecast to be $6,307. This expected depreciation expense divided by the total original cost of $262,558 results in a forecast depreciation rate of 2.40% for 2013. LE-YECL-10 Attachment 2 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2014. Consistent with the ELG procedure, as a particular vintage ages each successive year's depreciation rate for that vintage will decrease accordingly and if no capital activity occurs during a year then the composite account depreciation rate will similarly decrease. As this account is also using a Life Span grouping with a terminal year of 2052, the recovery period for each successive vintage's additions are compressed resulting in higher associated depreciation rates. For this account, approximately $197,000 is forecast to be added during 2013. This significant addition attracts a vintage depreciation rate of 3.04%. The investment weighted calculation of vintage depreciation expense produces a composite depreciation rate of 2.79%. LE-YECL-10 Attachment 3 shows the detailed calculations for Account 42200 – Hydraulic Production Structures for the year 2015. The forecast addition for the 2014 vintage is $167,000. This large addition attracts a vintage depreciation rate of 3.10% due to the ELG methodology described above and the compressed time to recover the investment for the 2014 vintage by the lifespan retirement date of 2052. This results in an account composite depreciation rate of 2.91%.

[i] Please refer to YUB-YECL-81(b) for a discussion on lifespan analysis.

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2013
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2013

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.43	152.47	.6006	6,404
1987	67,520.32	1.73	1,168.10	.4498	30,371
1989	57,730.91	1.78	1,027.61	.4272	24,663
1991	308.57	1.83	5.65	.4026	124
1992	11,156.06	1.86	207.50	.3906	4,358
2000	10,832.25	2.14	231.81	.2782	3,014
2010	21,239.34	2.73	579.83	.0819	1,740
2011	83,108.03	2.84	2,360.27	.0568	4,721
			5,733.24		75,395
NET SALVAGE ADJUSTMENT			573.32		7,540
TOTAL	262,557.87		6,306.56		82,935

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.40

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2012

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2013

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		16.0	262,557.87	2.40	6,307	82,935
GRAND TOTAL		16.0	262,557.87	2.40	6,307	82,935

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2014
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2014

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.42	151.41	.6106	6,510
1987	67,520.32	1.72	1,161.35	.4644	31,356
1989	57,730.91	1.77	1,021.84	.4425	25,546
1991	308.57	1.82	5.62	.4186	129
1992	11,156.06	1.85	206.39	.4070	4,541
2000	10,832.25	2.13	230.73	.2982	3,230
2010	21,239.34	2.69	571.34	.1076	2,285
2011	83,108.03	2.78	2,310.40	.0834	6,931
2013	197,000.00	3.04	5,988.80	.0304	5,989
			11,647.88		86,517
NET SALVAGE ADJUSTMENT			1,164.79		8,652
TOTAL	459,557.87		12,812.67		95,169

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.79

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2013

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2014

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		10.1	459,557.87	2.79	12,813	95,169
GRAND TOTAL		10.1	459,557.87	2.79	12,813	95,169

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

PROGRAM OPTIONS IN EFFECT:

CALCULATION MONTH AND YEAR	06-2015
CALCULATION PROCEDURE	1 = E.L.G.
MINIMUM EXPECTANCY	0.00
ADJUST FOR NET SALVAGE	YES

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

ACCOUNT 42200
HYDRAULIC PRODUCTION - STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2015

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	-ACCRUED DEPREC.- FACTOR (5)	AMOUNT (6)
INTERIM SURVIVOR CURVE.. IOWA 72-R2					
PROBABLE RETIREMENT YEAR.. 12-2052					
NET SALVAGE PERCENT.. -10					
1971	10,662.39	1.41	150.34	.6204	6,615
1987	67,520.32	1.71	1,154.60	.4788	32,329
1989	57,730.91	1.76	1,016.06	.4576	26,418
1991	308.57	1.81	5.59	.4344	134
1992	11,156.06	1.84	205.27	.4232	4,721
2000	10,832.25	2.12	229.64	.3180	3,445
2010	21,239.34	2.66	564.97	.1330	2,825
2011	83,108.03	2.74	2,277.16	.1096	9,109
2013	197,000.00	2.94	5,791.80	.0588	11,584
2014	167,000.00	3.10	5,177.00	.0310	5,177
			16,572.43		102,357
NET SALVAGE ADJUSTMENT			1,657.24		10,236
TOTAL	626,557.87		18,229.67		112,593

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.91

YUKON ELECTRICAL COMPANY LIMITED 8/02/13

SURVIVING AT DECEMBER 31, 2014

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
AS OF 6-30-2015

ACCT	GRP	AVG AGE	ORIGINAL COST	ANNUAL ACCRUAL RATE	ACCRUAL AMOUNT	ACCRUED DEPRECIATION
422.00		8.4	626,557.87	2.91	18,230	112,593
GRAND TOTAL		8.4	626,557.87	2.91	18,230	112,593

LE-YECL-11

Reference: Section 8 Return on Rate Base, Page 8-4 and 8-5

Business Risk Analysis

Request:

(a) Does YECL face greater or less business risk than Yukon Energy? Please explain.

(b) For the period of 2008 to 2012 please provide a table showing Board approved and actual ROEs achieved by YECL.

Response:

(a) Looking backwards, Yukon Electrical has acknowledged that Yukon Energy relative to Yukon Electrical has more risk. On a go forward basis, however, it is difficult to provide a definitive answer as Yukon Electrical's generation assets are forecast to become a larger percentage of its asset mix as compared to 2008. The presence of generation assets in rate base generally increases the business risk relative to a pure distribution utility, as the operational risks associated with generation exceed those of wires operations. Please refer to the following table for Yukon Electrical's actual asset mix in 2008, 2012 as well as forecast through to 2015.

	Actual		GRA		
	2008	**2012**	**2013**	**2014**	**2015**
Generation	14%	13%	16%	18%	19%
Distribution	79%	81%	77%	75%	74%
Other	7%	6%	7%	7%	7%
Total	100%	100%	100%	100%	100%

In YUB-YECL-31, Yukon Electrical has also identified changes to its market demand and operational costs that have resulted in Yukon Electrical's business risk increasing modestly since 2008.

Finally in response to this question, Yukon Electrical notes that Yukon Energy has maintained the same capital structure since 1992 and did not request or provide evidence to support a change to it as part of its 2012-2013 GRA. Further to this, Yukon Energy stated the following in its 2012-2013 GRA reply argument:

> Yukon Energy notes that the current proceeding provides no reasonable or tested evidence upon which the Board could support a revision of YEC's capital structure, or assess YEC's capital structure based on AUC methods.

In dealing with this matter, the Board stated the following in Board Order 2013-01:

> YEC's capital structure of 60-percent debt and 40-percent equity has been previously approved by the Board, most recently through Board Order 2009-8. Nothing on the record of this proceeding persuades the Board to alter the applied-for and previously approved capital structure for YEC.

Contrary to the above noted evidentiary situation, this Application continues to rely on the business risk expert evidence from Yukon Electrical's 2008-2009 GRA as well as regulatory decisions in the Northwest Territories and British Columbia. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(b) Please refer to LE-YECL-11(b) Attachment 1.

Yukon Electrical 2008 - 2012
Board Approved vs. Actual Return on Equity

Year	2008	2009	2010	2011	2012
Approved	9.08%	8.93%	N/A	N/A	N/A
Actual	7.03%	11.35%	10.54%	10.74%	10.18%
Difference	-2.05%	2.42%	N/A	N/A	N/A

LE-YECL-12

Reference: Section 8 Return on Rate Base, Page 8-6

Forecast Long Term Date [sic] Rates

Request:

Please provide a list of the financial institutions referred to and each of their forecasts for long term debt rates for the period 2013 to 2020.

Response:

The financial institutions referred to included BMO Capital Markets, TD Economics, RBC Economics and Consensus Forecasts. Please refer to WL-YECL-18(c) Attachments 1 through 4 for the latest available forecasts used in determining the long term debt rate forecast from 2013 to 2015.

LE-YECL-13

Reference: Section 9 Capital Additions, Page 9-3

Street and Sentinel Lights

Request:

Please confirm that all new street and sentinel lights will be LED lights as they are more energy efficient.

Response:

Not confirmed.

Although ATCO Electric has a stock item 43W LED light to replace 100W street lights, Yukon Electrical has partnered with YEC in a joint pilot project study to determine the best suited LED streetlight technology for the Yukon. This pilot project is currently testing four different LED lights including the selected ATCO Electric 43W LED light. The pilot project study will be completed by the end of 2013.

In addition to the pilot project study, Yukon Electrical has discussed with ATCO Electric the benefits and performance of this light in ATCO Electric's northern Alberta communities. To date, Yukon Electrical has not installed LED streetlights other than a select few for testing purposes. Yukon Electrical has determined that it is prudent to have thorough testing completed to ensure that the LED lights perform to an appropriate standard in light intensity and lighting patterns for the Yukon.

LE-YECL-14

Reference: Section 9 Capital Additions, Page 9-54

Destruction Bay

Request:

Please describe the features of the capital work completed in the Destruction Bay power plant that will enable the wind energy project being developed by the Kluane First Nation to be incorporated into the power system there and displace a maximum possible amount of diesel generation.

Response:

The planned replacement of the control system (PLC) in 2014 (please refer to page 9-54 of the Application) will allow Yukon Electrical to integrate additions to the system from another source. The present control system will not allow this addition/integration.

LE-YECL-15

Reference: Section 11 Prior Board Directions, Attachment 2 Pages 11-15-16, and Page 1-6

Request:

For each of the utility filings listed here please also provide the labour inflation rates requested by these utilities.

Response:

ATCO Electric (2011-2012 GTA)

- AE requested approval of labour inflation rates of 3.0% for each of the 2011 and 2012 test years.

AltaLink (2011-2012 GTA)

- AML requested approval of labour inflation rates of 4.24% for salaries and wages (labour), 4.50% for union, 4.00% for non-union and 3.00% for executives for each of the 2011 and 2012 test years.

EPCOR (2012 GTA)

- EDTI requested approval of labour inflation rates of 4.0% for non-union labour, 3.0% for Civic Service Union 52 labour, and 3.0% for International Brotherhood of Electric Workers for 2012.

Fortis (2012 GTA)

- FAI requested approval of labour inflation rates of 3.0% for association labour and 4.0% for non-association labour for 2012.

Northland Utilities (NWT) (2011-2013 GRA)

- NUL (NWT) requested approval of labour inflation rates of 3.5%, 3.0%, and 3.0% for the 2011, 2012, 2013 test years, respectively.

Northland Utilities (NUY) (2011-2013 GRA)

- NUL (NUY) requested approval of labour inflation rates of 3.5%, 3.0%, and 3.0% for the 2011, 2012, 2013 test years, respectively.

LE-YECL-16

Reference: Section 13 Business Cases, Business Case #2

Request:

(a) What is the nameplate capacity of the new turbine-generator?

(b) Page 4 of 8: this page is virtually unreadable; please provide a copy of this diagram in higher resolution PDF format.

(c) Page 5 of 8: please indicate whether the insurance proceeds paid for the additional wholesale power that YECL had to purchase.

(d) Page 8 of 8: please provide a PDF of the complete spreadsheet showing all of the parameters and the LCOE calculation. Please also provide this spreadsheet in Excel format with all of the formulae intact.

(e) Please provide a PDF drawing of the Fish Lake hydro system indicating all structures for which there are Business Case upgrades or replacements.

(f) Please provide a listing of all Fish Lake system related actual and planned capital costs incurred since the 2009 test year up to and including 2015, whether included in Business Cases or elsewhere.

Response:

(a) 800kW.

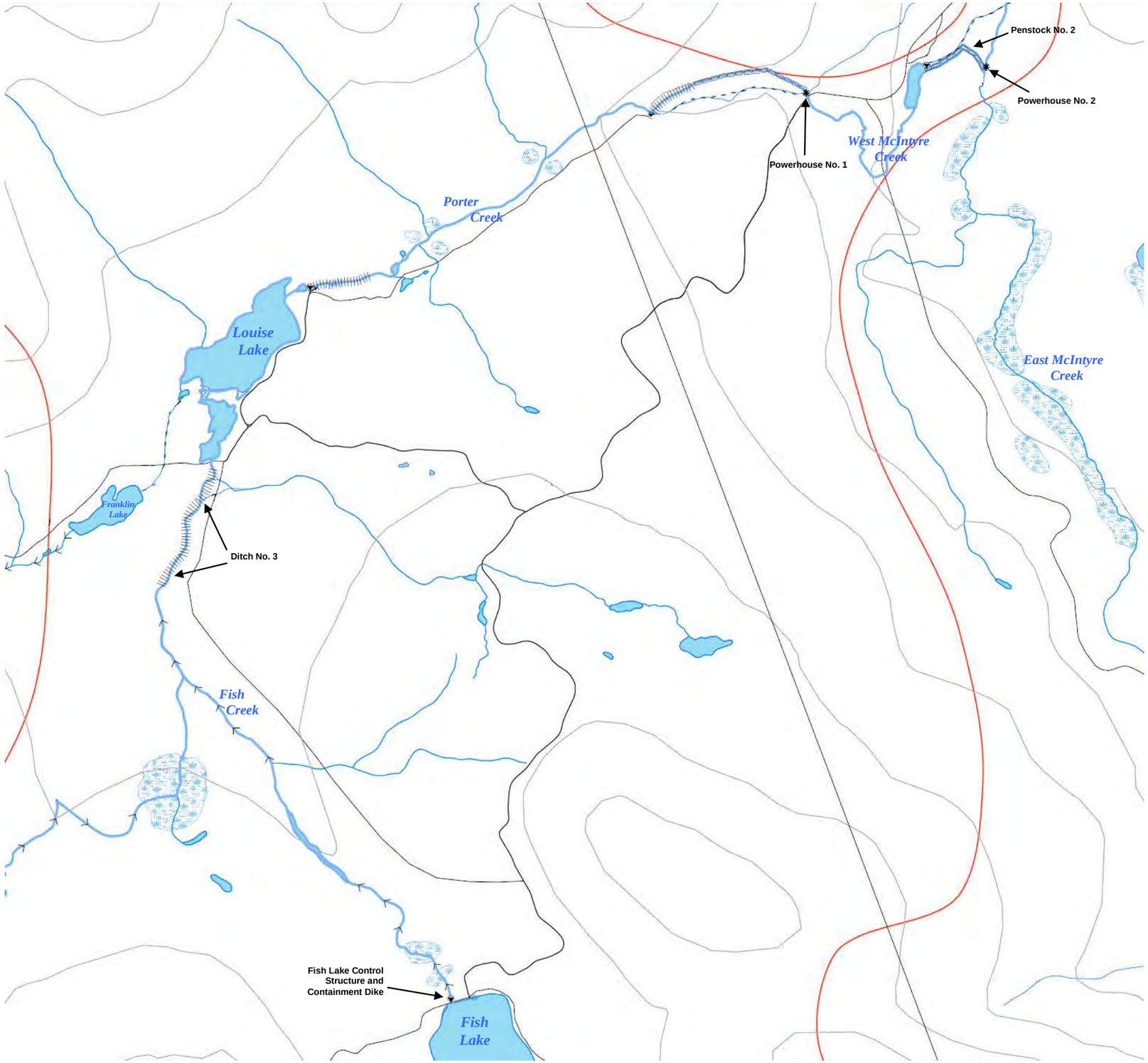
(b) Please refer to LE-YECL-16(b) Attachment 1.

(c) No, the insurance proceeds did not cover wholesale power purchases.

(d) Please refer to the response to information request YUB-YECL-37(a).

(e) Please refer to LE-YECL-16(e) Attachment 1.

(f) Please refer to YEC-YECL-16(a) Attachment 1.


Penstock No. 2
Powerhouse No. 2
Powerhouse No. 1
West McIntyre Creek
Porter Creek
Louise Lake
East McIntyre Creek
Franklin Lake
Ditch No. 3
Fish Creek
Fish Lake Control Structure and Containment Dike
Fish Lake

480000 485000 490000 495000

6735000 6730000 6725000

BC # 2
Plant #1
Spillway
Channel
Headpond #1
Ditch #1
Plant #2
Ditch #2
Louise Lake
Control Structure
Porter Creek
Maintenance Trail
Ditch #1 Overflow
Spillway
Headpond #2
(Pumphouse Pond)
BC # 1
Louise Lake
Auxiliary Spillway
Louise
Lake
Louise Lake Road
Louise Lake
Containment Dyke
Fish Lake Rd
Franklin
Lake
Franklin Lake Road
Ditch #3 Drop Box
BC # 9
Ditch #3
Ditch #3 Auxiliary
Spillway
Fish Creek
Fish Lake Dyke
and Control Gate
BC # 7
Fish
Lake
McIntyre Creek
Porter Creek
West McIntyre Ck
East McIntyre Creek
Alaska Highway
Whitehouse
Yukon River

Legend

- Control Structure
- Powerhouse
- Watercourses
- Regulated Flow
- Auxiliary Spillway Channel
- Ditch
- Highway
- Secondary roads
- Trail
- Wetland

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km
0 0.9 1.8 2.7

1:60,000

UTM Zone 8N, NAD 83

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Lighting up the North
Yukon Electrical
An ATCO Company

Fish Lake Hydro System Facilities Layout

May 2012
Project 60247901

AECOM

Figure 2-1

Map Document: W:\GIS\Small Projects\Y2010\60119310-Fish Lake Relicensing\MXD\FINAL Figures 2010\FIG1-2-2010-11-04_Hydro_System_Facilities_layout_60119310_sm.mxd

LE-YECL-17

Reference: Section 13 Business Cases, Business Case #3

Request:

(a) Page 3 of 4: please confirm that the total of $1,474,000 is still the anticipated installed cost of the CUL 258 diesel replacement.

Response:

(a) Confirmed.

LE-YECL-18

Reference: Section 13 Business Cases, Business Case #6

Request:

(a) Page 3 of 4: please provide information on the northern utility that uses this technology – utility name, location of unit, generating capacity of unit, and date of conversion.

Response:

(a) The technical driver outlined in the business case notes that the technology is now ready to be demonstrated by a utility for power generation in Northern Canada. The Watson Lake Bi-Fuel Project is understood to be the first of its kind for a utility in Northern Canada.

For additional information please refer to the response to information request YUB-YECL-42(e).

LE-YECL-19

Reference: Section 13 Business Cases, Business Case #8

Request:

(a) Diesel fuel landed in Old Crow is expected to cost in excess of $2.18 per litre during the test period. Please list the design features of the proposed new plant and control system that would accommodate other new electrical energy sources with minimal disruption to the plant.

(b) Is there any non-plant use of the residual heat for community buildings? If not why not?

Response:

(a) The new Old Crow Plant facility will have a modern Programmable Logic Controller (PLC) control system (Please refer to Business Case #8). This new PLC will allow Yukon Electrical to integrate new electrical energy sources to the distribution system that our present PLC control system cannot.

(b) The community has approached Yukon Electrical in the past for us to supply waste heat. We have offered them the same contract and similar physical set up to that which exists in Watson Lake. To date the community has not pursued this further.

LE-YECL-20

Reference: Section 13 Business Cases, Business Case #11

Request:

(a) What is the capacity of the proposed new generator?

Response:

(a) The capacity of the proposed new generator is 300kW.

LE-YECL-21

Reference: Section 13 Business Cases, Business Case #12

Request:

(a) Please confirm that the $3 million capital cost for the proposed 2MW generator is the complete installed costs incorporating all features described in "Project Description" on page 1.

Response:

(a) Confirmed. Please refer to YUB-YECL-46(h) for a breakdown of the $3 million.

LE-YECL-22

Reference: Section 13 Business Cases, Business Case #26

Request:

(a) The project description indicates that HPS rather than LED street lights will be used. This goes contrary to the spirit of the DSM program that YECL and Yukon Energy are seeking Board approval for. Please justify in detail why YECL should not be leading by example by installing more energy efficient LED street lighting?

Response:

(a) When this subdivision was designed, LED lights were not a proven option that Yukon Electrical could offer. During the next stages, this is an option for the areas with 100W HPS cobra head lights. This will be a decision that the developer will have to make.

Please refer to LE-YECL-13 for an explanation as to the approach Yukon Electrical is taking with respect to the installation of LED streetlights in the Yukon.

LE-YECL-23

Reference: Section 13 Business Cases, Business Case #27

Request:

(a) Page 4 of 7: what are the human and overall error rates on present meter readings?

(b) What are the human and overall error rates on Northland Utilities Limited (Yellowknife) AMR meters?

(c) Are the new AMR meters "smart meters" that can communicate with other customer facilities?

(d) Will they be able to read water meters?

(e) Will the new AMR meters have the capability of remote connects or disconnects either built in or as an add-on option?

(f) Will the new AMR meters have the capability of remotely turning on or off specific customer appliances (e.g. water heaters and electric thermal storage units) either built in or as an add-on option?

Response:

(a) The current human and overall error rates on manual meter readings are 0.746% for the approximately 14,000 meters in the proposed AMR conversion project area.

(b) The human and overall error rates for Northland Utilities Limited (Yellowknife) AMR meters in the first quarter of 2013 were 0.44%.

(c) The AMR meters that Yukon Electrical has proposed to install cannot communicate with customer facilities. However, there is an option available for TWACS meters for a Load Control Transponder that remotely controls deferrable customer loads.

(d) Yes, they are compatible.

(e) This option is available as an add-on; however, Yukon Electrical is not pursuing this option at this time.

(f) The AMR meters will not have this option when the project is implemented. However, there are add-on devices available to work with TWACS meters that will remotely turn on and off customer appliances. Additional costs would be required to procure and install the device and to configure the AMR system to operate the device.

LE-YECL-24

Reference: Section 13 Business Cases, Business Case #30

Request:

(a) Please confirm that the DSM plan is a joint YECL – Yukon Energy plan that will be supported and implemented by both utilities.

(b) Please confirm that it will be a separate joint YECL – Yukon Energy witness panel that will be available for cross-examination on the DSM plan.

(c) Page 3 of 7: "*The plan was developed by the utilities in collaboration with interveners, Yukon NGOs, community leaders, First Nation Governments and the general public*"

(i) Did any party other than the utilities have any role other than to provide input to the utilities and their DSM consultants?
(ii) Did any party other than the utilities have final decision making authority as to the content and detail of the final DSM plan?
(iii) Did any of parties included in the list above indicate to the utilities at any time that they wished to see a more aggressive DSM plan?

(d) Page 7 of 7: Please confirm that the utilities were ordered by the Board to work together to develop DSM policies.

Response:

(a) Yes, the DSM plan is a joint plan and will be implemented jointly by both utilities.

(b) The utilities are supportive of a separate panel to examine the DSM Plan.

(c) (i) The Yukon government, through the Energy Solutions Centre (ESC), provided input through the Conservation Potential Review phase of the plan development. ESC was also a member of the DSM Working Group and DSM Steering Committee.

(ii) No party other than the utilities had final decision making authority as to the content and detail of the final DSM Plan.

(iii) Input of that nature was not recorded.

(d) Yes, the utilities were ordered by the Board to work together to develop the DSM plan under Board Orders 2009-2, 2009-8, 2010-13.

LE-YECL-25

Reference: Section 13 Business Cases

Request:

There are a number of business cases presented that involve reducing electrical loads on power lines by shifting customers to different lines, increasing voltages of lines/distribution systems, and bringing new supply lines into service. Please catalogue all of these into one table and provide the anticipated reduction in line losses individually and cumulatively.

Response:

Please refer to LE-YECL-25 Attachment 1 for a list of business cases that contribute to improving system efficiencies.

The projects listed in LE-YECL-25 Attachment 1 all contribute to improved line losses; however, in the context of the system-wide energy losses, the percent improvement is negligible.

Yukon Electrical is confident that its projects result in system efficiencies. Yukon Electrical's sales in MWh have grown by 8.2% from 2008 to 2012 (from 292,647 MWh to 316,575 MWh). The associated increase in load would normally be expected to increase losses. However, Yukon Electrical's losses over the same period have actually remained flat, as shown on line 4 of Schedule 3.2 in the Application. The projects listed in LE-YECL-25 Attachment 1 contribute to the flat trend.

The Yukon Electrical Company Limited
Projects That Impact System Efficiencies

Business Case	Description	System Efficiencies
18	Hillcrest Subdivision Conversion	Distribution line voltage doubled and larger conductor reduce line losses
21	Crestview to Mayo Road Corner Double Circuit	New and replacement distribution line built with large conductor
23	Whitehorse 5L628 and New 34.5kV Build	New and replacement distribution line built with large conductor
24	Downtown Whitehorse 25kV Conversion	Distribution line voltage doubled which will reduce line losses
25	Takhini/Marwell 4L315 Upgrade to 266 ACSR	Replace existing conductor with larger conductor reduces losses

LE-YECL-26

Reference: Section 13 Business Cases, Page 7: 4.2 Yukon Electrical Company Limited (YECL)

Request:

(a) "... *Yukon Electrical will develop and implement ... which meet the economic thresholds ... , as well as Yukon Electrical's mandate*." Please describe YECL's 'mandate' referred to here, and where it originates.

Response:

(a) Yukon Electrical's mandate is to deliver high value to its customers through the provision of safe, reliable, innovative and cost effective electric service.

LE-YECL-27

Reference: Section 13 Business Cases, Page 9 The Yukon five year DSM plan description starts in section 5.

Request:

(a) Please describe the programs each utility has undertaken internally to reduce own building or system wide electrical energy consumption (such as transformer loss reduction).

(b) Have any specific peak shaving program components been undertaken in this five year DSM plan?

(c) Have any specific peak load shifting (from peak to off-peak) components such as water heater timers/controls or the promotion of electric-thermal storage units (to replace baseboard electric heaters) been undertaken in this five year DSM plan?

(d) Has the government given any indication that they would support an approach to regulating the sale of devices of certain design standards to reduce consumer phantom loads (of electronics in particular – e.g. charging transformers that do not turn off when their load is disconnected)?

Response:

(a) Yukon Electrical continues to make internal system efficiency improvements and to address opportunities to improve energy efficiency within its various facilities. System improvements include: the conversion of Hillcrest subdivision to a higher voltage to reduce losses; designing the large transformers at Whistle Bend and at the Shipyard substation to ensure impedances are optimized to reduce internal losses; the current plans for building envelope improvements for the downtown office; insulation upgrades implemented in various plants; and air handling balancing and HVAC replacement in the service complex building. These improvements are outside the scope of the joint DSM plan.

Yukon Energy has completed some additional internal efficiency projects, pilot projects and public education initiatives, these activities along with the joint utility initiatives are outlined in section 5.3.1.5 of Yukon Energy's

2012-2013 General Rate Application and Yukon Energy's IR response YUB-YEC-46(d) Attachment 1. These activities are not part of the joint DSM plan. Costs associated with Yukon Energy's activities outside the joint DSM plan are not part of this application.

(b) There has been no specific peak shaving program components undertaken in the joint DSM plan.

(c) There has been no specific peak load shifting program component undertaken in the joint DSM plan.

(d) No, the government has not given any indication of support to an approach that would regulate the sale of certain devices.

UCG-YECL-1

Reference: May 27, 2013 Application, page 1-1

Request:

(a) Please provide a full explanation of how an application filed May 27, 2013 requesting approval of a revenue requirement effective January 1, 2013 should not be treated as an application requesting / endorsing rate retroactivity.

(b) Please provide examples of decisions by regulators in other jurisdictions which allow utilities to fully recover a full test year revenue requirement despite applying for that recovery during the test year.

(c) Please provide examples of decisions by regulators in other jurisdictions which denied utilities from recovering the full test year revenue requirement in a late filing situation similar to what has happened with YECL's current application.

Response:

(a) In light of s. 29(b) of the Yukon Territory's *Public Utilities Act* (the "PUA"), a clear exception to the principle against retroactive ratemaking, Yukon Electrical's application for approval of a revenue requirement effective January 1, 2013 does not request or endorse rate retroactivity. Section 29 of the PUA expressly permits the Board to approve a revenue requirement for the whole year in which a proceeding is initiated. It provides as follows:

> **29** In setting rates that a public utility is permitted to charge, (a) the board may consider the revenues and costs of the public utility in the financial year in which the proceedings for setting the rates and charges began or in any period immediately following, without considering the allocation of those revenues and costs to any part of that period;
>
> (b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable;

> (c) the board may give effect to any part of any excess revenue received or deficiency incurred after the commencement of the proceeding as the board determines has been due to undue delay in the hearing and determining of the matter; and
>
> (d) the board shall by order approve the method by which and the period during which any excess revenue received or deficiency incurred is to be used or dealt with. *R.S., c.143, s.29.*

Yukon Electrical filed its Application on May 27, 2013 in accordance with the PUA and in a manner that results in significant regulatory efficiencies that make it just and reasonable for the Board to exercise its discretion under Section 29(b) of the PUA to allow Yukon Electrical to recover its revenue deficiency for the whole of 2013. Please refer to Yukon Electrical's response to WL-YECL-1 for further information respecting the rationale for, and regulatory efficiencies achieved by, Yukon Electrical's delayed filing.

Additionally, Yukon Electrical's Application requests approval and recovery of a revenue requirement and revenue requirement shortfall for calendar year 2013 consistent with the following recent applications, which were filed subsequent to the start of the test period but approved by the YUB for recovery effective as at January 1 of the year in which they were filed:

- Yukon Electrical 2008/2009 GRA – filed April 30, 2008 (approved for recovery as at January 1, 2008);
- Yukon Energy 2008/2009 GRA – filed October 6, 2008 (approved for recovery as at January 1, 2008); and
- Yukon Energy 2012/2013 GRA – filed April 27, 2012 (approved for recovery as at January 1, 2012).

(b) Yukon Electrical is aware of the following examples of decisions by regulators in other jurisdictions that allowed utilities to fully recover a full test year revenue requirement despite applying for that recovery during the test year:

- Northland (NWT) Limited 2005-06 GRA – filed July 4, 2005;
- Northwest Territories Power Corporation 2006/2008 GRA – filed November 24, 2006;

- EPCOR Distribution & Transmission Inc. 2007-2009 Distribution Tariff and Transmission Facility Owners Tariff – filed February 1, 2008;

- Northland (Yellowknife) Utilities Limited 2008-2010 GRA – filed February 8, 2008; and

- Northland (NWT) Utilities Limited 2008-2010 GRA – filed February 8, 2008.

(c) Yukon Electrical is not aware of any examples of decisions by regulators in other jurisdictions which denied utilities from recovering the full test year revenue requirement in a filing situation similar to what has happened with Yukon Electrical's current application. While Yukon Electrical is aware of two decisions of the Northwest Territories Public Utilities Board ("NWTPUB") in which the Board denied interim rate applications filed by Northland (Yellowknife) and Northland (NWT) in April of 2011 seeking interim rates effective January 1, 2011, Yukon Electrical does not consider such decisions to be "similar to what has happened with Yukon Electrical's current application. Firstly, the within application is not one for interim rates. Additionally, the circumstances surrounding Yukon Electrical's delayed filing are not similar to those of the Northland filings. Finally, and perhaps most importantly, the referenced decisions of the NWTPUB were issued after prior notice had been provided by the NWTPUB to Northland (Yellowknife) and Northland (NWT) that the NWTPUB would be changing its prior practice of allowing interim rate applications effective of the first day in the year in which they are filed.

UCG-YECL-2

Reference: May 27, 2013 Application

Request:

(a) Please provide details of all stakeholder consultations conducted by YECL during development of this application prior to submitting it to the YUB.

(b) Please provide documentation related to issues discussed during these consultations and a list of all parties involved.

(c) Please confirm how and when the leadership / owners of YECL approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

Response:

(a) Development of this application required significant consultation to determine all cost and revenues on a historic, actual and forecast basis with respect to the following areas:

- Sales and revenue.

- Determination of customer counts and electricity usage as determined by discussion with customers, consultants, suppliers, communities and local developers. Yukon Electrical is intimately involved in development, design and construction related to new customers and projects. As such, Yukon Electrical is in communication with municipal and territorial governments, First Nations, communities, builders, manufacturers, suppliers, property managers, etc. Additionally, a significant level of effort has gone into the Conservation Potential Review and Demand Side Management initiative that has included a thorough consultation process with an extensive representation of stakeholders to further understand customer needs and technology options. Please refer to UCG-YECL-128(a) for additional detail.

- Purchase power in consultation with Yukon Energy to forecast Yukon Electrical costs related to securing wholesale electricity and to review system projects requirements.

- Fuel costs forecasts based on load projections for each diesel community serviced by Yukon Electrical as well as consultation with Yukon Energy Corporation related to diesel fuel for Yukon Electrical on-grid generating requirements. Consultation is required for service providers to supply Yukon Electrical generating facilities with fuel by road and by air access.

- Production costs and capital costs for hydro generation including consultation related to Fish Lake hydro water licence involving the Yukon Government, Yukon Water Board, First Nations, environmental consultants, lawyers, stakeholders, landowners, contractors, suppliers, designers, equipment providers and contractors.

- Operations and maintenance forecasts.

    (i) Labour costs consultation including employees, labour associations, human resource groups, ATCO Electric, training and safety, pension and benefits fund managers and accounting firms.

    (ii) A forecast for Non-labour areas is developed to determine on-going operational and administrative activities. Areas of consultation include affiliate companies, insurance companies, accountants, auditors, brushing contractors, other contractors, numerous material and service providers. Yukon Electrical also consults on its anticipated operating and maintenance costs for new projects.

- Capital additions for electrical system upgrades and additions as well as for property and other equipment are determined based on forecasts to meet customer needs. The diversity of projects involves a wide variety of stakeholders. In addition to the aspects of determining the need for projects and participants involved in consultation to compile data for the following areas; study work, design, regulatory approvals, permitting, construction, commissioning and on-going operations and maintenance, specialized expertise is also required based on individual project requirements.

Yukon Electrical met with the City of Whitehorse Infrastructure and Development groups to determine the applicability of AMR technology for use with city water meter requirements.

Yukon Electrical reviewed its plan for the Carcross Stand-by Generator with Yukon Energy and provided an update on the project to the Yukon Government.

Advancement of the Watson Lake Bi-fuel project involved meetings with the Town Council, public open houses including site tours of the power station, discussion with local First Nations, presentation to the Association of Yukon Communities, participation in the YESAA approval process, meetings and presentation to Yukon Government departments and Ministers, consultation with LNG experts in dealing with the transport of LNG that also assisted with developing the Canadian Standards Association standard for storage and handling of LNG. Consulting was also carried out with emergency response planners, responders and fire department professionals.

The Fish Lake hydro project involved extensive dialogue in addition to that related to the water licence renewal. Yukon Electrical has provided Yukon Energy with updates of the return to service schedule for unit 1 and discussed plans with the City of Whitehorse. It has met with First Nations and other stakeholders regarding the renewal project implementation as well as the on-going maintenance and operating requirements related to the eco-system.

Regarding communication with the Yukon Government and other agencies, Yukon Electrical relied on published materials from the Government and information through media (TV, newspapers). For the published material, please refer to the Yukon Government's latest economic projection for 2012 and 2013 YUB-YECL-56 Attachment 1.

(b) For information related to economic projections please refer to YUB-YECL-56. Please also refer to YUB-YECL-2 Attachment 1 for the Canada Mortgage and Housing Corporation Northern Housing Report, released in 2013.

Yukon Electrical attends Development Review Committee meetings on a monthly basis with numerous participants such as the City of Whitehorse, Kwanlin Dun First Nation, Ta'an Kwachan Council, Northwestel and Yukon Government. A copy of the capital planning forecasts for the City of Whitehorse is included as UCG-YECL-2 Attachment 2. A copy of the

capital planning forecast for the Yukon Government is included as UCG-YECL-2 Attachment 3.

Yukon Electrical has participated in Association of Yukon Communities AGM meetings.

(c) Approval to file Yukon Electrical's GRA was received on Saturday, May 25, 2013 with the Application being filed shortly thereafter on Monday, May 27, 2013. While Yukon Electrical had targeted a filing date of late April similar to its 2008-2009 GRA as well as Yukon Energy's 2012-2013 GRA, Yukon Electrical was aware that a decision from BCUC on its GCOC was due shortly. Given the Board's previous direction to link Yukon Electrical's utility return to another regulatory jurisdiction, a decision was made by Yukon Electrical to wait for and incorporate the impact of the May 10, 2013 BCUC GCOC Order G-75-13.

HOUSING MARKET INFORMATION

NORTHERN HOUSING REPORT

CANADA MORTGAGE AND HOUSING CORPORATION

Date Released: 2013

As a component of its product suite, CMHC Market Analysis produces an annual Northern Housing Report. This report focuses on the new home construction market, existing home market, and rental markets in Whitehorse, Yellowknife, and Iqaluit.

Whitehorse

Economy

Following a 6.5 per cent expansion in 2011, real Gross Domestic Product (GDP) in the Yukon increased by 3.4 per cent in 2012. This represented one of the strongest growth rates in Canada. The Yukon economy will continue on the same trajectory this year, with growth expected in mineral production as well as construction of new developments. Economic growth in 2013 will continue to be supported by investments in key sectors such as mining.

The mining sector continues to be a driving force in the Yukon economy. Despite the decline in world prices for minerals, the economy continued to expand due to contributions from the service industry and production from the three existing mines. Exploration expenditures were estimated at $150 million for 2012, below 2011 levels but the third highest level on record. Due to increased production in certain mines, the value of Yukon's mineral production has grown for the seventh consecutive year to an estimated $450 million in 2012. Victoria Gold's Eagle Gold mine is also expected to begin construction this year and further boost the economy. Statistics Canada's latest survey of Private and Public Investment Intentions indicates that total investment in the Yukon is expected to increase 17 per cent from 2012 levels. Higher activity in the mining and construction industries will attract more workers to the labour market.

Yukon employment remained relatively steady in 2012 averaging 19,000 people employed, slightly lower than 2011's record high. In the first quarter of 2013, the labour force posted losses while employment levels also decreased on a year-over-year basis. The unemployment rate declined in the first quarter of 2013 to 6.9 per cent, down from the 8.3 per cent a year earlier. Over the remainder

Highlights

Whitehorse

- Residential construction in 2013 will slow from the previous year, with 60 single-detached starts and 180 multi-family starts.
- Existing home sales to moderate from heightened level in 2013.
- Average vacancy rate is forecast to remain low at 1.7 per cent.

Yellowknife

- Total housing starts will moderate to 120 units this year.
- Residential sales will slow in 2013.
- Rental apartment vacancies will rise, slowing growth in rents.

Iqaluit

- Nunavut reports strongest economic growth in 2012 among provinces and territories.
- The average two-bedroom rent for units surveyed was $2,377 in 2012 compared to $2,356 in 2011.
- The vacancy rate in non-social housing units was 2.7 per cent in 2012, up from 1.4 per cent in 2011.

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of 2013, the labour market will be supported by investments in mining development and production, as well as construction.

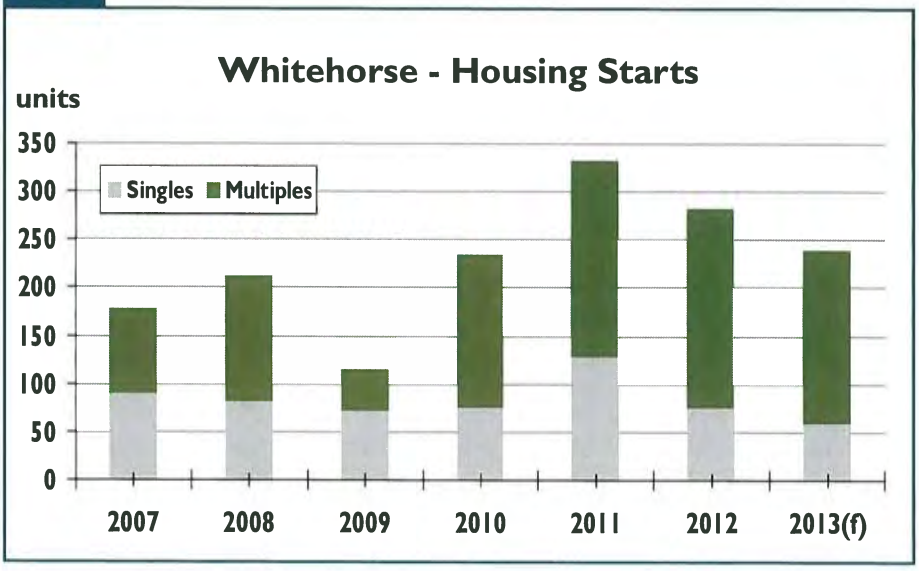
Net migration to the Yukon remained positive in 2012 totalling 444 people. As this represents a reduction from 617 net migrants in 2011, housing demand will slow somewhat this year. Supported by net migration and natural increase, the total population in the Yukon in 2012 reached 36,304 people, up 1.4 per cent from 35,800 in the previous year. The majority of the people in the Yukon reside in Whitehorse, representing 76 per cent of the territory's population. The Whitehorse population rose 1.8 per cent year-over-year, totalling 27,678 persons at the end of 2012.

New Home Market

Housing starts in Whitehorse totalled 282 units in 2012, a 15 per cent reduction from 332 in 2011. Single-detached starts declined by 42 per cent from the previous year, recording 75 starts in 2012. Multi-family starts, which include semi-detached units, rows, and apartment units, increased modestly by two per cent from 203 starts in 2011 to 207 starts in 2012. Row units accounted for the largest share of multi-family starts in 2012 at 117 units. Semi-detached and apartment units totalled 4 and 86 units, respectively, in 2012.

The availability of serviced lots in Whitehorse has improved compared to the previous year. With the implementation of the City of Whitehorse's Official Community Plan (OCP), land is being released and development has started in several new neighbourhoods. The largest new neighbourhood is the Whistle

Figure 1



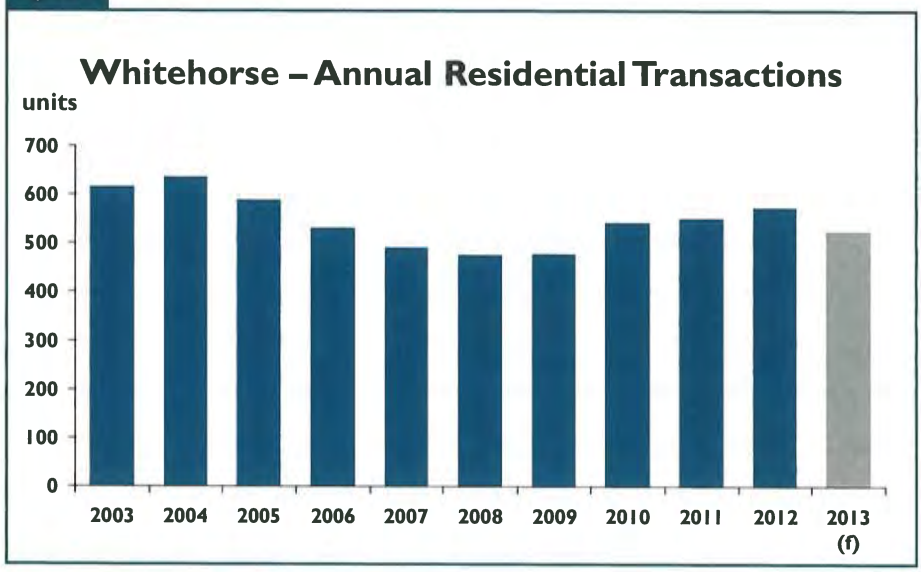
Source: CMHC, CMHC Forecast (f)

Bend project, anticipated to host 3,900 housing units and accommodate approximately 8,000 residents once complete. Phase 1 and 2 are currently under construction with lot sales beginning in 2012 and continuing into 2013. Phase 1 is expected to have 93 single-detached lots, 8 semi-detached lots, 9 multi-family lots to accommodate rows and apartments, and one commercial lot.

In the first quarter of 2013, four single-detached units have been started within the City of Whitehorse compared to seven in the previous year. With the supply of new homes listed in the existing home market rising and prices levelling off, it is expected that starts this year will be lower than last year. Further, due to slower economic growth fewer people are migrating to the area. These factors, combined with heightened competition from multi-family housing, will contribute to lower single-detached starts than 2012. By year-end, single-detached starts are expected to total 60 units.

The elevated level of multi-family production in 2012 is expected to moderate in 2013. The increase in multi-family construction last year falls in line with the sustainability directives of the 2010 OCP, in which the City of Whitehorse is actively supporting multi-family housing as an affordable alternative to single-detached homes. Many first time homebuyers as well as baby boomers who are looking to downsize are turning to multi-family housing. Further, with low mortgage rates and a tight rental market, multi-family housing is seen as a viable alternative to renting. However, with the elevated level of starts in 2012, many of these units will be entering inventory and increasing overall supply levels in Whitehorse. Given this and the slow-down in migration, multi-family starts are expected to decline slightly in 2013, totalling 180 units. Despite the reduction, this will still be elevated by historical standards.

Figure 2



Source: Yukon Bureau of Statistics, CMHC Forecast (f)

Real Estate Transactions

According to the Yukon Bureau of Statistics' quarterly Real Estate Survey, residential real estate transactions in Whitehorse, excluding those 'not-at-arm's-length', increased four per cent in 2012 to 574 units. The increase was attributed to the record high sales of condominiums which reached 224 sales in 2012, up 40 per cent from 2011. This continues to be a popular alternative for first time home buyers who are seeking a lower priced option to a single-detached home. Both single and semi-detached transactions finished the year below 2011 levels at 261 and 61 units, respectively.

The Yukon Housing Corporation introduced the Down Payment Assistance Program in 2013 to assist clients who could otherwise not afford home ownership. The program offers Yukon residents within a certain income range access to bank financing to purchase a home, with a low interest deferred loan of up to five per cent of the home's purchase price. This program will allow more potential home owners to enter into the market where they might not have been able to before. It is expected that the majority of applicants to this program will enter into the lower end price ranges and help support growth in condominium sales this year.

Condominiums will continue to be in high demand from first-time home buyers and existing home owners planning to downsize. Despite this, the overall resale market is expected to moderate in 2013 due to several factors. Growing inventory levels in Whitehorse has created elevated competition in the resale market. With active listings rising, days on the market is also getting longer. Many newly constructed units are also entering the resale market, providing potential buyers additional selection.

Total MLS® sales for the first quarter of 2013 were unchanged from the previous year at 67 transactions. On the supply side, active listings exhibited an increase during the first quarter, averaging 226 units per month compared to an average of 149 units the previous year. Overall, resale transactions are anticipated to reach 525 units in 2013, a decrease of 8.5 per cent from 2012.

The average price for all types of housing in 2012 was $358,978, down one per cent from 2011. The decline was largely attributed to a higher number of condominium units sold, which are generally priced lower than single and semi-detached units. Condominium prices averaged $301,332 in 2012, up 23.7 per cent from a year earlier and accounted for 39 per cent of total sales. On the other hand, the average price for single and semi-detached homes declined from the previous year. Single-detached prices in 2012 averaged $428,110, down 1.5 per cent from 2011, while semi-detached units averaged $323,146, down two per cent.

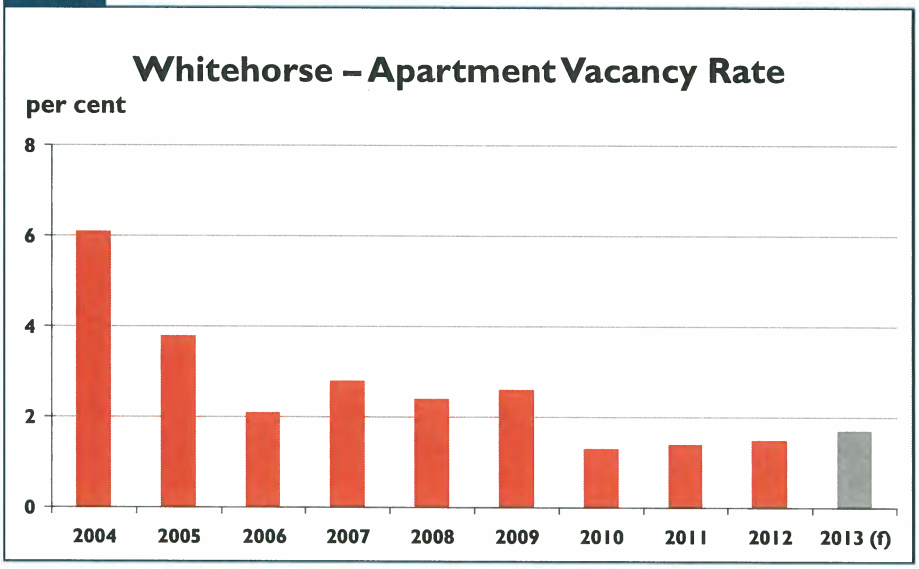
After a slight decline in price in 2012, elevated levels of supply are expected to continue to inhibit resale price growth this year. The average MLS® price declined by less than one per cent during the first quarter of 2013. Condominium sales accounted for a large portion of overall sales so far this year, and will continue to impact the average price in 2013. Overall, Whitehorse's average resale price is forecast to increase one per cent to an average of $362,500 in 2013.

Rental Market

Demand for rental units in Whitehorse continues to be high. The average apartment vacancy rate in Whitehorse increased modestly in March 2013 to 1.5 per cent, compared to 1.3 per cent the previous year. This represents 15 vacant units out of 1,015 units in the apartment rental universe. It is expected that with the increase in apartment condominium starts in 2012, some of these units will eventually enter the secondary rental market and compete with existing units. Given this and the reduction in migration, CMHC expects the vacancy rate to increase slightly to 1.7 per cent by December.

With continued low vacancies, the average rent for a two-bedroom unit in Whitehorse increased to $943 in March 2013, up from $896 a year earlier. After increasing $57 in 2012, CMHC forecasts the two-bedroom rental rate to increase $44 to an average of $950 in 2013.

Figure 3



Source: Yukon Bureau of Statistics Q4 Yukon Rent Survey, CMHC Forecast (f)

Whitehorse Forecast Summary June 2013

	2010	2011	2012	Yr/Yr Change	2013(F)	Yr/Yr Change
New Home Market						
Total Starts (units)	234	332	282	-15.1%	240	-14.9%
Single-Detached Starts	75	129	75	-41.9%	60	-20.0%
Multi-Family Starts	159	203	207	2.0%	180	-13.0%
Real Estate Transactions*						
Residential sales	543	552	574	4.0%	525	-8.5%
Average price ($)	323,918	362,058	358,978	-0.9%	362,500	1.0%
Rental Market(Q4 data)**						
Apartment Vacancy Rate (%)	1.3%	1.4%	1.5%		1.7%	
Average Two-Bedroom Apartment Rent ($)	810	849	906		950	

*MLS®+Private(source: YBS, CMHC Forecast)
** source: YBS, CMHC Forecast

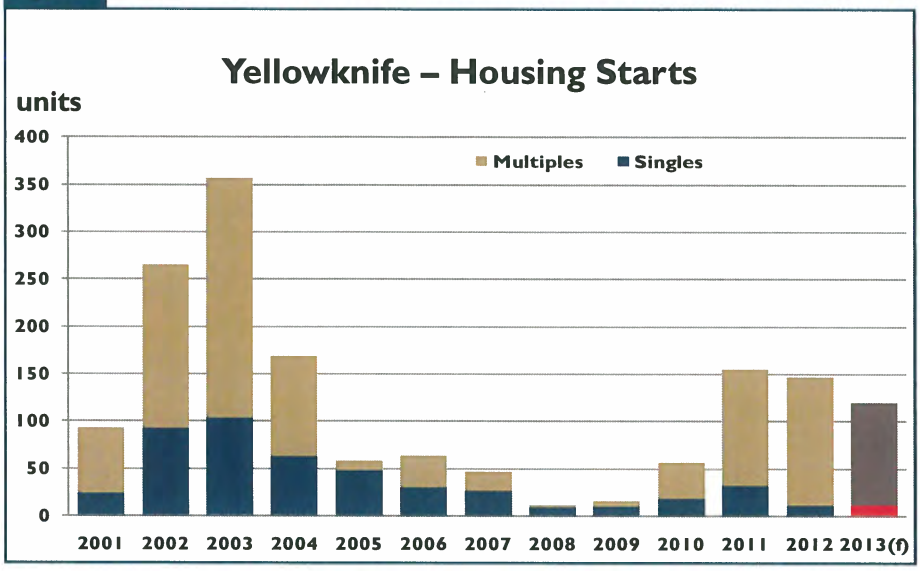
Yellowknife

Economy

Following a 4.9 per cent contraction in real Gross Domestic Product (GDP) in 2011, the Northwest Territories' (NWT) economy grew by 1.9 per cent in 2012. The chief contributors to NWT's economic growth last year were gains in mining output and oil and gas extraction, and advances in construction. Mining output and oil and gas extraction accounted for 29 per cent of NWT's real GDP in 2012. A 21 per cent gain in oil and gas extraction and 13 per cent advance in support activities offset a 4.1 per cent decline in diamond output. Recent exploration activity in the Sahtu Region prompted the rise in support activities for oil and gas extraction. Diamond production, on the other hand, declined in 2012 due to reduced carat production, lower diamond prices, the closing of Diavik's open pit mine, and the extraction of lower-grade diamonds at Ekati. The extension of work on the Deh Cho Bridge last year contributed to a 10 per cent gain in construction.

The 21 per cent gain in capital spending in 2012 also fuelled NWT's economic growth. Nearly 80 per cent of NWT's capital investment was made by the private sector last year, with private capital spending rising 27 per cent year-over-year. Meanwhile, NWT's government capital investment advanced two per cent in 2012. Both the Conference Board of Canada and the Government of NWT forecast real GDP growth of 0.2 per cent for 2013. Expected losses in diamond production and declining capital spending will account for the subdued economic growth in 2013. The projected decline in diamond production is due to weaker international demand, lower output at Diavik and Ekati, and the difficulty for mines to recruit new labour. Declines in diamond production and capital spending are forecast to be partly offset by some gains in household and government spending.

Figure 1



Source: CMHC, CMHC Forecast (f)

NWT employment in 2012 averaged 22,700 persons, unchanged from 2011 and 700 persons below the 2007 pre-recession peak of 23,400. In 2012, the labour force participation rate was 76.9 per cent, an increase from 76.3 per cent in 2011 but below the 2007 participation rate of 78.2 per cent. The increase in the participation rate led to a corresponding increase in the unemployment rate from 7.3 per cent in 2011 to 8.1 per cent in 2012, as more people entered the labour market than were able to secure employment.

Job creation is expected for 2013. The 400 new jobs forecast by the Conference Board for this year are in line with the expectation of increased construction activity and the development of several new mines. Provided that they receive regulatory approvals, up to seven new mines could begin production in the next five years. Oil and gas exploration companies have already committed more than $600 million for exploration activities in the Sahtu region. The employment expansion this year will also be supported by government plans to invest $139 million in public infrastructure and housing, and $7 million in the Mackenzie Valley Fibre Optic Link project.

The population in NWT has slowly declined in the last couple of years. In the fourth quarter of 2012, the population was at 43,313, slightly down from 43,866 in 2011. Migratory movements out of NWT have held back population growth in the last several years. Net migration recorded a net loss of 821 migrants in 2012 due to interprovincial migration, while international migration was positive. As such, demand for housing will continue to be driven by factors such as employment and income growth, rather than net migration.

New Home Market

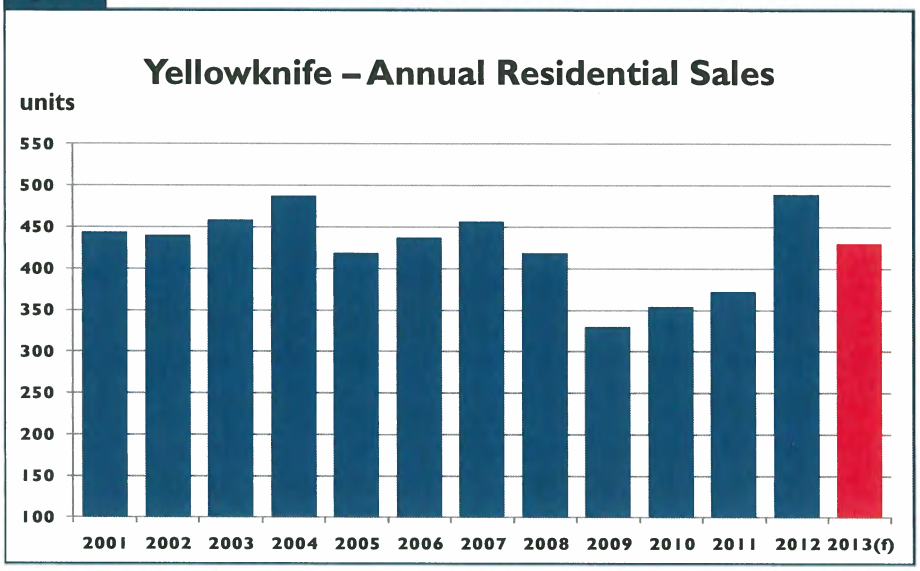
With incomes remaining high and mortgage rates low, residential construction remained elevated in Yellowknife last year. Following 155 total housing starts in 2011, 147 new homes broke ground in Yellowknife in 2012, the second highest in eight years. Multiple construction dominated last year's construction activity with multi-family starts rising 10 per cent year-over-year to 135 units, the highest since 2004. The market demonstrated a strong preference for condominiums. As such, builders reacted by reducing single-detached construction to 12 units and raising condominium starts to 94 units in 2012, the highest on record.

The expected job creation will provide support to residential construction this year, as will additional lot selection, stable mortgage payments, and elevated incomes. However, a declining population and heightened supply levels will prevent growth in starts in 2013. At the end of March 2013, there were 101 homes under construction in Yellowknife, up 10 per cent from the previous year. As such, builders this year will focus more on completing on-going projects rather than starting a sizeable amount of new ones. Multi-family construction, which includes semi-detached, row, and apartment units, is expected to reach 108 units in 2013. Construction of single-detached homes is forecast to reach 12 units this year, on par with 2012. Despite the reduction in overall construction, total housing starts will remain above the preceding 10-year average.

Resale Home Market

The 489 homes sold in 2012 marked the highest number of sales in 13 years and a 31 per cent gain over 2011. Residential sales are projected to moderate to 430 transactions in 2013, a 12 per cent reduction from 2012 but still the second highest in six years. Low mortgage rates, high rents, and elevated incomes will continue to support sales, although at a more subdued pace compared with 2012. For example, to the end of March 2013, monthly mortgage payments on an average condominium apartment were down four per cent year-over-year and below the two-bedroom average apartment rent, providing additional incentive to move into homeownership. Sitting currently at $89,475, annual income per employed is also supporting resale demand in Yellowknife.

Figure 2



Source: CMHC (MLS® & Private Sales), CMHC Forecast (f)

Heightened demand for housing contributed to a steady turnover in listings last year, which improved the supply/demand balance and supported price gains. The average sale price increased 3.4 per cent in 2012 to $387,900. Higher demand and a compositional shift toward the highest price range supported price growth last year. In 2012, 39 per cent of sales were above $400,000, surpassing 2011's comparable share of 32 per cent.

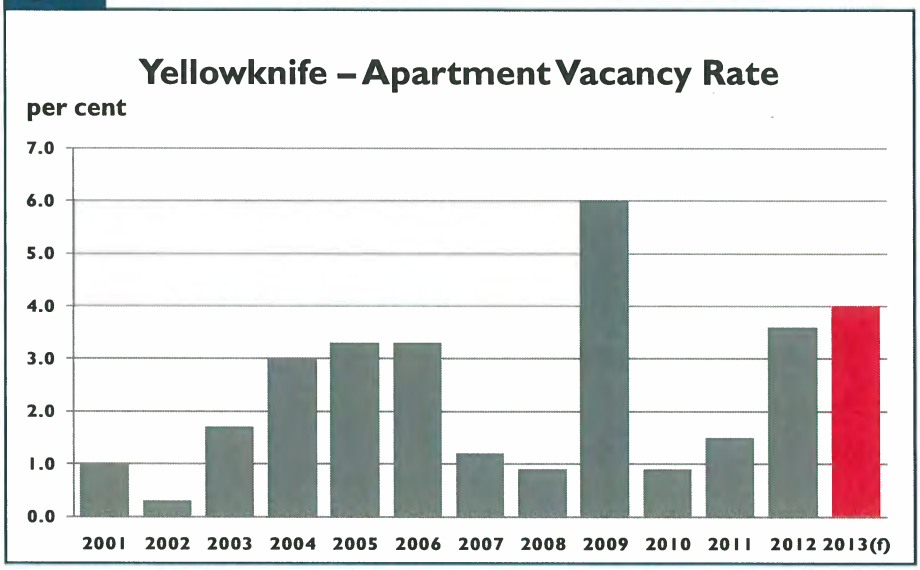
The average sale price is expected to rise to $398,000 in 2013, a 2.6 per cent year-over-year gain. Price growth will slow this year due to weakness in demand relative to supply levels. The 56 resale transactions that took place during the first quarter of 2013 were 51 per cent below the first three months of 2012. Meanwhile, new listings in the first quarter rose from 65 homes in 2012 to 76 units in 2013. As a result, the sales-to-new listings ratio (SNLR) in the first quarter was 74 per cent, down from 177 per cent a year earlier. Most of the gains in prices this year will be due to composition. For instance, to the end of March 2013, 30 per cent of sales were above $400,000 compared to a 22 per cent share one year earlier.

Rental Market

The increased outflow of migrants from the Northwest Territories to other jurisdictions, and tenants making the move to homeownership has

impacted rental demand in Yellowknife. The average apartment vacancy rate in Yellowknife increased from 1.5 per cent in October 2011 to 3.6 per cent in October 2012. Over the first nine months of 2012, 350 existing homes changed hands, up 11 per cent year-over-year. Meanwhile, 896 people left the Northwest Territories to other provinces on a net basis in the first three quarters of 2012, further contributing to the increase in vacancies. The average monthly rent for two-bedroom apartments in Yellowknife was $1,641 in October 2012 compared with $1,566 a year earlier.

Figure 3



Source: CMHC, CMHC Forecast (f)

Rental demand this year will be supported by job gains and elevated incomes. However, rental demand will not be strong enough to offset vacancies stemming from the movement into homeownership and low migration. With relatively stable monthly mortgage payments this year, some renters will move forward and buy an existing or new home. With rental units being freed as tenants move out, the average vacancy rate will slightly rise to 4.0 per cent in October 2013 from 3.6 per cent in October 2012. In the face of rising vacancies in 2013, landlords will likely slow the pace of rent increases. Average rents of two-bedroom apartments will rise to $1,675 in October 2013, up from $1,641 in October 2012.

Yellowknife Forecast Summary June 2013

	2010	2011	2012	Yr/Yr Change	2013(F)	Yr/Yr Change
New Home Market						
Total Starts (units)	57	155	147	-5.2%	120	-18.4%
Single-Detached Starts	19	32	12	-62.5%	12	0.0%
Multi-Family Starts	38	123	135	9.8%	108	-20.0%
Resale Market*						
Residential sales	354	372	489	31.5%	430	-12.1%
Res. resale price ($)	367,250	375,050	387,900	3.4%	398,000	2.6%
Rental Market (October Survey)**						
Apartment Vacancy Rate (%)	0.9%	1.5%	3.6%		4.0%	
Average Two-Bedroom Apartment Rent ($)	1,486	$1,566	$1,641		$1,675	

*MLS®+Private(source CMHC Forecast)
** source: CMHC, CMHC Forecast

Iqaluit

Economy

In 2012, Nunavut had the fastest growing economy among all provinces and territories in Canada. After increasing 4.8 per cent in 2011, real Gross Domestic Product expanded 4.3 per cent in 2012, more than doubling the national growth rate of 1.8 per cent. The economic growth experienced in 2012 was largely attributed to expansions in natural resource extraction and increased wholesale trade output. According to Statistics Canada, output in the mining and oil and gas extraction sector increased 25 per cent, while wholesale trade in 2012 increased by a similar margin. This growth, along with moderate gains in other sectors, more than offset the 19 per cent year-over-year reduction in the construction industry in 2012.

Higher investment intentions are expected to support economic growth for the year ahead. Private and public investment intentions for 2013 in Nunavut, as surveyed by Statistics Canada, revealed intentions of capital expenditure across all sectors of $1,079.5 million. This represents a gain of almost 18 per cent over estimations for last year. For mining and oil and gas extraction, spending intentions are expected to increase almost 28 per cent year-over-year to $736.3 million in 2013, up from $577.2 million in 2012. As spending in this sector accounts for a large proportion of total investment intentions in Nunavut, the increase will be a significant contributor to the territory's economic prosperity for 2013.

Consumer spending in 2012 continued to trend upward, supported by strong economic growth and higher average earnings in Nunavut. Following recent year-over-year annual increases between five and 11 per cent, retail trade grew by 2.5 per cent in 2012. In contrast, wholesale trade bounced back in 2012, expanding 52 per cent year-over-year after reporting a reduction of 26 per cent in 2011. Across all industries, average weekly earnings increased by seven per cent in 2012, compared to 2011. By year-end, average earnings was $906 in 2012, an increase of $62 per week from $844 one year prior. On a year-over-year basis, the largest gain in wages was recorded in the public administration sector where average weekly wages in 2012 increased by 14 per cent.

In 2012, Nunavut's population grew by 1.4 per cent to reach 34,028 persons, up from 33,563 persons in 2011. The rate of population growth was attributed to a strong rate of natural increase as the number of births exceeded deaths. Since forming in 1999, the territory has witnessed negative net migration almost every year with the exception of 2000, 2009, and 2010. Comparing 2011 and 2012, the number of net migrants leaving the territory declined by almost 20 per cent year-over-year to 144 persons, many of whom left for other provinces in the country. A slow employment expansion inhibited migration to the region. Across all industries, total employment in Nunavut remained relatively unchanged in 2012 compared to 2011. The only gain in employment was for part-time positions, which increased by 100 positions year-over-year.

New Home Construction

New home construction in Iqaluit moderated in 2012 with a lower level of residential investment and building permits issued compared to 2011. Two areas which saw developments in 2012 were the Road to Nowhere and Phase 3 of the Plateau subdivisions. Moving forward, further development is expected to take place in Phase 4 of the Plateau subdivision as well as in Apex where 16 new lots were released. More than half of the lots in Phase 3 began construction in 2011. In 2012, many of those developments were completed in the form of multi-family units.

There were approximately 65 multi-family completions in 2012 comprising

Iqaluit Total Residential Sales

	2009	2010	2011	2012
Residential Sales	37	43	60	63
Average Price	$349,168	$344,008	$335,456	$410,073
Median Price	$356,350	$369,000	$367,000	$411,421
Avg. Price Sq. foot	$220.00	$204.11	$237.00	$255.45

Source: CMHC

of two 12-plex apartment buildings, 33 row houses, and four duplexes, many of which are intended for rental purposes. In the Road to Nowhere subdivision, there was the completion of two four-storey apartment buildings with one containing 39 suites and the other, 40 suites. The structure containing 39 suites was built to replace the 29 unit building that was destroyed by fire in March 2010.

The five-year average for total permits issued within the territory was approximately 180 permits a year since 2007. However in 2012, the number of permits issued in Nunavut declined to 90 permits, down from the record high of 313 permits issued in 2011. The 90 permits were comprised of 13 single-detached dwellings, 74 multi-family units, and one conversion. This compared to 18 single-detached and 295 multi-family permits issued in 2011. With the reduction in permits, capital expenditure on housing was estimated to have declined by 32 per cent in 2012 compared to 2011. For 2013, according to Statistics Canada, capital expenditure intentions in the housing sector are expected to decrease to $64.4 million, representing a decline of 10 per cent from an estimated $71.6 million in 2012.

Residential Transactions

Economic growth has supported existing housing demand in Iqaluit. Transfers of residential real estate in Iqaluit totalled 84 units in 2012, a slight gain over 2011 when 81 transfers were recorded. The Iqaluit housing market is unique compared to most markets across Canada. Like many Nunavut communities, most of the land or lots in Iqaluit are owned either by the municipality or by the Inuit. The majority of lots are titled to the Municipal Corporation which issues Leasehold Titles for use. When the title of the lease is transferred, a price (either the cost of development or some consideration) is also determined.

Iqaluit Residential Sales by Type

2012	Single-detached	Condo/Row/Semi
Residential Sales	46	17
Average Price	$420,315	$382,359
Median Price	$414,500	$411,421
Ave. Price Sq. foot	$249.01	$276.74

Source:CMHC

Of the 84 transfers recorded in 2012, 21 were declared at nominal transactional values between $1 and $20. For the remaining 63 transactions, the sale values ranged between $169,000 and $700,000. Comparing 2012 with 2011, significant growth in the average price occurred as the range in sales values in 2011 was between $74,000 and $490,000. Excluding nominal transactions which would have a greater compositional impact, the average price of all residential transactions was $410,073 in 2012. This represented a 22 per cent increase from the average price of $335,456 in 2011. In addition to compositional impacts, rising demand for housing in Iqaluit has contributed to the year-over-year gain in average price. Similar to the average, the median price increased in 2012 compared to 2011. The median price of all transactions was $411,421 in 2012, up from $367,000 in 2011.

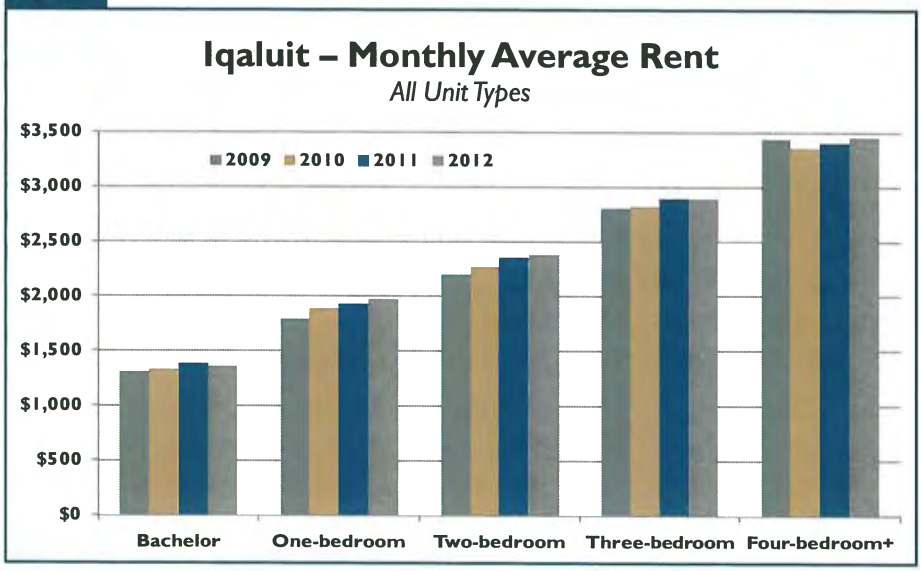
Of the 84 residential transactions recorded in 2012, 67 were single-detached units and the remaining 17 were multi-family. All of the 21 nominal transactions valued between $1 and $20 were for single-detached units. The range between sales values has changed considerably from 2011 to 2012 for both single-detached and multi-family units. For the remaining 46 single-detached units in 2012, sale values were recorded between $200,000 and $700,000, up from a range of $74,000 to $490,000 in 2011. For single-detached units, not including nominal transactions, the average price was $420,315 in 2012, while the median price was $414,500. There were 17 multi-family transactions ranging in value between $169,000 and $455,000 in 2012. The average price for multi-family units was $382,359, while the median price was $411,421.

Rental Market

According to the results of CMHC's annual rental survey in Iqaluit, the rental universe increased to 1,875 units in 2012, up from 1,809 units in 2011. Within the rental universe, 362 units were identified as social housing (public) units and were not included in the average rent calculations. The additions to the universe in 2012 were in the form of newly completed rental structures, many of which were in the Road to Nowhere subdivision and Phase III of the Plateau subdivision.

In 2012, vacancy rates experienced upward pressure for the second consecutive year. The vacancy rate in

Figure 1



Source: CMHC Survey (does not include public housing units)

2012 increased to 2.7 per cent from 1.4 per cent in 2011, within structures surveyed by CMHC, excluding social housing units. A large proportion of vacancies were found in newer rental buildings. Of the 1,513 non-social housing units surveyed, 41 were found vacant at the time of the 2012 survey and comprised mostly of two-bedroom units.

With higher vacancies, the average rent for all bedroom types was relatively stable at $2,335 in 2012, compared to an average rent in 2011 of $2,324. New units added to the rental universe were the primary contributor to the higher average rent as new units tend to command higher rental rates. The change in average rents between 2011 and 2012 was modest by historical standards at $11 per month.

Among bedroom types, the strongest gain in average rents was for four-bedroom suites. The average rental rate for four-bedroom suites increased $49 per month over the 2011 average, reaching $3,451 per month. Rental rates for both one- and two-bedroom suites also recorded year-over-year increases while three-bedroom average rents were relatively unchanged. In contrast, the monthly average rent for a bachelor suite in 2012 was $1,359, compared to $1,386 per month in 2011.

Rental Market Survey Methodology

The purpose of the CMHC survey was to identify residential accommodation in Iqaluit available for long-term rental and identify the current market rent on those units. The survey was conducted over a six-week period, from mid-November to year-end 2012. Our survey depends on the input of developers, building owners, two levels of government, and their respective housing officials. CMHC acknowledges their hard work and assistance in providing timely and accurate information.

Average Monthly Rent - by bedroom type
(excluding social housing)

	2011	2012	Yr/Yr Change
Bachelors	$1,386	$1,359	-$27
One-bedroom	$1,930	$1,971	$41
Two-bedroom	$2,356	$2,377	$21
Three-bedroom	$2,891	$2,892	$1
Four-bedroom+	$3,402	$3,451	$49
Total Average	$2,324	$2,335	$11

Source: CMHC

Rental Universe - 2012

Units	
Bachelors	63
One-bedroom	530
Two-bedroom	547
Three-bedroom	331
Four-bedroom	42
No BR Identified (Social)	362
Total	**1,875**

Source: CMHC

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- Housing Market Outlook, Major Centres
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- Housing Now, Canada
- Housing Now, Major Centres
- Housing Now, Regional
- Monthly Housing Statistics
- Northern Housing Outlook Report
- Preliminary Housing Start Data
- Rental Market Provincial Highlight Reports
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17-04-13

City Of Whitehorse

2013 - 2016 Capital Expenditure Program

All Years

	2013 Capital Budget	2014 Capital Budget	2015 Capital Budget	2016 Capital Budget	Total All Years
City Manager					
Approved					
100c00111 Organizational Review	70,000				70,000
Total Approved	70,000				70,000
Director, Infrastructure & Operations					
Approved					
120c00213 Fleet Management Strategy	40,000				40,000
Total Approved	40,000				40,000
Director, Development Services					
Approved					
130c00113 Energy Plan Implementation	20,000				20,000
Total Approved	20,000				20,000
Communications					
Approved					
201c00113 Press Conference Centre	12,000				12,000
Total Approved	12,000				12,000
Engineering					
Approved					
240c00209 Hillcrest Des/Recon		300,000			300,000
240c00213 Hillcrest Water Supply	800,000				800,000
240c00313 Range Road North BST	300,000				300,000
240c00410 Asphaltic Surface Overlay Program				1,000,000	1,000,000
240c00509 Robert Campbell Bridge Widening	1,700,000				1,700,000
240c00510 Hospital Road & Lewes Blv'd Intersection I	500,000				500,000
240c00709 Selkirk Well Development		1,240,000			1,240,000
240c00910 City-Wide Water Meters	30,000				30,000
240c01111 Range Road North Reconstruction	2,100,000				2,100,000
240c01410 Storm Sewer Upgrades				100,000	100,000
240c02010 Downtown Reconstruction - 6th Ave	200,000	2,500,000			2,700,000
240c02309 Asphalt Paths-Various Locations	300,000				300,000
240c02609 SCADA program	270,000	235,000	276,000	440,000	1,221,000
500c00509 Sidewalk Construction	300,000	150,000			450,000
Total Approved	6,500,000	4,425,000	276,000	1,540,000	12,741,000
Financial Services					
Approved					
260c00109 Office Furniture	50,000	50,000	50,000		150,000
260c00209 PSAB Compliance	55,000				55,000
Total Approved	105,000	50,000	50,000		205,000
Information Systems					
Approved					
300c00109 Computer Infrastructure	295,500	285,000	284,500	291,000	1,156,000
300c00110 Software Acquisition	120,000	75,000	70,000	115,000	380,000
300c00111 Software Licensing Renewals	286,000	353,000	363,000	293,000	1,295,000
300c00113 ERP Development	30,000	30,000	30,000	30,000	120,000
300c00212 Paperless Document Management	64,500	54,500	57,500	7,500	184,000
300c00213 Performance Management Software	30,000	1,500	1,500	1,500	34,500
300c00313 Budget Software Plan Request Module (FI	34,250	3,000	3,000	3,000	43,250
300c00409 Web Maintenance	20,000	20,000	20,000	20,000	80,000
300c00412 Transit:Handybus Onboard Scheduling/Ro	25,300	1,700	1,700	1,700	30,400
Total Approved	905,550	823,700	831,200	762,700	3,323,150
Maintenance					
Approved					
320c00110 One Ton Replacements	130,000	130,000	65,000	70,000	395,000
320c00111 Major Bus Repairs		75,000	75,000	75,000	225,000
320c00112 Packer- Whistle Bend		290,000			290,000
320c00212 Sweeper Whistle Bend		270,000			270,000
320c00313 20 foot Bob Cat Tilt Trailer	16,000				16,000
320c00413 Replacement Car	30,000				30,000
320c00510 P&R Equipment Replacement- Lawn Tract				35,000	35,000
320c00513 Compost Equipment	680,000	500,000			1,180,000

City Of Whitehorse

2013 - 2016 Capital Expenditure Program

All Years

	2013 Capital Budget	2014 Capital Budget	2015 Capital Budget	2016 Capital Budget	Total All Years
320c00610 Major Equipment Repairs	100,000				100,000
320c00612 Duct Cleaning City Buildings		125,000			125,000
320c00613 Five ton Truck				120,000	120,000
320c00812 Replacement Bucket Truck		140,000			140,000
320c01011 Overhead Door Replacement- Kulan Sateli	20,000				20,000
320c01112 Refinish Flexihall Flooring	75,000				75,000
320c01311 Pool Regrout- Tanks	75,000				75,000
320c01411 Whistle Bend Bus	450,000				450,000
320c01511 Loader - Whistle Bend	250,000				250,000
320c01611 Grader - Whistle Bend		290,000			290,000
320c01709 Pickups	250,000	250,000	200,000	200,000	900,000
320c01711 Dump Truck - Whistle Bend		290,000			290,000
320c01712 Environmental Assessments- Surplus Prop			100,000		100,000
320c01811 Vactor - Whistle Bend		460,000			460,000
320c01813 Kids Club Expansion CGC	80,000				80,000
320c02009 Grader Replacement	290,000				290,000
320c02109 Van Replacement	40,000	40,000	40,000		120,000
320c02113 1 Ton Pump Service Truck	75,000				75,000
320c02313 Tandem Axle Trailer			12,000		12,000
320c02410 Skid Steer Loader Purchase	40,000				40,000
320c02610 Fire Hall #2 Reno	73,000				73,000
320c02613 Solar Wall Bypass Design	35,000				35,000
320c02709 Radio and Location Equipment	40,000	40,000	35,000	30,000	145,000
320c02809 Purchase of Dump Trucks	290,000			160,000	450,000
320c02810 Track Hoe Purchase		275,000			275,000
320c03110 Loader Replacement				290,000	290,000
320c03810 Public Works- Pot Hole Patcher	100,000				100,000
Total Approved	3,139,000	3,175,000	527,000	980,000	7,821,000
Bylaw					
Approved					
400c00113 Trail Signage	10,000	10,000	10,000		30,000
400c00412 Auto Chalk			120,000		120,000
Total Approved	10,000	10,000	130,000		150,000
Fire Department					
Approved					
440c00113 EMO Communications Equipment	10,000				10,000
440c00209 SCBA replacement/upgrade	40,000	50,000	50,000	50,000	190,000
440c00210 Technical Rope Rescue	15,000	15,000	15,000	15,000	60,000
440c00211 Fire Service Master Plan	50,000				50,000
440c00309 Turnout Gear Replacement	30,000	35,000	35,000	35,000	135,000
440c00310 Thermal Imaging Cameras		17,000			17,000
440c00311 Pumper Replacement (second unit)		650,000			650,000
440c00510 Training Centre Improvements	45,000	25,000	25,000	25,000	120,000
440c00810 Pumper Replacement	650,000				650,000
Total Approved	840,000	792,000	125,000	125,000	1,882,000
Public Works					
Approved					
500c00109 Traffic Controllers Cabinet	40,000	40,000	40,000	40,000	160,000
500c00110 PW Small Equipment	96,000	40,000	58,000	45,000	239,000
500c00112 Carts - Whistle Bend	30,000	38,100			68,100
500c00113 Landfill Cell 5 Development	200,000				200,000
500c00209 Landfill Upgrades	50,000	45,000	25,000		120,000
500c00212 Landfill Fire Restoration	195,000				195,000
500c00213 Landfill Free Store and Redesign of Public	45,000				45,000
500c00313 Compost Operation Improvements		250,000			250,000
500c00409 Para Ramp Infills	30,000	30,000	30,000	30,000	120,000
500c00609 Guide Rail & Jersey Curb Replacement			60,000	60,000	120,000
500c00709 Unpaved Road Construction			60,000		60,000
500c01009 Snow Dump Development	15,000	30,000	15,000		60,000
Total Approved	701,000	473,100	288,000	175,000	1,637,100

City Of Whitehorse
2013 - 2016 Capital Expenditure Program
All Years

	2013 Capital Budget	2014 Capital Budget	2015 Capital Budget	2016 Capital Budget	Total All Years
Environment					
Approved					
600c00113 Transportation Demand Management Plai	70,000				70,000
Total Approved	70,000				70,000
Water and Sewer					
Approved					
650c00113 Trench Cage Extension	8,000				8,000
650c00209 Pumphouse & Recirculation	100,000	30,000	60,000	90,000	280,000
650c00213 Leak Detector and Line Tracer	32,000				32,000
650c00313 Portable Gas Detector Docking Station	12,000				12,000
650c00410 Small Lift Station Upgrades	206,000	70,000	140,000		416,000
650c00413 Marwell Lift Diesel Backup Pump Control I	60,000				60,000
650c01109 Water Well Rehab	50,000				50,000
650c01409 Hydrant Infill			45,000		45,000
Total Approved	468,000	100,000	245,000	90,000	903,000
Planning					
Approved					
720c00111 Residential Intensifications - Porter Creek		80,000			80,000
720c00113 Residential Intensifications - Riverdale		100,000			100,000
720c00213 Long Term Land Planning	200,000	100,000	100,000		400,000
720c00311 Porter Creek Extension ("D")	75,000				75,000
720c00413 Schwatka Lake Planning Study	30,000				30,000
720c00613 Marwell Planning Study		50,000			50,000
720c00711 Park Management Plans - OCP		50,000	50,000	50,000	150,000
720c00713 Whistle Bend Final Phases			500,000		500,000
720c00812 Range Road Planning Study	20,000				20,000
Total Approved	325,000	380,000	650,000	50,000	1,405,000
Parks and Rec.					
Approved					
740c00309 Playground Equipment Replacement	55,000	55,000	55,000	55,000	220,000
740c00409 Trail Plan Implementation	60,000	60,000	60,000	60,000	240,000
740c00609 Cemetery Expansion GMC		30,000	470,000		500,000
740c00610 Paved Trail Resurfacing - Parks	100,000		100,000		200,000
740c01009 Erosion Control	20,000		20,000		40,000
740c02810 Trees at Turf Park - Parks	50,000				50,000
740c03510 Parks Equipment - Parks	35,000	35,000	35,000	35,000	140,000
740c03810 Winter Lights - Parks			30,000		30,000
740c04210 Tree Grates - Parks	25,000	25,000			50,000
740c04310 Teegatha Oh'Zheh - Parks	110,000				110,000
740c04810 Hamilton Boulevard Landscaping - Parks		200,000			200,000
740c05110 Greenbelt Barricades - Parks	20,000	15,000	15,000	15,000	65,000
740c05210 Phase 3 Landscaping CGC - Facilities	70,000	30,000			100,000
740c05310 Downtown Street Upgrades - Parks	25,000	50,000			75,000
Total Approved	570,000	500,000	785,000	165,000	2,020,000
Parks Facilities					
Approved					
750c00109 Security Cameras CGC - Facilities		20,000			20,000
750c00213 Pool Pump Replacement	175,000				175,000
750c00811 Wellness Equipment Replacement - Facilit	20,000	30,000	30,000	30,000	110,000
750c01013 Front Desk Upgrades	50,000				50,000
750c01211 Ozone Generator Rebuild CGC - Facilities	25,000				25,000
750c01313 CGC Arena Railing Retrofit	40,000				40,000
750c01411 Flooring Repairs - Facilities		50,000		50,000	100,000
750c01413 Pool Slide Structure Repair	150,000				150,000
750c01511 Wellness Centre Accessible Equipment	40,000	30,000	30,000	30,000	130,000
750c01513 Chlorine Generation System - CGC Aquatic	30,000	125,000			155,000
Total Approved	530,000	255,000	60,000	110,000	955,000
Total City of Whitehorse Approved Projects	**$ 14,305,550**	**$ 10,983,800**	**$ 3,967,200**	**$ 3,997,700**	**$ 33,254,250**

24-Apr-13 Community Services - Infrastructure Development Branch *2013 Project Listing for YECL*

Community	Project Description	Project Manager	Status
Beaver Creek	Community Road Upgrades	Kyle Rolling	Scoping
Burwash Landing	Water System	Kyle Rolling	Design
Burwash Landing	Community Road Upgrades	Kyle Rolling	Construction summer 2013
Carcross	Water System	Kirn Dhillon	Near completion
Carmacks	Sewer Collection and Road Finishing	Rick Kent	Near completion
Destruction Bay	Sewer Collection	Kyle Jansson	Near completion
Dawson City	Rock Creek Water System	Kirn Dhillon	Near completion
Faro	Water and Sewer Pipe Replacement	Jack Bowers	Construction summer 2013
Faro	Pumphouse	Jack Bowers	Design
Grizzly Valley	Deep Creek Water System	Kyle Jansson	Design
Haines Junction	Water Reservoir and Pumphouse	Kyle Rolling / Rick Kent	Construction summer 2013
Marsh Lake	Pumphouse	Rick Kent	Near completion
Keno	Water System	Kyle Jansson	Scoping
Mayo	Water Well and Treatment	Kyle Rolling	Construction summer 2013
Mayo	Water and Sewer Pipe Replacement	Kyle Rolling	Scoping
Mendenhall	Water System	Kyle Jansson	Construction summer 2013
Old Crow	Solid Waste Gasifier	Jack Bowers	Near completion
Old Crow	Water System	Jack Bowers	Near completion
Pelly Crossing	Community Road Upgrades	Kyle Rolling	Scoping
Ross River	Community Road Upgrades	Jack Bowers	Near completion
Ross River	Water System and Fire Hall	Jack Bowers	Near completion
Ross River	Wastewater System	Kyle Rolling	Scoping
Ross River	Suspension Bridge	Kyle Rolling	Scoping
Tagish	Taku Water System	Rick Kent	Design
Teslin	Community Road Upgrades	Kirn Dhillon	Near completion
Teslin	Wastewater System	Kirn Dhillon / Kyle Jansson	Design
Teslin	Water System	Kirn Dhillon	Near completion
Watson Lake	Water and Sewer Pipe Replacement	Kirn Dhillon / Kyle Jansson	Near completion
Watson Lake	Water System	Kirn Dhillon	Design

UCG-YECL-3

Reference: Board Order 2013-03, Appendix A, paragraph 13

> *"The Board agrees with UCG's comments regarding the filing of electronic spreadsheets such as Excel with formulae intact. The filing of the electronic version of schedules and tables allows for more efficient testing of the provided information. As a result, the Board directs that, in future, YEC will include Excel versions, with formulae intact of all schedules and tables used to support its filings."*

Request:

Please provide Excel versions, with formulae intact, of all schedules and tables that have been submitted as part of this Application.

Response:

Excel versions of all GRA Schedules submitted as part of the Application were provided when the Application was filed on May 27, 2013.

Excel versions of the following additional schedules are being filed with Yukon Electrical's responses to these information requests:

- Section 2, Attachments 1 through 21 – YUB-YECL-57 Attachments 1 to 21;
- Section 7, Attachment 1, pages 45-50 – CW-YECL-34(y) Attachment 1;
- Section 7, Attachment 1, pages 51-56 – CW-YECL-34(y) Attachment 2; and
- Business Case #27, Attachment 1 – YUB-YECL-48(m) Attachment 1.

The Gannett Fleming software outputs all reports in an MSWord format. As such an Excel version of a number of the schedules included in Section 7, Attachment 1 in the filing are not available.

There are no other material schedules or tables that were filed with the Application.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

UCG-YECL-4

Reference: May 27, 2013 Application Cover Letter, page 2

YECL states "*In Section 12 of this Application, Yukon Electrical has requested approval of a 6.5% interim refundable rate rider (Rider R) for electrical consumption on or after July 1 2013. By implementing the rate on July 1, 2013, Rider R will recover approximately 50% of Yukon Electrical's forecast shortfall in 2013.*"

Request:

Please provide details of all expected recoveries through Rider R by month for the period July 2013 through December 2014.

Response:

As Yukon Electrical does not have monthly revenue information for Yukon Energy, Yukon Electrical cannot provide expected Rider R recoveries per month. As shown in Schedule 12.1 of Yukon Electrical's 2013-2015 GRA application, the expected recovery for July to December 2013 is $1,825,000 while, at a continued interim refundable rate rider (Rider R) of 6.5%, the expected recovery for the period January to December 2014 would be approximately $4,067,000 as demonstrated in the table below.

Company	2014 Retail Revenue ($000s) [1] (A)	Rider R % [2] (B)	Expected Rider R Revenue ($000s) (A) * (B)
YECL	$50,393	6.5%	$3,276
YEC	$12,169	6.5%	$ 791
Total	$62,562		$4,067

[1] Retail revenue on existing rates, YECL 13/15 GRA Application, Schedule 2.1 L.56-58

[2] As approved in Board Order 2013-05 dated June 25, 2013

UCG-YECL-5

Reference: May 27, 2013 Application, page 1-3

YECL states "*Yukon Electrical was last before the Yukon Utilities Board ("Board") for the test years 2008-2009. Since then, Yukon Electrical has operated on 2009 primary rates with the exception of flowing through the impact of changes in fuel prices in accordance with Rider F and the Fuel Price Flow Through Deferral mechanism, as well as flowing through the impact of changes in the wholesale energy tariff from the Yukon Energy Corporation in accordance with the Purchased Power Flow Through Deferral mechanism.*"

Request:

(a) Please confirm that the bills of Yukon ratepayers have continued to change since 2008 due to the reliance by YEC and YECL on across-the-board percentage rate riders (e.g., Riders F, J and R) to recover approved rate revenue requirements and changes to fuel costs beyond what was provided by base rates.

(b) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for a residential customer living in Whitehorse using 1000 kWh, 1200 kWh and 1400 kWh per month in January 2008, January 2009, January 2010, January 2011, January 2012, January 2013, January 2014 and January 2015 assuming that the 2013, 2014 and 2015 rate adjustments proposed by YECL are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

(c) Please provide details of YECL's understanding of mitigation efforts in other jurisdictions if rate adjustments result in bill impacts in excess of a specific threshold.

(d) Please provide details of YECL's position regarding mitigation efforts that should be imposed if rate adjustments in the Yukon result in bill impacts in excess of 10%.

Response:

(a) Confirmed. Please note that Fuel Adjustment Rider, Rider F, is not applied on an across-the-board percentage basis, but is applied on a cents per kWh basis to consumption.

(b) Please refer to UCG-YECL-5(b) Attachment 1 for the requested detailed bill calculations.

(c) Yukon Electrical is aware of three rate impact mitigation methods that other jurisdictions have used:

1) Government Subsidy

An example of this mitigation method recently occurred in the Northwest Territories Power Corporation's (NTPC) 2012-14 GRA where the Government of the Northwest Territories (GNWT) provided subsidization to NTPC to assist in transitioning rates to recover the full 2013-14 revenue requirement by the end of a 4-year transition period.

2) Collecting approved balances over a longer period of time

This approach has been used by ATCO Electric as well as Northland Utilities depending on the circumstances. For example, when considering the collection of approved amounts, utilities will consider the rate impact to customers and will propose a recovery period that achieves a balance between the utility being able to recover approved costs and the recovery rate not resulting in rate shock.

3) Cross-subsidization between rate classes

If the cost of service and a 100% revenue to cost ratio for a particular rate class results in rate shock for a particular rate class, the utility may propose a revenue to cost ratio of less than 100%. This effectively results in customer class cross-subsidization.

(d) Yukon Electrical's position on this has been, and continues to be, that if a bill increase at a point in time (month over month) exceeds 10%, any of the three methods that might be available as described in part (c) can be employed to address rate shock. Further to this, however, and as detailed in UCG-YECL-5(d) Attachment 1, there have been a couple of instances in the past 20 years where Yukon residential non-government bills have increased by more than 10%. Yukon Electrical also notes the Northwest Territories PUB has set a bill increase cap of 15% with respect to Northland Utilities (NWT). Finally, also as detailed in UCG-YECL-5(d) Attachment 1, Yukon Electrical notes there will be no bill increases in 2014 or 2015 approaching 10% based on information currently available to Yukon Electrical.

Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1000 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1000	1000	1000	1000	1000	1000	1000	1000	1000
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
Rates	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
Rates	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
Relief	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BASE RATE		$ 110.50	$ 110.50	$ 110.50	$ 110.50	$ 136.05	$ 136.05	$ 136.05	$ 136.05	$ 136.05
	RIDER F - FUEL ADJUSTMENT RIDER		$ 9.64	$ 18.60	$ (3.54)	$ (0.90)	$ 3.52	$ 1.91	$ 1.91	$ 1.91	$ 1.91
	APPEAL RIDER										
	YEC SHORTFALL		$ 16.50	$ 12.65	$ 13.77	$ 13.77	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 8.71	$ 14.98	$ 14.98	$ 14.98
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 5.10	$ 4.93	$ -	$ -
	YECL SHORTFALL		$ -	$ 5.53	$ 11.63	$ 11.63	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 8.84	$ 16.46	$ 16.46
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.05	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 136.64**	**$ 147.28**	**$ 132.36**	**$ 135.00**	**$ 139.57**	**$ 151.77**	**$ 166.71**	**$ 178.45**	**$ 169.40**
	% Change M over M (Before Relief)			7.8%	-10.1%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.55)	$ (0.55)	$ (0.55)	$ (0.55)	$ (1.02)	$ (1.02)	$ (1.02)	$ (1.02)	$ (1.02)
	TOTAL RELIEF		$ (19.12)	$ (19.12)	$ (27.16)	$ (27.16)	$ (27.63)	$ (27.63)	$ (27.63)	$ (27.63)	$ (27.63)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 117.52**	**$ 128.16**	**$ 105.20**	**$ 107.84**	**$ 111.94**	**$ 124.14**	**$ 139.08**	**$ 150.82**	**$ 141.77**
	% Change M over M (Including Relief)			9.1%	-17.9%	2.5%	3.8%	10.9%	12.0%	8.4%	-6.0%

(1) Reflects Rates per Board Order 2013-04 with respect to Yukon Energy's 2012-2013 GRA
(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief

Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1200 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1200	1200	1200	1200	1200	1200	1200	1200	1200
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
Rates	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
Rates	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ 20.90	$ 20.90	$ 20.90	$ 20.90	$ 25.64	$ 25.64	$ 25.64	$ 25.64	$ 25.64
	BASE RATE		$ 131.40	$ 131.40	$ 131.40	$ 131.40	$ 161.69	$ 161.69	$ 161.69	$ 161.69	$ 161.69
	RIDER F - FUEL ADJUSTMENT RIDER		$ 11.57	$ 22.32	$ (4.25)	$ (1.08)	$ 4.22	$ 2.29	$ 2.29	$ 2.29	$ 2.29
	APPEAL RIDER										
	YEC SHORTFALL		$ 19.62	$ 15.05	$ 16.37	$ 16.37	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 10.35	$ 17.80	$ 17.80	$ 17.80
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 6.06	$ 5.85	$ -	$ -
	YECL SHORTFALL		$ -	$ 6.57	$ 13.83	$ 13.83	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 10.51	$ 19.56	$ 19.56
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.75	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 162.59**	**$ 175.34**	**$ 157.35**	**$ 160.52**	**$ 165.91**	**$ 180.39**	**$ 198.14**	**$ 212.09**	**$ 201.34**
	% Change M over M (Before Relief)			7.8%	-10.3%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.66)	$ (0.66)	$ (0.66)	$ (0.66)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)
	TOTAL RELIEF		$ (19.23)	$ (19.23)	$ (27.27)	$ (27.27)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 143.36**	**$ 156.11**	**$ 130.08**	**$ 133.25**	**$ 138.09**	**$ 152.57**	**$ 170.32**	**$ 184.27**	**$ 173.52**
	% Change M over M (Including Relief)			8.9%	-16.7%	2.4%	3.6%	10.5%	11.6%	8.2%	-5.8%

(1) Reflects Rates per Board Order 2013-04 with respect to Yukon Energy's 2012-2013 GRA
(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief

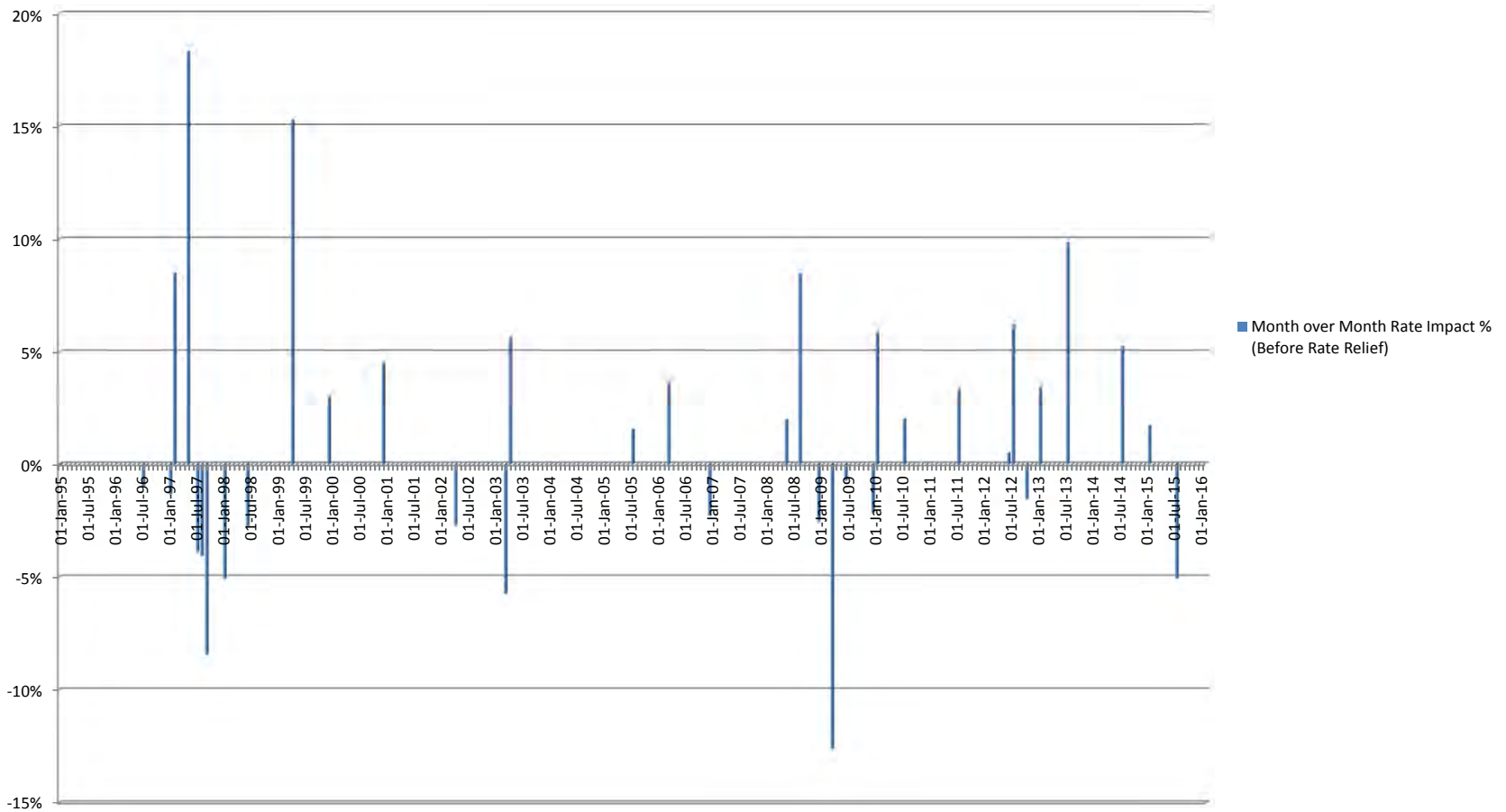
Yukon Electrical Company Limited (YECL)

Whitehorse Residential Monthly Bill Calculations - Rate 1160
for 1400 kW.h Monthly Consumption

	COMPONENT		01-Jan-08	01-Jan-09	01-Jan-10	01-Jan-11	01-Jan-12	01-Jan-13	01-Jan-14	01-Jan-15	01-Jan-16
	ENERGY:	kW.h	1200	1200	1200	1200	1200	1200	1200	1200	1200
	CUSTOMER CHARGE	$ / month	$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE (1st Block 0-1000 kWh)	¢ / kW.h	9.86	9.86	9.86	9.86	12.14	12.14	12.14	12.14	12.14
	ENERGY CHARGE (2nd Block 1001-2500 kWh)		10.45	10.45	10.45	10.45	12.82	12.82	12.82	12.82	12.82
Rates	RIDER F - FUEL ADJUSTMENT RIDER	¢ / kW.h	0.9638	1.860	-0.354	-0.090	0.352	0.191	0.191	0.191	0.191
Rates	APPEAL RIDER	%									
Rates	YEC SHORTFALL	%	14.930%	11.450%	12.460%	12.460%					
Rates	RIDER J - YEC SHORTFALL 2012	%						6.40%	11.01%	11.01%	11.01%
Rates	RIDER R1 - YEC SHORTFALL 2013	%						3.750%	3.620%	0.000%	0.000%
Rates	YECL SHORTFALL	%		5.0%	10.526%	10.526%					
Rates	RIDER R - YECL SHORTFALL (13-15)	%							6.5%	12.1%	12.1%
Rates	YECL SHORTFALL ADJUSTMENT (13-15)	%								6.7%	0.0%
Relief	RATE STABILITY FUND (CUSTOMER)	%	-9.975%	-9.975%	Replaced by Interim Electrical Rebate						
Relief	RATE STABILITY FUND (1ST ENERGY BLOCK)	%	-17.6279%	-17.6279%							
Relief	RATE STABILITY FUND (2ND ENERGY BLOCK)	%									
Relief	INTERIM ELECTRICAL REBATE (up to 1000 kWh)	¢ / kW.h			-2.661	-2.661	-2.661	-2.661	-2.661	-2.661	-2.661
	YUKON RELIEF/INCOME TAX REBATE	%	-0.500%	-0.500%	-0.500%	-0.500%	-0.750%	-0.750%	-0.750%	-0.750%	-0.750%
	CUSTOMER CHARGE		$ 11.90	$ 11.90	$ 11.90	$ 11.90	$ 14.65	$ 14.65	$ 14.65	$ 14.65	$ 14.65
	ENERGY CHARGE 1st Block		$ 98.60	$ 98.60	$ 98.60	$ 98.60	$ 121.40	$ 121.40	$ 121.40	$ 121.40	$ 121.40
	ENERGY CHARGE 2nd Block		$ 20.90	$ 20.90	$ 20.90	$ 20.90	$ 25.64	$ 25.64	$ 25.64	$ 25.64	$ 25.64
	BASE RATE		$ 131.40	$ 131.40	$ 131.40	$ 131.40	$ 161.69	$ 161.69	$ 161.69	$ 161.69	$ 161.69
	RIDER F - FUEL ADJUSTMENT RIDER		$ 11.57	$ 22.32	$ (4.25)	$ (1.08)	$ 4.22	$ 2.29	$ 2.29	$ 2.29	$ 2.29
	APPEAL RIDER										
	YEC SHORTFALL		$ 19.62	$ 15.05	$ 16.37	$ 16.37	$ -	$ -	$ -	$ -	$ -
	RIDER J - YEC SHORTFALL 2012		$ -	$ -	$ -	$ -	$ -	$ 10.35	$ 17.80	$ 17.80	$ 17.80
	RIDER R1 - YEC SHORTFALL 2013		$ -	$ -	$ -	$ -	$ -	$ 6.06	$ 5.85	$ -	$ -
	YECL SHORTFALL		$ -	$ 6.57	$ 13.83	$ 13.83	$ -	$ -	$ -	$ -	$ -
	RIDER R - YECL SHORTFALL (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ 10.51	$ 19.56	$ 19.56
	YECL SHORTFALL ADJUSTMENT (13-15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.75	$ -
	TOTAL (BEFORE RATE RELIEF AND GST)		**$ 162.59**	**$ 175.34**	**$ 157.35**	**$ 160.52**	**$ 165.91**	**$ 180.39**	**$ 198.14**	**$ 212.09**	**$ 201.34**
	% Change M over M (Before Relief)			7.8%	-10.3%	2.0%	3.4%	8.7%	9.8%	7.0%	-5.1%
	RATE STABILITY FUND (CUSTOMER)		$ (1.19)	$ (1.19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (1ST ENERGY BLOCK)		$ (17.38)	$ (17.38)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	RATE STABILITY FUND (2ND ENERGY BLOCK)										
	INTERIM ELECTRICAL REBATE (up to 1000 kWh)		$ -	$ -	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)	$ (26.61)
	YUKON RELIEF/INCOME TAX REBATE		$ (0.66)	$ (0.66)	$ (0.66)	$ (0.66)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)	$ (1.21)
	TOTAL RELIEF		$ (19.23)	$ (19.23)	$ (27.27)	$ (27.27)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)	$ (27.82)
	TOTAL (INCLUDING RATE RELIEF, BEFORE GST)		**$ 143.36**	**$ 156.11**	**$ 130.08**	**$ 133.25**	**$ 138.09**	**$ 152.57**	**$ 170.32**	**$ 184.27**	**$ 173.52**
	% Change M over M (Including Relief)			8.9%	-16.7%	2.4%	3.6%	10.5%	11.6%	8.2%	-5.8%

(1) Reflects Rates per Board Order 2013-04 with respect to Yukon Energy's 2012-2013 GRA
(2) Reflects Rate per Board Order 2013-05 with respect to Yukon Electrical's 2013-2015 GRA
(3) Collection of remaining 2013 revenue requirement over the period July '14-June '15
(4) Collection of 2014 revenue requirment over the period July '14-June '15
(5) Collection of 2015 revenue requirement begins January '15
(6) Assumes no change in Yukon Governement Bill Relief

Whitehorse Residential - Rate 1160
Historical (Jan'95-Jul'13) and Forecast (Aug'13-Dec'15) Month over Month Rate Impact %
(Before Rate Relief)



UCG-YECL-6

Reference: May 27, 2013 Application, page 1-4

YECL states "*Further to the above, the Board directed in Board Order 2010-13 that a joint Cost of Service Study was to be filed within six months of the expiry of OIC 2008/149. Given that OIC 2008/149 was superseded by OIC 2012/68 with the effect of no rate rebalancing until after December 31, 2013, Yukon Electrical is now forecasting a joint Phase II GRA with Yukon Energy will be filed in 2014 that will include a Cost of Service Study, Rate Design, Rate Schedules and Terms and Conditions based on Yukon Electrical's and Yukon Energy's most recently approved revenue requirements.*"

Request:

(a) Please provide details of the steps that YECL expects to take to compile and submit a joint Phase II GRA as well as the amount of time needed to finish these steps.

(b) Please provide details on what work has been completed to date on the next Phase II GRA and/or when this work is to commence.

Response:

(a) Assuming OIC-2008/149 which was amended by OIC-2012/68 expires on December 31, 2013 and utilities are expected to file a joint phase application within 6 months of the expiry of the rate directive, as ordered in Board Order 2010-13, Yukon Electrical and Yukon Energy will work together to submit a joint Phase II GRA based on the total 2013 revenue requirement of the two utilities. It is expected that the joint cost of service study and rate design will commence in late 2013 utilizing Yukon Electrical's proposed 2013 revenue requirement and Yukon Energy's approved 2013 revenue requirement. Based on the experience associated with the 2010 joint Phase II, Yukon Electrical forecasts that it may take between 4 to 6 months to prepare this application.

(b) No work on the next Phase II GRA has commenced to-date. It is expected that this work will commence in late 2013.

UCG-YECL-7

Reference: May 27, 2013 Application, page 1-13

YECL states "*On February 13, 2008, the Canadian Accounting Standards Board confirmed that IFRS will replace Canadian Generally Accepted Accounting Principles (GAAP) for annual financial statements relating to fiscal years beginning on or after January 1, 2011. IFRS uses a conceptual framework similar to GAAP, but there are significant differences in recognition, measurement and disclosures. The most significant difference from GAAP is the absence of the recognition of regulatory assets / liabilities and related deferral accounts. Beginning in 2011, Yukon Electrical, consistent with its parent company, no longer recognizes regulatory assets and liabilities in its IFRS Financial Statements but continues to do so for utility earnings purposes.*"

Request:

(a) Please confirm YECL's understanding that the International Accounting Standards Board has announced deferrals to the adoption of IFRS and that it announced IFRS adoption deferrals to January 1, 2013, January 1, 2014 and January 1, 2015 in March 2012, September 2012 and February 2013 respectively and that these deferrals are available to rate-regulated entities (i.e. YECL).

(b) Please identify the additional costs that YECL has and will incur by not deferring the adoption of International Financial Reporting Standards until January 1, 2015 to allow issues associated with rate-regulated accounting under IFRS to be resolved.

(c) Please confirm YECL's understanding that it will not be able to adopt changes that may be made to rate-regulated accounting policies as a result of the current ongoing review by the IASB.

(d) Please identify where these additional costs are included within YECL's revenue requirements for 2010, 2011 and 2012 as well as the proposed revenue requirements for 2013, 2014 and 2015.

Response:

(a) Not confirmed. It was the Canadian Accounting Standards Board that announced that rate-regulated entities such as Yukon Electrical may opt to defer adoption of IFRS to January 1, 2013, January 1, 2014 and January 1, 2015 in March 2012, September 2012 and February 2013, respectively.

(b) In 2011, all IFRS transition-related work was handled by the Supervisor, Financial Services. As such, no incremental costs were incurred. In 2012, the Corporate Accountant and Manager, Financial Reporting and Accounting, North of 60 positions were added. Yukon Electrical estimates that approximately 10% of the Corporate Accountant's workload and 5% of the workload for each of the Supervisor and Manager is related to IFRS in 2012. The approximate cost of the time spent on IFRS in 2012 was $43,000. On a go forward basis, the time spent on IFRS is expected to remain consistent with 2012. As a result, for 2013, 2014, and 2015, the approximate cost of the time spent on IFRS is $44,500, $46,000 and $47,500, respectively, based on a labour inflation rate of 3.5% per year.

(c) The IASB released an Exposure Draft (ED) in April 2013 for an interim standard which would allow for the grandfathering of current accounting practices for rate-regulated activities upon first-time adoption of IFRS. If this ED is issued as drafted, Yukon Electrical will not be able to apply it as IFRS has already been adopted and this standard would only apply to those entities that have not yet adopted IFRS (first time adoption only).

However, this interim standard is intended to provide temporary guidance only until the IASB has completed its comprehensive project on accounting for rate-regulated activities. Once that project is completed and guidance for rate-regulated entities is issued, Yukon Electrical would be required to align with that guidance along with all other rate-regulated entities reporting under IFRS.

(d) These additional costs are included in 72100 – Administrative on Schedules 5.1, 5.2 and 5.3 of the Application.

UCG-YECL-8

Reference: May 27, 2013 Application, pages 2-1 – 2-2

YECL states "*Yukon Electrical forecasts the total primary non-industrial sales in 2013 to increase 2.3% (on a weather-normalized basis) and 1.9% in each of 2014 and 2015. The 2.3% growth in sales in 2013 is consistent with the recently applied for and Board approved Yukon Energy 2013 forecast growth in wholesale sales to Yukon Electrical of 2.26%. Including the sales to the Yukon Electrical industrial customer, Whitehorse Copper Tailings, the growth in total sales in 2013 to 2015 would be 2.6%, 3.1% and 1.9%, respectively.*"

Request:

(a) Please confirm whether the electrical sales by customer class shown at the top of page 2-2 for the 2013-2015 test period are weather normalized.

(b) Please confirm the 2013 forecast wholesale sales approved by the YUB for Yukon Energy Corporation in its Order 2013-03 issued on June 17, 2013.

(c) Please provide details on when YECL's current sales forecasts for 2013-2015 were determined for this rates application.

(d) Please identify the impact that demand side management is expected to have on sales levels in 2013, 2014 and 2015. Explain how this impact has been incorporated into the sales forecast and provide a revised version of Schedule 2.1 showing the sales forecast for 2013 – 2015 with DSM impacts isolated.

(e) Please provide monthly details of Whitehorse Copper's forecasted electricity use, demand and bill component totals for 2013, 2014 and 2015.

Response:

(a) As indicated on page 2-5 of the Application, the residential energy consumption forecast presented on Table 1 is derived based on a weather-normalized UPC, with the exception of energy consumption for Keno City, Stewart Crossing and Swift River, where their actual UPC were used. For all practical purposes, however, the residential energy forecast on Table 1 should be considered

weather-normalized, as the combined share of energy consumption of those communities indicated above accounts for only a marginal fraction of the Yukon's total residential energy consumption (0.2% in 2012, please refer to Table 3, page 2-4 of the Application).

As for the commercial energy consumption forecast presented in Table 1, as indicated on page 2-6 of the Application, only Whitehorse commercial UPC was weather-normalized, however, Whitehorse commercial energy consumption accounts for a significant share of Yukon's total commercial energy consumption (85.3% in 2012, please refer to Table 3, page 2-4 of the Application).

Energy consumption related to Street and Private lights presented in Table 1 are not weather-normalized.

(b) Based on Schedule 9 of Yukon Energy's, June 20, 2013, Compliance Re-filing, wholesale sales were approved to be 307,147 MWh for 2013.

(c) The sales forecast for this GRA was developed between February and April of 2013 utilizing actual sales data up to December 31, 2012.

(d) Demand Side Management is assumed to be approved to commence in 2014, and its total impact is forecast to be a reduction in sales of 99 MWh in 2014 and 707 MWh in 2015. Please refer to WL-YECL-8(a) Attachment 1 for more detail.

(e) Please refer to UCG-YECL-8(e) Attachment 1 for the requested information.

The Yukon Electrical Company Limited
Industrial Rate Forecast

Industrial Primary Rate Schedule 39 effective January 1, 2012

Demand Charge	$ per kVA	$ 15.94
Energy	$/kWh	$0.0808

Forecast Charge Demand (kVA):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	1,250	1,250	1,250	3,750
2014	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
2015	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000

Forecast Energy (kWh):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	520,800	504,000	-	1,024,800
2014	-	-	520,800	504,000	520,800	504,000	520,800	520,800	504,000	520,800	504,000	-	4,620,000
2015	-	-	520,800	504,000	520,800	504,000	520,800	520,800	504,000	520,800	504,000	-	4,620,000

Forecast Revenue ($000):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2013	-	-	-	-	-	-	-	-	-	62	61	20	143
2014	20	20	62	61	62	61	62	62	61	62	61	20	612
2015	20	20	62	61	62	61	62	62	61	62	61	20	612

UCG-YECL-9

Reference: May 27, 2013 Application, page 2-5

YECL states "*Weather-normalized UPC is obtained based on a two-step approach where, in the first step, the historical average monthly UPC is regressed on reported monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in first step is multiplied by the difference between the actual HDD and the "Normal" HDD. "Normal" HDD is defined as a twenty-year rolling average of HDD.*"

July 27, 2012 YEC 2012-2013 GRA, YECL-YEC-1-3

YEC states "*Heating Degree Days (HDD) analysis showed that the temperature in Whitehorse was colder in 2011 than the 10-year average. HDD for 7 winter months (Jan-Apr, Oct-Dec) showed approximately 66 higher HDD in 2011 compared to 10-year average (columns B and C in Table 1 of Attachment 1)*.

Request:

(a) Please provide the source documents for the monthly heating degree days provided in the Application at Section 2, Attachment 20.

(b) Please provide details of when the YUB approved the use of the 20 year rolling average Heating Degree Days as a method of normalizing YECL's temperature-sensitive sales.

(c) Please explain the difference between the 2011 heating degree days for Whitehorse identified by YEC as "actual" and the 2011 "actual" heating degree days provided in YECL's Application at Section 2, Attachment 20.

Response:

(a) Please refer to Environment Canada's website (http://climate.weather.gc.ca/).

(b) In Yukon Electrical's 2008-2009 GRA, Yukon Electrical used 20-year rolling average heating degree days (HDD) to define "Normal" temperature used in its weather normalization. The Board implicitly approved Yukon Electrical's

definition of "Normal" temperature, as there was no objection raised in Board Order 2009-2 issued on February 12, 2009. ATCO Electric and Fortis Alberta have previously used a 20-year rolling average HDD in their past General Tariff Applications with the Alberta Utilities Commissions, which have been approved. Furthermore, many utilities in Canada and the U.S. have used that definition of "Normal" temperature as evidenced in Itron's 2005 survey (please refer to Table 1, Section 11, Attachment 1 of the Application).

(c) Yukon Energy reported HDD of 6,649 for Whitehorse in 2011 (Source: 2012-2013 Yukon Energy GRA, YECL-YEC-1-1(a) Attachment 1), while Yukon Electrical reported 6,685 for Whitehorse for the same year. Although the difference is not large enough to materially change the sales forecast, the difference could be due to one or a combination of the following factors:

- Environment Canada's revisions to reported weather data;
- Using a different weather station in Whitehorse. For example, there are 2 weather stations in Whitehorse whose weather data is reported by Environment Canada on their website cited in part (a) above; and or
- The estimating method used by each utility for missing data. Yukon Electrical notes that there has been missing weather data reported by Environment Canada with increased frequencies in recent years.

UCG-YECL-10

Reference: May 27, 2013 Application, page 2-8

YECL states "*As WHCT is a single industrial customer that could contribute materially higher or lower than 1.4% of Yukon Electrical's total forecast sales and the exact timing of its start-up and eventual load are not within the control of Yukon Electrical, Yukon Electrical is requesting a deferral account relating to WHCT sales uncertainty. This deferral account is proposed to capture the difference between WHCT net revenue on existing Rate 39 less forecast purchase power price applied to forecast sales, and WHCT net revenue on existing Rate 39 less forecast purchased power price applied to actual sales. The net revenue will be defined using Rate 39 effective January 1, 2013, that was used to generate the revenue on existing rates in Schedule 2.1, less the forecast price of purchase power stated in Schedule 3.1 assumed in the revenue requirement. Differences between forecast and actual will be refunded to or collected from customers.*"

Request:

(a) Please provide examples where the YUB has allowed the creation of a deferral account related to the sales forecast of a utility.

(b) Please explain how the requested deferral account lessens the risk faced by YECL.

Response:

(a) Yukon Electrical is aware of one example in 1998 where the YUB ordered the creation of a deferral account related to the sales of Yukon Energy to the Faro mine site under Rate Schedule 34. In Board Order 1998-5, the Board stated:

> All revenue derived from Rate Schedule 34, less reasonable incremental costs associated with supplying the Faro mine site under this rate schedule, shall be placed in a deferral account for subsequent application to the benefit of customers as directed by the Board.

(b) The requested deferral account neither decreases nor increases the risk faced by Yukon Electrical as compared to its 2008-2009 GRA. This is due to fact that no industrial sales were forecasted as part of Yukon Electrical's 2008-2009 GRA.

UCG-YECL-11

Reference: May 27, 2013 Application, page 3-1

YECL states "*Yukon Electrical was directed in Board Order 2009-2 to capitalize the incremental purchased power costs incurred due to Fish Lake rebuilds in 2008/2009. Consistent with this Order, Yukon Electrical has capitalized the incremental purchase power costs incurred for the period in which Fish Lake Unit #1 was out of service after the catastrophic failure in March 2010.*"

Request:

(a) Please provide details of the incremental purchased power costs incurred when Fish Lake was out of service following the March 2010 failure including if any of these costs are being incurred during the 2013-2015 test period.

(b) Please provide details of when the YUB specifically approved the capitalization of the incremental purchased power costs incurred when Fish Lake was out of service following the March 2010 failure.

Response:

(a) Incremental purchased power costs of $346,000 for 2010, $367,000 for 2011, $402,000 for 2012 and $369,000 for 2013 (forecast) were incurred when Fish Lake was out of service following the March 2010 failure.

(b) The YUB has not specifically approved the capitalization of the incremental purchased power costs incurred since Fish Lake Unit #1 went out of service following the March 2010 failure. Yukon Electrical is requesting these amounts be approved as part of this Application.

UCG-YECL-12

Reference: May 27, 2013 Application, page 3-2

YECL states "*The cost of purchase power in this Application is based on Yukon Energy's rates that are currently in place for primary energy and secondary sales and are outlined on Schedule 3.1, lines 6 and 7. These rates do not include any adjustment to the rates associated with Yukon Energy's applied for but not yet approved Energy Reconciliation Adjustment (ERA). Any increases or decreases to these rates for 2013 and thereafter will be flowed through to Yukon Electrical's customers.*"

Request:

(a) Please confirm YECL's understanding that the steps that YEC included in its 2012-2013 General Rates Application to update the Energy Reconciliation Adjustment and reactivate it effective January 1, 2012 were not approved by the YUB in its Order 2013-01 issued March 25, 2013.

(b) Please identify YEC's current application for the Energy Reconciliation Adjustment that has not yet been addressed by the YUB.

(c) Please explain how "any increases or decreases to these rates for 2013 and thereafter will be flowed through to Yukon Electrical's customers".

Response:

(a) Confirmed.

(b) It is Yukon Electrical's understanding that Yukon Energy's 2012-2013 GRA proposed Energy Reconciliation Adjustment has not been approved. In Board Order 2013-03, the Board stated:

> The Board notes that the revised DCF proposal was not filed jointly by YEC and YECL and that there was not a joint recommendation by the companies on how to amend the wording regarding the ERA in Rate Schedule 42. The Board considers that the revised DCF proposal has not been tested in a proceeding. Given the foregoing, the Board does not approve the revised DCF proposal filed in

YEC's 2012-13 GRA compliance filing. Consequently, the Board will not allow any changes regarding 2012 and the effects of any DCF proposal.

YEC may file a future revised DCF proposal and ERA application. The Board prefers a joint filing from YEC and YECL. However, if agreement cannot be reached, a filing in which the companies state which aspects of the revised DCF proposal and ERA amendment they agree upon, the aspects they disagree upon, and the position of each company on those aspects they disagree upon is acceptable. The filing must also address the concerns raised in Board Order 2013-01 Attachment A: Reasons for Decision. This future revised DCF proposal and ERA application will be separate from the compliance filing directed in this order.

(c) The total impact of any increases or decreases to these rates for 2013 and thereafter would be followed through to customers through a Board approved Rider.

UCG-YECL-13

Reference: May 27, 2013 Application, page 3-3

YECL states "*Total forecast purchases are determined by applying a forecast line loss percentage to Yukon Electrical's sales load forecast that was discussed in Section 2. Overall, line losses are determined by using a five-year historical average of 6.2%. This is consistent with the approach approved in Board Order 2009-2.*"

Request:

(a) Please provide details of the line loss analysis that confirms that the most recent 5-year average of line losses on YECL's various systems is 6.2%.

(b) Please describe the work that YECL has undertaken to reduce the level of line losses on its various systems since 2008 and provide the analysis that shows how line losses have been reduced.

Response:

(a) Please refer to UCG-YECL-13(a) Attachment 1 for the calculation of the 5-year average of 6.2%.

(b) Steps Yukon Electrical has implemented to reduce losses:

- Yukon Electrical installs maximum-sized conductors based on engineering standards for all new extensions and system improvement distribution lines. This inherently improves line losses when old distribution lines are upgraded with larger conductors.

- Yukon Electrical has converted various sections of the distribution system to higher voltages, such as the Hillcrest subdivision. Line losses are reduced on system loading when the distribution voltages are increased.

- Yukon Electrical evaluates the life cycle costs of transformers and selects a supplier based on the lowest life time cost. The large power transformers for Shipyards and Whistlebend substations were tendered,

designed and built to ensure impedances were matched to reduce internal losses to a minimum.

- All new revenue meters purchased are electronic meters which have lower internal losses than mechanical meters.

- Yukon Electrical is working jointly with Yukon Energy to evaluate LED street lights for the Yukon as well as a Demand Side Management Program. Both these initiatives reduce load and, therefore, losses.

Yukon Electrical's sales in MWh have grown by 8.2% from 2008 to 2012 (from 292,647 MWh to 316,575 MWh). The associated increase in load would normally be expected to increase losses. However, Yukon Electrical's losses over the same period have actually remained flat, as show on line 4 of Schedule 3.2 in the Application. Therefore, Yukon Electrical believes the above noted steps it has taken to reduce losses have been successful in preventing the level of losses from increasing as load has grown from 2008 to 2012.

The Yukon Electrical Company Limited
Calculation of 5-Year Average Line Losses

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	5-Year Average
Losses - % (Sch. 3.2, line 4 of Application)	6.2%	6.2%	6.1%	6.1%	6.4%	6.2%

UCG-YECL-14

Reference: May 27, 2013 Application, page 4-1

YECL states "*The forecast fuel cost increase of $974,000 in 2013 is mainly due to the inclusion of the Rider F fuel rider in base rates for the test period. Prior to 2013, Yukon Electrical recovered the difference between the forecast 2009 fuel rates and the current fuel rate using Rider F.*"

May 27, 2013 Application, page 12-2

YECL states "*The Fuel Adjustment Rider, Rider F, will remain in place, to recover diesel fuel cost variances. It will be adjusted as required by the current Rider F fuel cost recovery process.*"

Request:

(a) Please explain what YECL is doing with respect to "the inclusion of the Rider F fuel rider in base rates for the test period" if the Rider F is supposed to be continued as a rate rider.

(b) Please provide details of the YUB order that allows YECL to include the Rider F fuel rider in base rates.

Response:

(a) Consistent with past practice, this application is updating the forecast price of diesel for the test period of January 1, 2013 through to December 31, 2015. These updated fuel prices (as shown on Schedule 4.2 Line 1-7, for the 2013-2015 test years) are used as the price input to determine the forecast fuel expense. Once fuel prices are approved as part of an overall decision on this Application, Yukon Electrical will incorporate them into its Rider F calculations January 1, 2013 forward.

(b) As part of this Application, Yukon Electrical is requesting a Fuel Price Flow Through Deferral. Assuming this deferral is approved by the Board, Yukon Electrical will seek to recover / refund differences between forecast and actual fuel prices via Rider F or other method approved by the Board.

UCG-YECL-15

Reference: May 27, 2013 Application, page 4-1

YECL states "*Fuel is purchased on an ongoing basis for each of the five isolated diesel plants operated by Yukon Electrical. Yukon Electrical conducts a diesel fuel tendering process in which a vendor is selected to be the provider of diesel fuel to Yukon Electrical. The current diesel fuel arrangements are due to be retendered early in 2014.*"

Request:

(a) Please explain when the new tender for diesel fuel purchases will be effective.

(b) Please confirm that any new diesel fuel prices will be reflected in fuel costs paid by Yukon ratepayers through the Rider F.

Response:

(a) Currently, Yukon Electrical has a supply contract with Suncor Energy Partners for fuel delivery to the following communities: Beaver Creek, Haines Junction, Destruction Bay, Swift River, Teslin, Watson Lake, Pelly Crossing, Ross River and Stewart Crossing. This contract expires on January 31, 2014.

Yukon Electrical recently completed contract negotiations with Air North for a new supply agreement for Old Crow. The new contract is for a three year term expiring on June 30, 2016.

Yukon Electrical would like to emphasize that new contracts rarely have significant changes to the pricing structure. Pricing is driven by the market and reflected in rack prices which will always be a variable in fuel contract pricing.

(b) Confirmed. Yukon Electrical has requested a Fuel Price Flow Through Deferral in Section 4 of its Application. To the extent actual fuel prices differ from forecast fuel prices, the impact of the difference will be reflected in fuel costs paid by Yukon ratepayers through Rider F or another Board approved mechanism.

UCG-YECL-16

Reference: May 27, 2013 Application, page 4-1 - 4-2

YECL states "*Beginning in 2013, a supply of Liquid Natural Gas (LNG) for the Watson Lake power plant will be sourced from FortisBC. Please refer to Business Case #6, Watson Lake Bi-Fuel Project, for further information regarding the Watson Lake power plant generating electricity with LNG as well as diesel fuel beginning in 2013.*"

Request:

(a) Please confirm that the 3 page business case provided in this Application is all that was required to gain management approval of the Watson Lake Bi-Fuel Project expenditures of $1,047,000 during the 2012-2014 period. If not, please provide all documentation used to gain management approval. Please provide all related regulatory and net present value analysis on Excel format.

(b) Please confirm the total capital and operating cost of the Watson Lake Bi-Fuel Project.

(c) Since the Watson Lake Bi-Fuel Project has related expenditures over $1 million, please explain when YECL will be taking steps to have this project reviewed pursuant to Section 3 of the *Public Utilities Act*.

Response:

(a) Not confirmed. Yukon Electrical has evaluated the project to determine that displacement of diesel fuel is viable to reduce emissions and fuel costs. Business Case #6 summarizes the initiative for Yukon Electrical to deliver those benefits that also reduce the dependency of Watson Lake on a single fuel. Yukon Electrical needed to confirm that the provision of reliable service to the Watson Lake grid is maintained. Yukon Electrical also needed to confirm that development of a secure supply of natural gas is viable as part of a reliable supply chain to procure LNG, transport to site, store and convert to natural gas and that an acceptable technology to incorporate its use is commercially available. Please refer to YUB-YECL 42(a) for economic analyses also prepared as part of gaining management approval.

(b) Please refer to YUB-YECL 42(a) for total capital and operating cost information for the Watson Lake Bi-Fuel Project.

(c) Similar to all other capital projects forecast in the 2013-2015, Yukon Electrical is seeking approval from the YUB for the Watson Lake Bi-Fuel Project as part of this GRA Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

UCG-YECL-17

Reference: May 27, 2013 Application, page 4-2

YECL states "*Plant efficiencies are based on the average efficiencies of the previous five years adjusted for any changes due to the replacement of units. This is consistent with the approach approved in Board Order 2009-2.*"

Request:

(a) Please provide details of the diesel fuel efficiencies assumed for 2013-2015 as well as details of the previous 5 years efficiencies which were used to support the forecast including how they were measured. Please provide all detailed schedules in Excel format.

(b) Please explain work that YECL has undertaken to improve diesel fuel efficiencies on its various systems since 2008.

Response:

(a) Please refer to schedule 4.2 lines 17-23 for detailed plant efficiencies for all isolated generation plants for 2008-2015. The net heat rate of a plant is determined by dividing the net generation supply from the power plant by the litres of diesel fuel that is consumed.

(b) Please refer to UCG-YECL-17(b) Attachment 1 for a list of specific projects that will contribute to diesel fuel efficiency. The largest single component associated with maintaining optimal diesel fuel efficiency is ensuring the diesel engines are operated and maintained in accordance with manufacturer specifications, this includes the major overhauls that are identified on UCG-YECL-17(b) Attachment 1. Yukon Electrical also achieves this by timely completion of minor overhauls included in our Production costs in account 84600. Yukon Electrical monitors operating conditions and will adjust generating equipment for the best efficiency. Some examples of this work include installation of fuel coolers on fuel supply lines, dedicated fresh air intakes and automated louvers.

Generation Plant Efficiencies

Highlighted projects contribute to improved diesel fuel efficiencies

Project Name	Appropriation Type	2008	2009	2010	2011	2012	2013	2014	2015	Sum of Total
500kW Mobile Generator	Generation						750,000			**750,000**
Beaver Creek Control Room Separation from Plant	Generation					137,000				**137,000**
Beaver Creek Programmable Logic Control (PLC) Upgrade	Generation					206,000	180,000			**386,000**
Beaver Creek Unit # 1 Replacement	Generation								600,000	**600,000**
Beaver Creek Unit # 2 Replacement	Generation						600,000			**600,000**
Carcross 2MVA Generation Standby Unit	Generation								3,000,000	**3,000,000**
Carmacks Fuel System Upgrade	Generation					100,000				**100,000**
Destruction Bay Compton Protection Relay Replacement and Battery Charger Upgrade	Generation	65,000								**65,000**
Destruction Bay Fuel System Upgrade	Generation					21,000				**21,000**
Destruction Bay Plant Foundation Refurbishment	Generation						150,000			**150,000**
Destruction Bay Programmable Logic Controller Upgrade	Generation							300,000		**300,000**
Destruction Bay Unit # 1 Replacement	Generation			275,000						**275,000**
Destruction Bay Unit # 2 Replacement	Generation							600,000		**600,000**
Destruction Bay Unit # 3 Replacement	Generation							450,000		**450,000**
Fish Lake Control Room Monitor Upgrade	Generation		52,000							**52,000**
Fish Lake Ditch # 3 Diversion Structure Replacement	Generation							1,640,000		**1,640,000**
Fish Lake Ditch # 3 Drop Box Concrete Upgrade	Generation			32,000	57,000					**89,000**
Fish Lake Dyke Upgrade	Generation						300,000	1,420,000		**1,720,000**
Fish Lake Dyke Widening	Generation				52,000					**52,000**
Fish Lake Head Pond # 2 Spillway Upgrade	Generation						30,000			**30,000**
Fish Lake Incremental Purchase Power	Generation		69,000							**69,000**
Fish Lake Unit # 1 Fiber Communication from Head Pond to Unit	Generation						20,000			**20,000**
Fish Lake Unit # 1 Replacement Wheel	Generation		80,000	45,000						**125,000**
Fish Lake Unit # 1 Spillway Diversion Structure	Generation						20,000	100,000		**120,000**
Fish Lake Unit # 1 Tailrace Reconstruction	Generation				173,000					**173,000**
Fish Lake Unit # 1 Turbine and Building Replacement	Generation				717,000	1,024,000	2,167,000			**3,908,000**
Fish Lake Unit # 2 Building Improvements	Generation						20,000			**20,000**
Fish Lake Unit # 2 Head Pond Low Level Outlet Pipe	Generation							30,000		**30,000**
Fish Lake Unit # 2 Penstock Improvements	Generation						40,000			**40,000**
Fish Lake Unit # 2 Penstock Replacement	Generation			486,000	70,000					**556,000**
Fish Lake Unit # 2 SCADA	Generation						50,000			**50,000**
Fish Lake Unit # 2 Siding Replacement	Generation						35,000			**35,000**
Fish Lake Unit # 2 Step-Up Transformer	Generation					172,000				**172,000**
Fish Lake Unit # 2 Turbine Inlet Valve (TIV) Replacement	Generation					171,000				**171,000**
Fish Lake Unit # 2 Vibration Monitoring	Generation						20,000			**20,000**
Fish Lake Unit #1 Generator EOL Rebuild	Generation	463,000								**463,000**
Fish Lake Unit #1 Spillway	Generation			212,000	26,000					**238,000**
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	Generation		153,000	294,000	18,000					**465,000**
Haines Junction Fuel System Upgrade	Generation					20,000				**20,000**
Haines Junction Plant Controls Upgrade	Generation		324,000		14,000					**338,000**
Haines Junction Plant Upgrades	Generation	100,000								**100,000**
High Voltage Switching Cubicle and Termination for Old Crow Plant	Generation				20,000	90,000				**110,000**
Hobo for Franklin Lake Water Monitoring	Generation				36,000					**36,000**
Hobo Water Monitor for Fish Lake at Range Road	Generation				22,000					**22,000**
Louise Lake Control Structure Gate Replacement	Generation				68,000					**68,000**
New 250kW Mobile Generator	Generation						175,000			**175,000**
Old Crow Plant Expansion	Generation						300,000	1,650,000		**1,950,000**
Old Crow Unit # 3 Replacement	Generation								500,000	**500,000**
Old Crow Unit # 4 Addition	Generation							500,000		**500,000**
Pelly Crossing Plant Automation	Generation			25,000	10,000	53,000				**88,000**
Pelly Crossing Tie into Transmission Grid	Generation	92,500								**92,500**
Purchase Unit for Pelly Crossing Power Plant	Generation			101,000	50,000					**151,000**
Ross River Fuel System Upgrade	Generation					37,000				**37,000**
Ross River Replace ABB 5HK Breakers	Generation							45,000		**45,000**
Ross River Substation Improvements	Generation				52,000					**52,000**
Ross River Unit Protection Relay	Generation				11,000					**11,000**
Stewart Crossing Plant Building Insulation	Generation							60,000		**60,000**
Stewart Crossing Plant Improvements	Generation							120,000		**120,000**
Stewart Crossing Radio Replacement and Programmable Logic Controller (PLC) Upgrade for Remote Control	Generation				30,000					**30,000**
Swift River Unit # 1 Replacement	Generation		32,000	25,000						**57,000**
Swift River Unit # 2 Replacement	Generation					53,000	30,000			**83,000**
Teslin Fuel System Upgrade	Generation					41,000				**41,000**
Teslin Plant Combustible Air Intake and Louver Improvements	Generation				19,000					**19,000**
Teslin Programmable Logic Controller (PLC) Replacement	Generation				33,000	31,000				**64,000**
Water Pressue Monitor (Hobo) for Louise Lake	Generation					37,000				**37,000**
Watson Lake Bi-Fuel Project	Generation					90,000	363,000	372,000		**825,000**
Watson Lake Generator Upgrades and Fresh Air Intakes	Generation	76,500								**76,500**
Watson Lake Protection Upgrade	Generation				48,000					**48,000**
Watson Lake Replace ABB 5HK Breakers	Generation							180,000	200,000	**380,000**
Watson Lake Unit # 1 Major Overhaul	Generation								250,000	**250,000**
Watson Lake Unit # 2 Replacement	Generation								1,350,000	**1,350,000**
Watson Lake Unit # 3 Major Overhaul	Generation					247,000				**247,000**
Watson Lake Unit # 4 Replacmenet	Generation					354,000	1,120,000			**1,474,000**
Watson Lake Unit # 5 Major Overhaul	Generation							200,000		**200,000**
Watson Lake Unit # 5 Replacement	Generation			232,000	32,000					**264,000**
Watson Lake Unit # 6 Major Overhaul	Generation						250,000			**250,000**
Grand Total		**797,000**	**710,000**	**1,727,000**	**1,558,000**	**2,884,000**	**6,620,000**	**7,667,000**	**5,900,000**	**27,863,000**

UCG-YECL-18

Reference: May 27, 2013 Application, page 4-2

Regarding diesel fuel costs, YECL states "*Price forecasts for each community are based on the current prices in place for diesel fuel at February 2013.*"

Request:

(a) Please provide details of the source for these diesel fuel prices.

(b) Please update Schedule 4.2 with the most recent diesel fuel prices and provide details of the sources for these prices.

Response:

(a) The source for these diesel fuel prices is the actual February 2013 delivered fuel expense price from fuel suppliers. This is a weighted price based on a First-in First-out inventory basis. Air North is Yukon Electrical's fuel supplier for Old Crow and Suncor Energy Products Partnership supplies fuel to all other communities.

(b) Please refer to UCG-YECL-18(b) Attachment 1. The source for these diesel fuel prices is the actual June 2013 delivered fuel expense price from fuel suppliers. This is a weighted price based on a First-in First-out inventory basis.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Fuel Information

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
	Average Cost (in cents per litre)											
1	Watson Lake		98.91	67.52	75.93	95.88	97.11	96.44	96.44	96.44	87.48	87.48
2	Beaver Creek		101.03	82.28	87.68	109.34	112.59	112.11	112.11	112.11	81.52	81.52
3	Destruction Bay		101.69	80.97	88.14	108.85	112.38	111.44	111.44	111.44	83.13	83.13
4	Old Crow		200.30	164.20	171.70	189.16	214.70	223.60	223.60	223.60	193.41	193.41
5	Pelly Crossing (Standby as of 2009)		106.10	-	-	-	-	-	-	-	89.33	89.33
6	Swift River		105.26	73.83	80.66	97.08	104.01	107.21	107.21	107.21	92.44	92.44
7	Standby Units		62.63	91.21	95.93	105.22	95.29	89.56	89.56	89.56	70.00	70.00
	Generation (MWh)											
8	Watson Lake		14,146	13,940	13,992	14,357	15,024	15,085	15,261	15,267	14,431	14,593
9	Beaver Creek		1,856	1,874	1,917	1,981	1,897	1,800	1,832	1,834	2,021	2,115
10	Destruction Bay		1,768	1,771	1,766	1,862	1,996	1,826	1,860	1,862	1,722	1,741
11	Old Crow		1,820	1,904	1,903	2,067	2,136	2,083	2,114	2,114	2,005	2,029
12	Pelly Crossing		2,203	-	-	-	-	-	-	-	1,863	11
13	Swift River		272	265	189	220	233	263	267	268	278	326
14	Standby Units		158	213	72	446	25	70	70	70	44	44
15		S.4.1 L.1	22,223	19,967	19,839	20,933	21,310	21,127	21,405	21,415	22,364	20,858
16	Net Heat Rate (kWh/litre)											
17	Watson Lake		3.82	3.81	3.85	3.74	3.80	3.78	3.78	3.78	3.82	3.82
18	Beaver Creek		3.57	3.62	3.63	3.48	3.52	3.59	3.59	3.59	3.56	3.56
19	Destruction Bay		3.29	3.58	3.44	3.56	3.68	3.58	3.58	3.58	3.41	3.41
20	Old Crow		3.43	3.40	3.62	3.58	3.45	3.60	3.60	3.60	3.56	3.56
21	Pelly Crossing		3.05	-	-	-	-	-	-	-	3.62	3.62
22	Swift River		2.96	2.99	2.51	2.73	2.77	2.79	2.79	2.79	2.99	2.99
23	Standby Units		3.00	3.00	3.00	3.35	1.50	3.02	3.02	3.02	3.50	3.50
24	Litres Consumed ('000s)											
25	Watson Lake		3,726	3,695	3,673	3,791	3,957	3,988	4,034	4,036	3,778	3,820
26	Beaver Creek		513	515	526	569	539	502	511	512	567	594
27	Destruction Bay		521	483	498	523	542	510	520	520	505	510
28	Old Crow		523	541	514	584	618	578	587	587	562	569
29	Pelly Crossing		644	-	-	-	-	-	-	-	514	3
30	Swift River		92	88	74	81	84	94	96	96	93	109
31	Standby Units		67	87	25	133	17	20	20	20	13	13
32		S.4.1 L.3	6,086	5,409	5,311	5,681	5,757	5,692	5,767	5,770	6,032	5,618

UCG-YECL-19

Reference: May 27, 2013 Application, page 4-2

YECL states "*Yukon Electrical is proposing to continue the deferral for fuel prices for the 2013-2015 test period but is requesting a change in the methodology for calculating the deferral for fuel used in Watson Lake. As a result of the conversion of the diesel units in Watson Lake to bi-fuel (diesel and LNG) beginning in the fall of 2013, generation with be based on a variable mix of diesel and LNG. This means that the forecast plant efficiency cannot be determined at this time. In order to address this issue, Yukon Electrical is requesting to use the actual equivalent diesel litres used as opposed to derived litres that are based on a forecast plant efficiency to arrive at the fuel deferral amount for Watson Lake. For all other locations, the calculation of the fuel price deferral would remain unchanged from that previously approved.*"

Request:

(a) Please confirm YECL's understanding that the Fuel Adjustment Rider & Deferred Fuel Price Variance policy (Rider F - most recently approved by the YUB in February 2012) is related to "deferring, monitoring, collecting and remitting fuel price variance amounts for diesel fuel consumed to generate electricity".

(b) Please provide details of YECL's application to the YUB regarding changing the Fuel Adjustment Rider & Deferred Fuel Price Variance policy to account for fuel prices that are not associated with diesel fuel.

(c) Please provide details of efforts by YECL to get the Yukon government to change Section 8 of the Rate Policy Directive Order in Council 1995/90 that provides for fuel price adjustments and sets out that the Board must permit YEC and YECL to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to reflect fluctuations in the prices for diesel fuel, without the requirement for specific application to and approval of the Board.

(d) Please confirm the identity and qualifications of the expert witness that YECL will put forward to speak to the industry standard conversion factors for LNG that YECL has included in its Application.

(e) Please describe details of the analysis of renewable energy alternatives that were considered in lieu of the LNG option.

(f) Has YECL had any discussions with the Yukon government regarding the development and use of natural gas deposits in the Yukon for electricity generation?

Response:

(a) Confirmed as the only fuel being used for generation by Yukon Electrical and Yukon Energy at that point in time was diesel.

(b) Yukon Electrical believes it is premature at this time to make application to the YUB regarding changing the Fuel Adjustment Rider & Deferral Price Variance Policy for the inclusion of LNG. This application contains all the necessary information for the review and testing of Yukon Electrical's proposed Fuel Price Flow Through deferral and the requested changes relating to the burning of diesel as well as LNG in Watson Lake. Once the Board has ruled on this requested deferral as part of this application, Yukon Electrical and Yukon Energy can file an updated policy that reflects the decision of the YUB.

(c) Yukon Electrical has not made any effort to get the Yukon government to change Section 8 of the Rate Policy Directive Order in Council 1995/90 that provides for fuel price adjustments and sets out that the Board must permit YEC and Yukon Electrical to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to reflect fluctuations in the prices for diesel fuel, without the requirement for specific application to and approval of the Board. That being said, Yukon Electrical is requesting a deferral for its fuel costs as part of this Application with the Yukon Utilities Board.

(d) The conversion of liters of liquefied natural gas (LNG) to diesel liters equivalent (DLE) is an industry accepted practice. As such, Yukon Electrical does not propose to provide an expert witness to participate at the hearing.

The industry accepted formula for conversion is:

LNG Volume [Diesel Litres Equivalent] = LNG Volume [Liters LNG] * Energy Content of LNG [MJ/L] / Energy Content of Diesel [MJ/L]

The energy density, the ratios of Higher and Lower Heating Value for both LNG and diesel, and the density of diesel can be found from source: U.S. Department of Energy, Center for Transportation Analysis, Biomass Energy Data Book: Edition 4. Appendix A, Conversions: Lower and Higher Heating Values of Gas, Liquid and Solid Fuels. Retrieved May 15, 2013, from http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_S olid_Fuels.pdf.

The Higher Heating Value of LNG is provided by FortisBC Energy Inc. The estimated density of LNG can be found from source: The International Group of Liquefied Natural Gas Importers, LNG Information Paper No.1. Retrieved July 24, 2013 from http://www.giignl.org/fileadmin/user_upload/pdf/LNG_Safety/1-LNG_Basics_8.28.09_Final_HQ.pdf

(e) A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed with a levelized cost of electricity estimated at 50 cents/kWh. Yukon Electrical is participating in a hydroelectric study to provide long-term renewable electricity for the Watson Lake electrical system. Yukon Electrical is participating in a geothermal energy study as an additional long term renewable alternative.

(f) No.

UCG-YECL-20

Reference: May 27, 2013 Application, page 4-2

YECL states "*Yukon Electrical's variances between actual operations and maintenance expenses and the amounts as filed were -1.9% for 2008 and 1.7% for 2009, with a total variance over the two-year test period of 0.0%. The variances between actual operations and maintenance expenses and the Board-approved amounts were -0.6% for 2008 and 7.3% for 2009, with a total variance over the two-year test period of 3.4%.*"

Request:

(a) Please confirm that YECL's 2008 and 2009 allowed O&M amounts were approved by the Board on May 21, 2009 in Order 2009-5.

(b) Please explain how the $648,000 over expenditure in 2009 was recovered / accounted for by YECL.

(c) Please provide a table showing non-fuel operating and maintenance costs per customer for 2008, 2009, 2010, 2011, 2012, 2013 (forecast), 2014 (forecast) and 2015 (forecast).

(d) Please explain the changes in labour costs and the amount of labour costs that have been transferred to capital and deferred cost projects for 2008, 2009, 2010, 2011, 2012, 2013 (forecast), 2014 (forecast) and 2015 (forecast).

(e) Please provide position titles and total compensation amounts for all positions that were compensated at more than $100,000 annually in 2008, 2009, 2010, 2011, 2012, 2013 (forecast), 2014 (forecast) and 2015 (forecast).

(f) Please confirm that the last YUB-approved revenue requirement was for 2009 and that there were no YUB-approved revenue requirements for YECL for 2010, 2011 and 2012.

(g) Please provide a table comparing the 2009 allowed O&M amounts to the actual O&M amounts in 2010, 2011 and 2012 similar to the table on page 5-2 of the Application.

(h) Please provide a table showing employee complement history by function for 2009 (Allowed), 2010 Actual, 2011 Actual, 2012 Actual, 2013 Forecast, 2014 Forecast and 2015 Forecast.

Response:

(a) Confirmed.

(b) The $648,000 higher than forecast expenditure in 2009 was recorded as an expense in 2009.

(c) Please refer to UCG-YECL-20(c) Attachment 1.

(d) Please refer to UCG-YECL-20(d) Attachment 1. The growth in labour costs is a result of the annual increases given to employees as well as the increase in the employee complement as outlined on page 1-8 of the Application. The changes in the percentage of labour costs allocated to capital are reflective of the increased capital work and focus of the Construction Department, as well changes in the types of projects completed each year and the amount of work completed using internal labour as opposed to contractors.

(e) Given the small number of personnel employed by Yukon Electrical, whose positions are well-known to the community, providing the requested information would constitute the disclosure of personal information in contravention of the *Personal Information Protection and Electronic Documents Act*. Accordingly, Yukon Electrical is not in a position to provide the requested information.

(f) Confirmed.

(g) Please refer to YUB-YECL-16 Attachment 1.

(h) Yukon Electrical does not track employee complement by function. Employees code their timesheets to the activities they have been working on in each time period, which allocates their costs to the appropriate function and/or capital project. To show employee complement by function would require Yukon Electrical to do a review of where each employee's time was coded for each time period for 2009 through 2015; and to do so would be incredibly onerous and time consuming. Yukon Electrical, however, has broken out labour expense by function. Please refer to WL-YECL-13(a) Attachment 1.

The Yukon Electrical Company Limited
Operations and Maintenance Expenses Per Customer

		2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast
Production		1,596	1,647	1,593	1,849	1,978	2,169	2,477	2,550
Distribution		2,336	2,638	2,662	2,659	3,281	3,141	3,215	3,376
General		148	142	150	141	178	159	162	165
Public Information		105	122	104	111	137	151	155	159
Customer Accounting		1,857	2,054	2,006	1,922	2,016	2,248	2,318	2,316
Administration and General		2,551	2,870	3,110	3,117	3,468	3,866	3,992	3,940
Total Operations and Maintenance Expenses	Schedule 1.1, line 9	8,593	9,474	9,625	9,799	11,059	11,735	12,319	12,507
Number of Customers	Schedule 2.1, line 45	15,339	15,596	15,884	16,272	16,702	17,028	17,306	17,597
Non-Fuel Operating and Maintenance Cost per Customer		**$ 560.23**	**$ 607.44**	**$ 605.95**	**$ 602.20**	**$ 662.13**	**$ 689.18**	**$ 711.86**	**$ 710.74**

The Yukon Electrical Company Limited
Labour Costs 2008-2015 ($000s)

Year	Gross Labour	Allocated to O&M	Allocated to Capital & Deferred Costs	Capital/Deferred %
2008	5,342	3,683	1,659	31.1%
2009	5,800	4,147	1,652	28.5%
2010	5,948	4,298	1,650	27.7%
2011	6,343	4,409	1,934	30.5%
2012	6,631	4,223	2,408	36.3%
2013	6,836	4,605	2,231	32.6%
2014	7,305	4,855	2,450	33.5%
2015	7,668	5,035	2,633	34.3%

UCG-YECL-21

Reference: May 27, 2013 Application, Schedule 5-3

YECL indicates that Governance, HR, and Health & Safety costs significantly reduced in 2012 from 2011 ($68,000) and Meter Services increased by $20,000 in 2012 over 2011.

Request:

(a) Please explain what Governance, HR, and Health & Safety services were reduced and the associated costs and explain why those cost reductions have not continued for the 2013-2015 test period.

(b) Please explain why Meter Services costs suddenly increased in 2012, the year prior to this Application's test period.

(c) Are there additional affiliate charges that are capitalized and do not show up on the O&M schedule 5-3? Please provide details of these charges for 2009 through 2015.

(d) Are there any outbound affiliate services? If yes, where are they identified?

(e) Please provide a table similar to Schedule 5-3 which includes 2009 Allowed for affiliate charges included in O&M.

(f) Please explain the differences between 2009 Allowed and the forecast amounts for 2013 through 2015.

(g) Please provide copies of service level agreements for all affiliate services provided to and by YECL in 2012 and forecast to be provided to and by YECL over the 2013-2015 test period.

(h) Please provide evidence demonstrating that it is more cost-effective to procure the services forecast for 2013-2015 from affiliates than from other sources.

Response:

(a) ATCO Electric inadvertently overcharged Yukon Electrical by approximately $40,000 for governance, HR and health & safety services in 2011, which was discovered mid-way through 2012. A true-up was recorded in 2012 for the 2011 charges. As a result, the decrease in 2011 shown on Schedule 5.3 will not continue into the 2013-2015 test period.

(b) In 2012, it was discovered that ATCO Gas had under-charged Yukon Electrical for meter services in 2010 and 2011. Yukon Electrical was not charged for this prior year under-billing. The cost incurred in 2012 is consistent with the costs incurred in 2008 and 2009.

(c) The following capital related charges related to customer care and billing from ATCO I-Tek Business Services (ITBS) were incurred or are forecast to be incurred between 2009 and 2015:

	Amount
· Credit Card Pre-Authorized Payment Plan System (included in Other Projects on page 9-17 of the Application)	$24,000
· Credit Card Pre-Authorized Payment Plan System (listed on page 9-25 of the Application; total project cost of $67,000 included other non-affiliate costs)	$45,000
· Display Change to Yukon Electrical Billing Statements (included in 2011 Demand Side Management Costs; please refer to YUB-YECL-24(b) Attachment 1)	$45,000
· Display Change to Yukon Electrical Billing Statements (described on page 9-51 of the Application)	$259,000
· E-Post Billing (described on page 9-52 of the Application)	$125,000
· New Cashier System (listed on page 9-53 of the Application)	$25,000

The following capital related information technology charges from ATCO I-Tek were incurred or forecast to be incurred from 2009-2015:

- Windows 7 Upgrades $61,000
  (listed on page 9-43 of the Application)

- Windows 7 Upgrades $146,000
  (described on page 9-51 of the Application)

(d) There are no outbound affiliate services. Please note that there are several positions, such as the General Manager and the Supervisor, Customer Accounting & Administration, that are shared between Yukon Electrical, Northland Utilities (Yellowknife) and Northland Utilities (NWT). However, these are considered allocations for which each company picks up its share of the costs based on the time dedicated to that particular company, not affiliate services.

(e) Please refer to the "GRA Approved 2009" column on Schedule 5.3 included in the Application.

(f) The services provided by affiliates are impacted by inflation (both labour and non-labour), similar to other, non-affiliates costs, resulting in overall increases in the costs of services from the 2009 approved amount to the 2013-2015 test period.

Yukon Electrical's number of customers has grown from 15,562 (approved number from 2009) to 16,702 (actual for 2012) and is forecast to grow to 17,597 by 2015. As a result of growth in the number of customers, the volume of services such as metering, after hours call answering, and billing system services has increased.

The LNG storage and vapourization costs are new in 2013, as this service was not provided in 2009.

As discussed on pages 1-9 and 1-10 of the Application, the Manager, Financial Reporting and Accounting, North of 60 and the Corporate Accountant positions were added subsequent to 2009. As well, as discussed on page 5-4 of the Application, the Supervisor of Financial Services position, which was based in Whitehorse in 2009, has been filled by an ATCO Electric employee since late

2011. These changes have resulted in the increase in Financial Reporting Support affiliate costs. Please refer to YUB-YECL-22 for further information on the need for these increases.

Costs such as information technology charges, payroll, and use of systems and IT are primarily driven by the number of employees. As Yukon Electrical's complement has grown since 2009, so has the volume of these services.

(g) Please refer to the following attachments for the requested agreements:

UCG-YECL-21(g) Attachment 1 – ATCO Electric Master Services Contract (Effective October 31, 2003)

UCG-YECL-21(g) Attachment 2 – ATCO Electric Master Services Contract Amending Agreement (Effective October 21, 2005)

UCG-YECL-21(g) Attachment 3 – ATCO Electric Master Services Contract Amending Agreement (Effective October 15, 2011)

UCG-YECL-21(g) Attachment 4 – ATCO Electric Various Services Electric Agreement (Amended March 1, 2012)

UCG-YECL-21(g) Attachment 5 – ATCO Electric Various Services Electric Agreement (Amended March 1, 2013)

UCG-YECL-21(g) Attachment 6 – ATCO Electric Project Management and Engineering Support Services Agreement (Amended December 1, 2011)

UCG-YECL-21(g) Attachment 7 – ATCO Gas Master Services Contract (Effective January 1, 2003)

UCG-YECL-21(g) Attachment 8 – ATCO Gas Meter Reading and Processing Services (Amended February 1, 2011)

UCG-YECL-21(g) Attachment 9 – ATCO Gas Meter Reading and Processing Services (Amended April 1, 2013)

UCG-YECL-21(g) Attachment 10 – ATCO Gas Office Services Agreement (Amended January 1, 2008)

UCG-YECL-21(g) Attachment 11 – ATCO I-Tek Business Services Ltd. (ITBS) Statement of Work (Amended February 13, 2009)

UCG-YECL-21(g) Attachment 12 – ATCO I-Tek Business Services Ltd. (ITBS) Customer Care and Billing Master Services Agreement (January 2010)

UCG-YECL-21(g) Attachment 13 – ATCO I-Tek Information Technology Master Services Agreement (January 2010)

UCG-YECL-21(g) Attachment 14 – ATCO Gas Energy Studies Agreement (September 2013)

UCG-YECL-21(g) Attachment 15 – ATCO Gas Liquefied Natural Gas Services Agreement (October 2013)

The forecast for affiliate service for the test years is based on the assumption that the agreements will continue through the test period as currently written.

(h) All services provided by ATCO Electric and ATCO Gas, with the exception of LNG Storage and Vaporization Skid leased at Fair Market Value, are based on a fully allocated cost methodology. No element of profit or return is included in the costs of the services. If the services were to be procured from a third party, the costs would include an element of profit to the provider, increasing the costs to Yukon Electrical.

The billing system services costs were reviewed extensively as part of the 2008-2009 GRA when Yukon Electrical brought forward the forecast costs of a new billing system. The Board accepted the costs for the new billing system as part of Board Order 2009-2. No material changes to the system or costs have occurred since that point in time.

The rates for information technology are reviewed by the Alberta Utilities Commission to ensure they are charged at fair market value.

MASTER SERVICES CONTRACT

THIS MASTER SERVICES CONTRACT DATED effective the 31 day of October, 2003.

BETWEEN:

The Yukon Electrical Company Limited, a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

Northland Utilities (NWT) Limited, a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

Northland Utilities (Yellowknife) Limited, a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "*North of 60 Companies*")

- and -

ATCO Electric Ltd., a body corporate,
incorporated under the laws of Alberta,
with offices in Edmonton, Alberta

(hereinafter referred to as "*ATCO Electric*")

WHEREAS *North of 60 Companies* desires to engage *ATCO Electric* to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

WHEREAS *ATCO Electric* has the expertise and is capable of providing the services to and for *North of 60 Companies* as described in this Contract, in accordance with the terms and conditions described in this Contract;

THIS CONTRACT WITNESSES that in consideration of the respective covenants and agreements of *North of 60 Companies* and *ATCO Electric* (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. SCHEDULES

1.1 The following Schedules are attached hereto and made a part of this Contract:

(a) Schedule A - Scope of Services - detailing the services to be provided by *ATCO Electric* to *North of 60 Companies* pursuant to this Contract (the "Services");

(b) Schedule B - Scope of Terms – detailing, if applicable:

(i) the date, if any, set for commencement of the Services by *ATCO Electric* (the "Commencement Date");

(ii) the schedule, if any, set for performance of the Services by *ATCO Electric*;

(iii) the date, if any, set for completion of the Services by *ATCO Electric* (the "Completion Date");

(iv) the term, if any, of the duration for which the Services will be provided by *ATCO Electric* (the "Term");

(v) the compensation to be paid by *North of 60 Companies* to *ATCO Electric*;

(vi) any categories of out-of-pocket expenses for which reimbursement will be payable from *North of 60 Companies* to *ATCO Electric* in accordance with Section 5.1 herein;

(vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and

(viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.

(c) Schedule C - *North of 60 Companies*'s Representative

(d) Schedule D - *ATCO Electric*'s Representative

1.2 In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

2. THE SERVICES

2.1 *North of 60 Companies* hereby engages *ATCO Electric*, and *ATCO Electric* hereby agrees to provide the Services on the terms and conditions set forth herein.

2.2 *ATCO Electric* shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at *ATCO Electric*'s own expense, subject to

Section 5.1 herein providing for reimbursement for certain identified categories of expenses.

2.3 Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.

2.4 *ATCO Electric* shall periodically, but no more frequently than monthly, furnish to *North of 60 Companies* written progress reports, when and as requested by *North of 60 Companies*.

3. TIME OF PERFORMANCE

3.1 *ATCO Electric* shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. *ATCO Electric* shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.

3.2 *ATCO Electric* shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If *ATCO Electric* determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify *North of 60 Companies* in writing.

3.3 Should *ATCO Electric*, with the prior written authorization of *North of 60 Companies*, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

4. COMPENSATION

4.1 As full consideration for performance of the Services, *North of 60 Companies* will pay *ATCO Electric* in accordance with the terms detailed in Schedule B.

4.2 In accordance with Articles 8 and 9 herein, compensation from *North of 60 Companies* shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of *ATCO Electric*.

5. EXPENSES

5.1 In accordance with Schedule B, *ATCO Electric* may also be entitled to be reimbursed by *North of 60 Companies* for reasonable out-of-pocket expenses incurred by *ATCO Electric* in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, *ATCO Electric* is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.

5.2 Any Goods and Services Tax ("G.S.T.") which is applicable to *ATCO Electric*'s reimbursable expenses shall be identified separately as a part of all invoices submitted by *ATCO Electric*.

6. INVOICING AND PAYMENT

6.1 *ATCO Electric* shall present on or before the **5th** day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by *North of 60 Companies* for the immediately prior month for Services provided pursuant to this Contract.

6.2 For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in *ATCO Electric*'s statement.

6.3 All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that *ATCO Electric* does not invoice *North of 60 Companies* for G.S.T., *ATCO Electric* shall indicate on the invoice the basis upon which *ATCO Electric* claims exemption from the statutory obligation to collect G.S.T.

6.4 All invoices shall be provided in accordance with Section 21.2 herein.

6.5 All payments are due and payable by *North of 60 Companies* **twenty-five (25)** days after receipt in *North of 60 Companies*'s offices of the invoice and any substantiating documentation required by this Contract. If *North of 60 Companies* has any objection to the invoice or substantiating documentation, it shall notify *ATCO Electric* within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by *North of 60 Companies* to *ATCO Electric* at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. *North of 60 Companies* shall be entitled to set off any mutually agreed upon amount owed by *ATCO Electric* to *North of 60 Companies* against any amount owing to *ATCO Electric*. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

7. AUDIT

7.1 This Article 7 shall only apply in the event compensation paid by *North of 60 Companies* under this Contract is based on *ATCO Electric*'s costs.

7.2 *ATCO Electric* shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with

generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.

7.3 *North of 60 Companies*, upon providing written notice to *ATCO Electric*, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. *ATCO Electric* shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to *North of 60 Companies* and its authorized representatives, and shall also make available those employees or sub-contractors of *ATCO Electric* reasonably required to supply desired information during the audit.

7.4 *North of 60 Companies* will notify *ATCO Electric* in writing of any erroneous statements made by, or payments made to, *ATCO Electric*. Subject to *ATCO Electric*'s right to have the matter determined in accordance with Article 27 herein, *ATCO Electric* will promptly make appropriate adjustments and *ATCO Electric* shall reimburse *North of 60 Companies* for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.

7.5 *ATCO Electric* shall use reasonable efforts to cause any of its sub-contractors to allow *North of 60 Companies* to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

8. INDEPENDENT CONTRACTOR

8.1 In the performance of the Services, *ATCO Electric* is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

8.2 All persons employed by *ATCO Electric* in connection with the Services shall be *ATCO Electric*'s employees and not employees of *North of 60 Companies* in any respect.

8.3 Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

9.1 *ATCO Electric* shall promptly pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any assessment or contribution required to be paid in connection

with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.

9.2 Before commencement of the Services, *ATCO Electric* will, if requested by *North of 60 Companies* deliver to *North of 60 Companies* certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by *ATCO Electric* and its sub-contractors. Before the final payment owed under this Contract is made by *North of 60 Companies*, *North of 60 Companies* may request that *ATCO Electric* deliver to *North of 60 Companies* similar certificates with *ATCO Electric*'s application for final payment from *North of 60 Companies*.

9.3 *North of 60 Companies* may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to *ATCO Electric* the amount, if any, of *ATCO Electric*'s required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where *North of 60 Companies*, in its sole discretion, determines that such amounts may be assessed against *North of 60 Companies*. Any such withholding or deduction shall not be construed as an admission by *North of 60 Companies* that *ATCO Electric* in performing the Services is an employee of *North of 60 Companies*. *North of 60 Companies* will assist *ATCO Electric* in defending any claims against *ATCO Electric* in the event that *ATCO Electric* disputes such claims.

9.4 In the event that *North of 60 Companies* does not deduct and maintain an amount sufficient to provide for *ATCO Electric*'s required assessments or contributions as specified in Section 9.3 herein, *ATCO Electric* shall indemnify and save harmless *North of 60 Companies* for any amounts assessed against and paid by *North of 60 Companies* as a result of failure by *ATCO Electric* to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.

9.5 *ATCO Electric* shall pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for *ATCO Electric*'s employees and *ATCO Electric*.

10. LIABILITY AND INDEMNIFICATION

10.1 *ATCO Electric* shall:

(a) be liable to *North of 60 Companies* for all losses, costs, damages, and expenses whatsoever which *North of 60 Companies* and *North of 60 Companies*'s directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and

(b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of *ATCO Electric*'s negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

(c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of *ATCO Electric* or its employees or sub-contractors; or

(d) *ATCO Electric* while under the direction of the Indemnified Parties.

10.2 *ATCO Electric* shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

11. INSURANCE

11.1 Without in any way limiting the liability of *ATCO Electric* under this Contract, it shall be the responsibility of *ATCO Electric* while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

(a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, **$2,000,000** inclusive, any one accident, or equivalent limits.

(b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability, owners' and contractors' protective liability, contractual liability assumed by *ATCO Electric* under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, **$5,000,000** inclusive, any one occurrence, or equivalent limits.

(c) Such other insurance as may from time to time be required by law or reasonably required by *North of 60 Companies*.

11.2 *ATCO Electric*, or contractors engaged in the provision of the Services, shall provide *North of 60 Companies* 30 days prior written notice of material changes, cancellation, or proposed lapse of their respective insurance policies.

11.3 *ATCO Electric* shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage

11.4 Upon request by *North of 60 Companies*, *ATCO Electric* shall, before commencement of the Services, deposit with *North of 60 Companies* information satisfactory to *North of 60 Companies* as evidence of the insurance required in Sections 11.1 and 11.2 herein.

12. COMPLIANCE WITH LAW AND POLICY

12.1 The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by *ATCO Electric* must be in accordance with such laws, ordinances, codes, and regulations.

12.2 *ATCO Electric* and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of *North of 60 Companies* from time to time in force which are brought to *ATCO Electric*'s notice and which are not contrary to law or the provisions of this Contract.

12.3 *ATCO Electric* shall promptly notify *North of 60 Companies* in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.

12.4 Unless otherwise specified in this Contract and subject to Section 5.1 herein, *ATCO Electric* shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

13. PUBLICITY RELEASE

13.1 *ATCO Electric* shall not, without the prior written consent of *North of 60 Companies*, use *North of 60 Companies*'s, name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

14. CONFIDENTIAL INFORMATION

14.1 The term "Confidential Information" shall mean all confidential information of or relating to *North of 60 Companies* or its business or its customers and shall include without limitation all information which *ATCO Electric* or its employees or sub-contractors, directly or indirectly, receives or acquires from *North of 60 Companies* either in writing, orally, or through observation, or which *ATCO Electric* or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or

not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

(a) information which was in the possession of *ATCO Electric* or its employees or sub-contractors, reasonable proof of which lies on *ATCO Electric*, prior to receipt or acquisition thereof from *North of 60 Companies* and which was not acquired by *ATCO Electric* or its employees or sub-contractors under any obligation of confidentiality;

(b) information which, at the time of the receipt or acquisition thereof by *ATCO Electric* or its employees or sub-contractors from ATCO, was or thereafter became a part of the public domain through no act or failure on the part of *ATCO Electric* or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and

(c) information which is disclosed to *ATCO Electric* or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to *North of 60 Companies* with respect to such information.

14.2 *ATCO Electric* and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by *North of 60 Companies* in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in *ATCO Electric*'s performance of the Services) or disclose to any third party (except as required to be disclosed by operation of law) such Confidential Information, provided that *ATCO Electric* may disclose such Confidential Information to those of *ATCO Electric*'s employees or sub-contractors to whom disclosure is required for *ATCO Electric*'s performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which *ATCO Electric* has assumed in this Article 14, and *ATCO Electric* shall ensure that all employees and sub-contractors at all times comply with such obligations.

14.3 *North of 60 Companies* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

14.4 The terms of this Article 14 shall apply, mutatis mutandis, to *North of 60 Companies*'s treatment of Confidential Information of or relating to *ATCO Electric*.

15. INTELLECTUAL PROPERTY

15.1 For the purposes of this Contract, "Intellectual Property" means

(a) all inventions, whether or not patentable,

(b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,

(c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and

(d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

15.2 All Intellectual Property made or conceived by *ATCO Electric*, its employees or sub-contractors:

(a) in the course of providing the Services;

(b) during the Term and which relates in any manner to the business of *North of 60 Companies*;

(c) made with or which arises with the use of the materials, equipment or resources of *North of 60 Companies*; and

(d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of *ATCO Electric*.

15.3 *ATCO Electric* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

16. ASSIGNMENT

16.1 With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

17. FORCE MAJEURE

17.1 For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.

17.2 Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.

17.3 In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and *North of 60 Companies* shall either:

(a) terminate this Contract, or

(b) authorize *ATCO Electric* to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

18. TERMINATION

18.1 In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.

18.2 In the event of termination pursuant to this Article 18, *ATCO Electric* shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit *ATCO Electric* to carry out its duties under this Contract. *North of 60 Companies* shall not be liable for damages or loss of anticipated profits on account of such termination.

19. REMEDIAL WORK

19.1 *ATCO Electric* shall after receipt of notice from *North of 60 Companies*, at *North of 60 Companies*'s option and at no cost to *North of 60 Companies*, without prejudice to any other right that *North of 60 Companies* might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by *ATCO Electric* in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. *North of 60 Companies* reserves the right to complete such remedial work or have such remedial work completed by other parties but at *ATCO Electric*'s expense, in the event *ATCO Electric* fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from *North of 60 Companies*.

20. WAIVER

20.1 Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

21. REPRESENTATIVES AND NOTICES

21.1 *North of 60 Companies*'s representative, who has full authority to represent *North of 60 Companies* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

ATCO Electric's representative, who has full authority to represent *ATCO Electric* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

21.2 Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

North of 60 Companies: See Schedule "C" ***ATCO Electric***: See Schedule "D"

21.3 Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

22. ENTIRETY OF AGREEMENT

22.1 This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be

provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.

22.2 There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.

22.3 No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

23. SEVERABILITY

23.1 Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

24. SURVIVAL OF TERMS

24.1 The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

25. GOVERNING LAW

25.1 The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force

from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

25.2 The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

26. INTERPRETATION

26.1 Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

26.2 In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

26.3 Where reference is made in this Contract to "*North of 60 Companies*'s affiliates", such reference shall be meant to include:

(a) an Affiliate, within the meaning of the *Business Corporations Act*, of *North of 60 Companies*; and

(b) a partnership, joint venture, or person is which *North of 60 Companies* has a controlling interest or that is otherwise subject to the control of *North of 60 Companies*.

27. DISPUTE RESOLUTION

27.1 The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of *North of 60 Companies* and *ATCO Electric*.

27.2 If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

27.3 In the event that:

(a) such dispute is not resolved pursuant to Section 27.2 above; or

(b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

28. GENERAL PROVISIONS

28.1 The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

28.2 All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

28.3 This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

28.4 Time is of the essence in the performance of every obligation of this Contract.

28.5 This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

IN WITNESS WHEREOF the Parties have duly executed this Contract with effect from the date and year first above written.

***North of 60 Companies*:**		***ATCO Electric*:**	
Per:	Paul Gogan - General Manager	Per:	
Name:		Name:	
Per:		Per:	
Name:		Name:	

North of 60 Companies Amending Agreement

WHEREAS *North of 60 Companies* and *ATCO Electric ("the Parties")* have entered into a **MASTER SERVICES CONTRACT ("MSC")** effective the 31 day of October, 2003; and

WHEREAS *North of 60 Companies* and *ATCO Electric* wish to amend that MSC,

THEREFORE the Parties covenant and agree as follows:

Clause 27.1 in the MSC is to be deleted and replaced with the following provision:

The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the Managing Director of *North of 60 Companies* and the President of *ATCO Electric*.

The Parties have duly executed this amending agreement in effect from the 21st day of October, 2005.

***North of 60 Companies*:**

Per: _____

Name: Doug Tenney

Date: October 21, 2005

***ATCO Electric*:**

Per: _____

Name: SCOTT POLICICCHIO

Date: October 27/2005

North of 60 Companies Amending Agreement

WHEREAS *North of 60 Companies* and *ATCO Electric (the Parties")* have entered into a **MASTER SERVICES CONTRACT ("MSC")** amended effective the 15th day of October, 2011; and

WHEREAS *North of 60 Companies* and *ATCO Electric* wish to amend that MSC,

THEREFORE the Parties covenant and agree as follows:

Clause 27.1 in the MSC is to be deleted and replaced with the following provision:

The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the Managing Director of *North of 60 Companies* and the President of *ATCO Electric.*

The Parties have duly executed this amending agreement in effect from the 15th day of October, 2011.

North of 60 Companies:

Per: _____

Name: B Newbb

Date: Oct 7/11

Per: _____

Name: _____

Date: Oct 12/2011

ATCO Electric:

Per: _____

Name: R.J. (Bobbi) Lambright

Date: Oct 14, 2011

Per: _____

Name: Kris Skowsley

Date: Oct 12, 11

Schedule "D" to the Master Services Contract dated • between *North of 60 Companies* and *ATCO Electric*

MASTER SERVICES CONTRACT

THIS MASTER SERVICES CONTRACT amended effective the 15th day of October, 2011.

BETWEEN:

The Yukon Electrical Company Limited, a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

Northland Utilities (NWT) Limited, a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

Northland Utilities (Yellowknife) Limited, a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "***North of 60 Companies***")

- and -

ATCO Electric Ltd., a body corporate,
incorporated under the laws of Alberta,
with offices in Edmonton, Alberta

(hereinafter referred to as "***ATCO Electric***")

WHEREAS *North of 60 Companies* desires to engage *ATCO Electric* to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

WHEREAS *ATCO Electric* has the expertise and is capable of providing the services to and for *North of 60 Companies* as described in this Contract, in accordance with the terms and conditions described in this Contract;

THIS CONTRACT WITNESSES that in consideration of the respective covenants and agreements of *North of 60 Companies* and *ATCO Electric* (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. SCHEDULES

1.1 The following Schedules are attached hereto and made a part of this Contract:

(a) Schedule A - Scope of Services - detailing the services to be provided by *ATCO Electric* to *North of 60 Companies* pursuant to this Contract (the "Services");

(b) Schedule B - Scope of Terms – detailing, if applicable:

(i) the date, if any, set for commencement of the Services by *ATCO Electric* (the "Commencement Date");

(ii) the schedule, if any, set for performance of the Services by *ATCO Electric*;

(iii) the date, if any, set for completion of the Services by *ATCO Electric* (the "Completion Date");

(iv) the term, if any, of the duration for which the Services will be provided by *ATCO Electric* (the "Term");

(v) the compensation to be paid by *North of 60 Companies* to *ATCO Electric*;

(vi) any categories of out-of-pocket expenses for which reimbursement will be payable from *North of 60 Companies* to *ATCO Electric* in accordance with Section 5.1 herein;

(vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and

(viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.

(c) Schedule C - *North of 60 Companies*'s Representative

(d) Schedule D - *ATCO Electric*'s Representative

1.2 In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

2. THE SERVICES

2.1 *North of 60 Companies* hereby engages *ATCO Electric*, and *ATCO Electric* hereby agrees to provide the Services on the terms and conditions set forth herein.

2.2 *ATCO Electric* shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at *ATCO Electric*'s own expense, subject to

Section 5.1 herein providing for reimbursement for certain identified categories of expenses.

2.3 Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.

2.4 *ATCO Electric* shall periodically, but no more frequently than monthly, furnish to *North of 60 Companies* written progress reports, when and as requested by *North of 60 Companies*.

3. TIME OF PERFORMANCE

3.1 *ATCO Electric* shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. *ATCO Electric* shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.

3.2 *ATCO Electric* shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If *ATCO Electric* determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify *North of 60 Companies* in writing.

3.3 Should *ATCO Electric*, with the prior written authorization of *North of 60 Companies*, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

4. COMPENSATION

4.1 As full consideration for performance of the Services, *North of 60 Companies* will pay *ATCO Electric* in accordance with the terms detailed in Schedule B.

4.2 In accordance with Articles 8 and 9 herein, compensation from *North of 60 Companies* shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of *ATCO Electric*.

5. EXPENSES

5.1 In accordance with Schedule B, *ATCO Electric* may also be entitled to be reimbursed by *North of 60 Companies* for reasonable out-of-pocket expenses incurred by *ATCO Electric* in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, *ATCO Electric* is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.

5.2 Any Goods and Services Tax ("G.S.T.") which is applicable to *ATCO Electric*'s reimbursable expenses shall be identified separately as a part of all invoices submitted by *ATCO Electric*.

6. INVOICING AND PAYMENT

6.1 *ATCO Electric* shall present on or before the **5th** day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by *North of 60 Companies* for the immediately prior month for Services provided pursuant to this Contract.

6.2 For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in *ATCO Electric*'s statement.

6.3 All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that *ATCO Electric* does not invoice *North of 60 Companies* for G.S.T., *ATCO Electric* shall indicate on the invoice the basis upon which *ATCO Electric* claims exemption from the statutory obligation to collect G.S.T.

6.4 All invoices shall be provided in accordance with Section 21.2 herein.

6.5 All payments are due and payable by *North of 60 Companies* **twenty-five (25)** days after receipt in *North of 60 Companies*'s offices of the invoice and any substantiating documentation required by this Contract. If *North of 60 Companies* has any objection to the invoice or substantiating documentation, it shall notify *ATCO Electric* within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by *North of 60 Companies* to *ATCO Electric* at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. *North of 60 Companies* shall be entitled to set off any mutually agreed upon amount owed by *ATCO Electric* to *North of 60 Companies* against any amount owing to *ATCO Electric*. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

7. AUDIT

7.1 This Article 7 shall only apply in the event compensation paid by *North of 60 Companies* under this Contract is based on *ATCO Electric*'s costs.

7.2 *ATCO Electric* shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with

generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.

7.3 *North of 60 Companies*, upon providing written notice to *ATCO Electric*, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. *ATCO Electric* shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to *North of 60 Companies* and its authorized representatives, and shall also make available those employees or sub-contractors of *ATCO Electric* reasonably required to supply desired information during the audit.

7.4 *North of 60 Companies* will notify *ATCO Electric* in writing of any erroneous statements made by, or payments made to, *ATCO Electric*. Subject to *ATCO Electric*'s right to have the matter determined in accordance with Article 27 herein, *ATCO Electric* will promptly make appropriate adjustments and *ATCO Electric* shall reimburse *North of 60 Companies* for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.

7.5 *ATCO Electric* shall use reasonable efforts to cause any of its sub-contractors to allow *North of 60 Companies* to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

8. INDEPENDENT CONTRACTOR

8.1 In the performance of the Services, *ATCO Electric* is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

8.2 All persons employed by *ATCO Electric* in connection with the Services shall be *ATCO Electric*'s employees and not employees of *North of 60 Companies* in any respect.

8.3 Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

9.1 *ATCO Electric* shall promptly pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any assessment or contribution required to be paid in connection

with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.

9.2 Before commencement of the Services, *ATCO Electric* will, if requested by *North of 60 Companies* deliver to *North of 60 Companies* certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by *ATCO Electric* and its sub-contractors. Before the final payment owed under this Contract is made by *North of 60 Companies*, *North of 60 Companies* may request that *ATCO Electric* deliver to *North of 60 Companies* similar certificates with *ATCO Electric*'s application for final payment from *North of 60 Companies*.

9.3 *North of 60 Companies* may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to *ATCO Electric* the amount, if any, of *ATCO Electric*'s required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where *North of 60 Companies*, in its sole discretion, determines that such amounts may be assessed against *North of 60 Companies*. Any such withholding or deduction shall not be construed as an admission by *North of 60 Companies* that *ATCO Electric* in performing the Services is an employee of *North of 60 Companies*. *North of 60 Companies* will assist *ATCO Electric* in defending any claims against *ATCO Electric* in the event that *ATCO Electric* disputes such claims.

9.4 In the event that *North of 60 Companies* does not deduct and maintain an amount sufficient to provide for *ATCO Electric*'s required assessments or contributions as specified in Section 9.3 herein, *ATCO Electric* shall indemnify and save harmless *North of 60 Companies* for any amounts assessed against and paid by *North of 60 Companies* as a result of failure by *ATCO Electric* to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.

9.5 *ATCO Electric* shall pay or cause to be paid, and *North of 60 Companies* shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for *ATCO Electric*'s employees and *ATCO Electric*.

10. LIABILITY AND INDEMNIFICATION

10.1 *ATCO Electric* shall:

(a) be liable to *North of 60 Companies* for all losses, costs, damages, and expenses whatsoever which *North of 60 Companies* and *North of 60 Companies*'s directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and

(b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of *ATCO Electric*'s negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

(c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of *ATCO Electric* or its employees or sub-contractors; or

(d) *ATCO Electric* while under the direction of the Indemnified Parties.

10.2 *ATCO Electric* shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

11. INSURANCE

11.1 Without in any way limiting the liability of *ATCO Electric* under this Contract, it shall be the responsibility of *ATCO Electric* while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

(a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, **$2,000,000** inclusive, any one accident, or equivalent limits.

(b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability, owners' and contractors' protective liability, contractual liability assumed by *ATCO Electric* under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, **$5,000,000** inclusive, any one occurrence, or equivalent limits.

(c) Such other insurance as may from time to time be required by law or reasonably required by *North of 60 Companies*.

11.2 *ATCO Electric*, or contractors engaged in the provision of the Services, shall provide *North of 60 Companies* 30 days prior written notice of material changes, cancellation, or proposed lapse of their respective insurance policies.

11.3 *ATCO Electric* shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage

11.4 Upon request by *North of 60 Companies*, *ATCO Electric* shall, before commencement of the Services, deposit with *North of 60 Companies* information satisfactory to *North of 60 Companies* as evidence of the insurance required in Sections 11.1 and 11.2 herein.

12. COMPLIANCE WITH LAW AND POLICY

12.1 The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by *ATCO Electric* must be in accordance with such laws, ordinances, codes, and regulations.

12.2 *ATCO Electric* and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of *North of 60 Companies* from time to time in force which are brought to *ATCO Electric*'s notice and which are not contrary to law or the provisions of this Contract.

12.3 *ATCO Electric* shall promptly notify *North of 60 Companies* in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.

12.4 Unless otherwise specified in this Contract and subject to Section 5.1 herein, *ATCO Electric* shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

13. PUBLICITY RELEASE

13.1 *ATCO Electric* shall not, without the prior written consent of *North of 60 Companies*, use *North of 60 Companies*'s, name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

14. CONFIDENTIAL INFORMATION

14.1 The term "Confidential Information" shall mean all confidential information of or relating to *North of 60 Companies* or its business or its customers and shall include without limitation all information which *ATCO Electric* or its employees or sub-contractors, directly or indirectly, receives or acquires from *North of 60 Companies* either in writing, orally, or through observation, or which *ATCO Electric* or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or

not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

(a) information which was in the possession of *ATCO Electric* or its employees or sub-contractors, reasonable proof of which lies on *ATCO Electric*, prior to receipt or acquisition thereof from *North of 60 Companies* and which was not acquired by *ATCO Electric* or its employees or sub-contractors under any obligation of confidentiality;

(b) information which, at the time of the receipt or acquisition thereof by *ATCO Electric* or its employees or sub-contractors from ATCO, was or thereafter became a part of the public domain through no act or failure on the part of *ATCO Electric* or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and

(c) information which is disclosed to *ATCO Electric* or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to *North of 60 Companies* with respect to such information.

14.2 *ATCO Electric* and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by *North of 60 Companies* in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in *ATCO Electric*'s performance of the Services) or disclose to any third party (except as required to be disclosed by operation of law) such Confidential Information, provided that *ATCO Electric* may disclose such Confidential Information to those of *ATCO Electric*'s employees or sub-contractors to whom disclosure is required for *ATCO Electric*'s performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which *ATCO Electric* has assumed in this Article 14, and *ATCO Electric* shall ensure that all employees and sub-contractors at all times comply with such obligations.

14.3 *North of 60 Companies* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

14.4 The terms of this Article 14 shall apply, mutatis mutandis, to *North of 60 Companies*'s treatment of Confidential Information of or relating to *ATCO Electric*.

15. INTELLECTUAL PROPERTY

15.1 For the purposes of this Contract, "Intellectual Property" means

(a) all inventions, whether or not patentable,

(b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,

(c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and

(d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

15.2 All Intellectual Property made or conceived by *ATCO Electric*, its employees or sub-contractors:

(a) in the course of providing the Services;

(b) during the Term and which relates in any manner to the business of *North of 60 Companies*;

(c) made with or which arises with the use of the materials, equipment or resources of *North of 60 Companies*; and

(d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of *ATCO Electric*.

15.3 *ATCO Electric* shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

16. ASSIGNMENT

16.1 With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

17. FORCE MAJEURE

17.1 For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.

17.2 Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.

17.3 In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and *North of 60 Companies* shall either:

(a) terminate this Contract, or

(b) authorize *ATCO Electric* to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

18. TERMINATION

18.1 In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.

18.2 In the event of termination pursuant to this Article 18, *ATCO Electric* shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit *ATCO Electric* to carry out its duties under this Contract. *North of 60 Companies* shall not be liable for damages or loss of anticipated profits on account of such termination.

19. REMEDIAL WORK

19.1 *ATCO Electric* shall after receipt of notice from *North of 60 Companies*, at *North of 60 Companies*'s option and at no cost to *North of 60 Companies*, without prejudice to any other right that *North of 60 Companies* might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by *ATCO Electric* in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. *North of 60 Companies* reserves the right to complete such remedial work or have such remedial work completed by other parties but at *ATCO Electric*'s expense, in the event *ATCO Electric* fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from *North of 60 Companies*.

20. WAIVER

20.1 Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

21. REPRESENTATIVES AND NOTICES

21.1 *North of 60 Companies*'s representative, who has full authority to represent *North of 60 Companies* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

ATCO Electric's representative, who has full authority to represent *ATCO Electric* in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

21.2 Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

North of 60 Companies: See Schedule "C" *ATCO Electric*: See Schedule "D"

21.3 Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

22. ENTIRETY OF AGREEMENT

22.1 This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be

provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.

22.2 There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.

22.3 No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

23. SEVERABILITY

23.1 Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

24. SURVIVAL OF TERMS

24.1 The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

25. GOVERNING LAW

25.1 The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force

from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

25.2 The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

26. INTERPRETATION

26.1 Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

26.2 In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

26.3 Where reference is made in this Contract to "*North of 60 Companies*'s affiliates", such reference shall be meant to include:

(a) an Affiliate, within the meaning of the *Business Corporations Act*, of *North of 60 Companies*; and

(b) a partnership, joint venture, or person is which *North of 60 Companies* has a controlling interest or that is otherwise subject to the control of *North of 60 Companies*.

27. DISPUTE RESOLUTION

27.1 The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of *North of 60 Companies* and *ATCO Electric*.

27.2 If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

27.3 In the event that:

(a) such dispute is not resolved pursuant to Section 27.2 above; or

(b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

28. GENERAL PROVISIONS

28.1 The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

28.2 All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

28.3 This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

28.4 Time is of the essence in the performance of every obligation of this Contract.

28.5 This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

IN WITNESS WHEREOF the Parties have duly executed this Contract with effect from the date and year first above written.

***North of 60 Companies*:**

Per: _____

Name: _____

Per: _____

Name: _____

***ATCO Electric*:**

Per: _____

Name: _____

Per: _____

Name: _____

YUKON ELECTRICAL COMPANY LIMITED/

ATCO ELECTRIC

VARIOUS SERVICES

Services Agreement #32

March 1, 2012

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

SCOPE OF SERVICES

ATCO Electric will make available to YECL the following services:

A. Financial Reporting Services

ATCO Electric will provide the following Financial Reporting support:

- Preparation of month end and year end accounting to Canadian Utilities
- Fixed asset administration
- Support for preparation of annual business plan
- Provide direction and supervision to the financial services department in YECL

B. Payroll Services

ATCO Electric will provide the following payroll services:

- Payroll Processing
- Employee Records Maintenance
- Reporting and Reconciliation
- Statutory Requirements and Payroll Taxes
- Benefits Administration and Reporting

Please refer to Appendix II for a detailed description of the Scope of Services.

C. Accounts Payable Services

ATCO Electric will provide the following accounts payable services:

- iExpense administration
- GST returns
- Wire transfers
- Supervision and training of YECL Accounts Payable staff.

D. Use of Systems

ATCO Electric will provide the following computer processing services:

- Monthly processing of accounting and payroll information
- Maintaining chart of accounts
- Access to and maintenance of historical information on the Oracle Financial Information System
- Use of the query software which is part of Oracle Financials
- Use of human resources systems

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

SCOPE OF SERVICES

E. Metering and Load Settlement

ATCO Electric will provide the following metering services:

- Supplying new and used meters
- Testing, verifying and re-sealing the meters
- Performing load and loss research studies

F. Health, Safety and Environment

Health, Safety and Environment (HS&E) Management System support related to the ongoing development and maintenance of YECL's HS&E Management System. Typical activities, as requested by the General Manager, would include support in:

- Identify and prioritize YECL's HS&E risks and developing management strategies
- Conduct reviews of YECL's HS&E Management System and the Safe Standards Manual to the appropriate (Yukon, Northwest Territory and British Columbia) OH&S, WCB and environmental regulatory requirements and to corporate and other requirements such as the Canadian Electricity Association, as required
- Develop, implement and provide ongoing maintenance of HS&E Best Practices and Programs in YECL's HS&E Management System and Safe Standards Manual
- Conduct evaluations and audits of YECL's HS&E Management System to identify potential improvement opportunities
- Conduct environmental compliance audits to identify regulatory and policy non-compliances and management practice non-conformances
- Research HS&E issues and conduct major incident investigations
- Provide expert assistance in the capabilities of the Safety First Software (SWMS) application
- Provide medical management through Occupational Health Services

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

SCOPE OF SERVICES

G. Corporate Communications

ATCO Electric will provide the following Corporate Communications shared services:

- ATCO Electric will include North of 60 web pages in its company intranet
- ATCO Electric will manage and execute the employee long service awards recognition program for the North of 60 companies. This includes: annual service recognition
- Communiqué (sticker program); milestone awards program; and inclusion in annual long service award banquet (every five years starting with 10 years of service).
- ATCO Electric will facilitate approval of external communications per ATCO Disclosure Policy.
- ATCO Electric will provide communications advice and counsel on selected strategic initiatives.

H. Human Resources

ATCO Electric will make available to YECL, through services provided by the Human Resources staff, the following:

- Advice and counsel on the interpretation and application of employment legislation
- Advice on and support for the implementation of corporate human resource policies and programs, including compensation and benefits, staffing and performance management, and employee relations
- Support for the negotiation and application of collective agreements
- Assistance in the recruitment, selection and orientation of employees, including preparation of internal and external advertising, coordination and conducting of interviews, assessment of candidates, and preparation of employment offers
- Coordination and administration of programs and services dealing with corporate pension and benefits plans, including Life, Health and Disability Insurance, and Pension
- Support for the implementation and administration of employee service programs including the Employee Assistance Program, Violence and Harassment-Free Workplace Program, and Disability Management Program
- Inclusion of YECL employees (less than 10 per year on average) in the long service recognition program
- General maintenance of employee earning and deduction elements at the employee level on the Oracle HRX system.
- Maintenance of annual TD1 forms for employee tax exemptions
- Maintenance of the annual Canada Savings Bond program as applicable.

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

As amended March 1, 2012

SCOPE OF SERVICES

I. Regulatory Support

The use of Regulation & Business Plan staff to support regulatory matters on an as available basis. These tasks include, but are not limited to, the following:

- Preparation of filings
- Information requests
- Witness preparation
- Consultation and Negotiations with customers
- Responses to Board requests and inquiries

The use of Electric Pricing staff to support regulatory matters on an as available basis. These tasks include, but are not limited to, the following:

- Preparation of filings
- Information requests
- Load and losses forecast
- Rate / rider design
- Cost of service
- Witness preparation
- Consultation and Negotiations with customers
- Responses to Board requests and inquiries

J. Materials Management

ATCO Electric will provide the following materials management services:

- Fill inventory requisitions submitted by YECL, from existing inventory or through the purchasing group, and arrange delivery to YECL
- Provide buying services to process requisitions into purchase orders for services or material not available through inventory
- Provide materials management consulting, for purchasing, inventory, investment recovery, warehousing and systems, education and training, on an as required basis

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

As amended March 1, 2012

SCOPE OF SERVICES

K. Information Technology

ATCO Electric will provide the following information technology support services:

- Contract support
- Resolution of service and billing issues

L. Governance

ATCO Electric senior management will provide support relating to governance, policy and strategic direction.

M. Training and Development

On an as requested and as available basis, ATCO Electric will provide training to YECL staff that is consistent in nature and scope to that provided to ATCO Electric employees.

N. Outage Call Management

ATCO Electric will provide to YECL the following After Hours Assistance (AHA) services associated with answering emergency and outage telephone calls outside of YECL's normal business hours:

- Answer outage and emergency calls received on YECL's toll free number from 6 p.m. until 9 a.m. MST Monday through Friday and 24 hours a day on weekends and on Yukon Territory statutory holidays. This service is effective December 1, 2006. Hours will be extended until 9 a.m. MST on weekdays effective April 1, 2007.
- Dispatch YECL service personnel and track their status for "working alone" until return.
- Provide a single dedicated telephone line for both outage and emergency calls with a maximum capacity of four concurrent calls in queue after which a busy signal is received.
- Provide a dedicated phone line for YECL servicemen to contact the AHA agent. Unanswered calls will receive a message to call back.
- Forward to service personnel customer requests for urgent connections or disconnections outside of YECL's regular hours of operation. Receive outage-related complaints and forward to YECL.
- Provide email hand-off of ongoing situations at commencement of normal YECL business hours.
- Priority in answering will be given to ATCO Electric calls.

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

SCOPE OF SERVICES

- Monthly reporting will be provided as follows:
  - Total number of calls answered by agents
  - Total number of calls processed by agents
  - Average Speed of Answer (daily measure)
- Answered calls will be recorded and retained for 90 days.
- Planned outages are excluded from this service. Dispatched work will not be logged. Outage messaging (TVD system) will not be provided to callers in queue.
- No dedicated emergency line for use by police, ambulance and fire departments.
- Scripting, contact lists, procedures for emergency call out of OIC, call forwarding of YECL phone lines, and hand-offs of ongoing situations at ending of YECL business hours are all the responsibility of YECL.

O. Business Continuity Management

ATCO Group Policy A-22 "Emergency Preparedness & Communication" mandates the development, exercising, maintenance and ongoing review of Emergency Response Plans (ERPs), a Crisis Management Plan (CMP) and Business Continuity Plans (BCPs) for Yukon Electrical Company Limited.

ATCO Electric will make available to YECL, through the services provided by the Business Continuity Management Program (BCMP) office, the following:

- Provide ongoing leadership, establish guidelines & standards and make recommendations toward the continuous improvement of the BCMP
- Provide consultation and assist in the development of related plans
- Assist in the facilitation and gathering of Business Impact Analysis information and other information needed for the development of BCP's
- Ensure alignment with related corporate policy, procedure, practices, and industry best practices
- Share information and promote BCM best practice with business unit leaders and ERP/BCP team leads and plan owners
- Assist in the development and as appropriate the delivery of a training program for key personnel
- Ensure that Emergency Response and Business Continuity Plans are effectively monitored, reviewed and kept up to date
- Contribute to the development, participation and facilitation of annual plan exercises

Schedule "B" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

TERMS AND CONDITIONS

1. Term of Contract

The amendments are effective as of March 1, 2012.

The term is in perpetuity with annual renewal, subject to either party giving a six-month notice to terminate. In the event that new amendments are required, an amendment agreement will be renegotiated three months prior to the effective date of the amended agreement

ATCO Electric shall provide YECL reasonable notice of changes to ATCO Electric's systems or operation of its systems that would result in material changes in the cost of the service.

2. Cost of Service Provided

The method of cost allocation and compensation to be paid by YECL to ATCO Electric will be administered in compliance with ATCO Electric's accounting policy G.5.

ATCO Electric will provide the centralized payroll service on a Cost Recovery Basis as required by the ATCO Group Inter-Affiliate Code of Conduct. For regular payroll processing services, this is currently estimated at $6 per employee per direct deposit.

The time analysis of services rendered will be reviewed a minimum of annually but may be reviewed at any time by either party with a one month notice.

The estimated cost of the services for 2012 is detailed in Appendix I.

Schedule "C" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

YECL'S REPRESENTATIVE

Dwight Redden
General Manager
100 – 1100 1st Avenue, Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-6692
dwight.redden@atco.com

Signature

Feb 21, 2012

Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

ATCO ELECTRIC'S REPRESENTATIVES

Governance
Bobbi Lambright
President, Operations Division
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7765 Fax: (780) 420-5077
bobbi.lambright@atcoelectric.com

Signature

Mar 1, 2012
Date

Financial Reporting, Payroll, Accounts Payable and Use of Systems
Barry McNabb
Vice President, Regulatory & Controller
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7604 Fax: (780) 420-8026
barry.mcnabb@atcoelectric.com

Signature

Feb 29, 2012
Date

Corporate Communications
Joanne Miller
Director, Corporate Communications
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7463 Fax: (780) 420-4199
joanne.miller@atcoelectric.com

Signature

Feb 28/12
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

ATCO ELECTRIC'S REPRESENTATIVES

Human Resources
Health, Safety & Environment
Materials Management
Training & Development
Business Continuity Management

Jerome Babyn
Vice President, Corporate Services
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-5035 Fax: (780) 420-7337
jerome.babyn@atcoelectric.com

Jerome Babyn — Signature

Feb 13/2012 — Date

Metering and Load Settlement

Satar Parhar
Senior Manager, Metering and Load Settlement
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-5501 Fax: (780) 420-3854
satar.parhar@atcoelectric.com

S. Parhar — Signature

Feb 10/2012 — Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

ATCO ELECTRIC'S REPRESENTATIVES

Regulatory Support – Phase I
James Grattan
Senior Manager, Regulatory
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 733-2489 Fax: (780) 420-7120
james.grattan@atcoelectric.com

Signature

February 10, 2012
Date

Regulatory Support – Phase II
Nick Palladino
Manager, Pricing
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7613 Fax: (780) 420-7120
nick.palladino@atcoelectric.com

Signature

February 12, 2012
Date

Information Technology
Gail Verity
Director, IT Utilization
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420- 3570Fax: (780) 508-4646
gail.verity@atcoelectric.com

Signature

February 13, 2012
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

ATCO ELECTRIC'S REPRESENTATIVES

Outage Call Management
Randy Loveseth
Senior Manager, Distribution Operations
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-3177 Fax: (780) 420-7056
randy.loveseth@atcoelectric.com

R. Loveseth
Signature

FEB. 14/2012
Date

Appendix I to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

The estimated cost of the services for 2012 is as follows:

Financial Reporting, Accounts Payable, Use of Systems	$ 225,000
Regulatory Support (Note 1)	$ 20,000
Payroll Services (Note 2)	$11,000
Metering and Load Settlement	$ 47,000
Health, Safety and Environment	$ 26,000
Corporate Communications	$ 8,000
Human Resources	$ 99,000
Materials Management	$ 49,000
Information Technology	$ 1,000
Governance	$ 29,000
Training and Development	$ 11,000
Outage Call Management	$ 33,000
Business Continuity Management	$ 10,000
Total	$569,000

Note 1: This estimate excludes costs associated with Phase I and Phase II Regulatory Matters as the scope and quantity of work associated with these matters have yet to be determined.

Note 2: Payroll Services are estimated at $6 per employee per pay.

Appendix II to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2012

This agreement states that ATCO Electric will provide services for the administration and coordination of Payroll Services as required by YECL. Functions and activities include:

1) Payroll Processing

- Production of employee pay advices on a bi-weekly basis. Ensure that employees are paid accurately and any adjustments are made in a timely fashion.
- Set up and maintenance of automatic payroll deposits to employee bank accounts.
- Maintain controls to ensure employees are paid correctly.
- Processing and reporting of bonuses and severance payments ensuring that all auditing and governmental requirements are met.
- Distribute pay advises to locations defined and maintained by YECL.

2) Employee Records Maintenance

- Set up and maintain the system payroll schedule and global tables.
- Maintenance of employee information on payroll system such as preset distribution and taxing information.

3) Reporting and Reconciliation

- Reconcile payroll clearing and control accounts based on general ledger information provided by YECL and provide completed reconciliations to YECL following each payroll run.
- Distribute appropriate reports.

4) Statutory Requirements and Payroll Taxes

- Payment and reconciliation of employee and employer source deductions to the Federal Government for the standard and lower rates of Employment Insurance.
- Preparation of yearly source deductions summary for submission to Federal Government. Reconcile year end financial controls to T4 summary and determine appropriate adjustments when applicable.
- Preparation of annual T4s for employees including all taxable benefits (such as parking, market differential loans, severance payments, bonuses, etc.). Preparation of annual T4As for non-employees such as pensioners, bursary recipients and directors as required.
- Preparation of assessable earning reports for submission to WCB by YECL.
- Payment of Alberta Health Care premiums as necessary and account reconciliation.
- Processing and reporting of non-resident taxes (NR4) when applicable.
- Process third party demands such as maintenance enforcement payments and wage garnishments.

5) Benefits Administration and Reporting

- ATCO Flex group benefit payment and account reconciliation. Ensure that prepayment of benefits for employees taking an unpaid leave of absence (for educational purposes or parental leave, for example) are processed correctly.

YUKON ELECTRICAL COMPANY LIMITED/
ATCO ELECTRIC
VARIOUS SERVICES
Services Agreement #32
March 1, 2013

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

SCOPE OF SERVICES

ATCO Electric will make available to YECL the following services:

A. Financial Reporting Services

ATCO Electric will provide the following Financial Reporting support:

- Preparation of month end and year end accounting to Canadian Utilities
- Fixed asset administration
- Support for preparation of annual business plan
- Provide direction and supervision to the financial services department in YECL

B. Payroll Services

ATCO Electric will provide the following payroll services:

- Payroll Processing
- Employee Records Maintenance
- Reporting and Reconciliation
- Statutory Requirements and Payroll Taxes
- Benefits Administration and Reporting

Please refer to Appendix II for a detailed description of the Scope of Services.

C. Accounts Payable Services

ATCO Electric will provide the following accounts payable services:

- iExpense administration
- GST returns
- Wire transfers
- Training of YECL Accounts Payable staff.
- Processing and reporting of non-resident taxes (NR4) when applicable.

D. Use of Systems

ATCO Electric will provide the following computer processing services:

- Monthly processing of accounting and payroll information
- Maintaining chart of accounts
- Access to and maintenance of historical information on the Oracle Financial Information System
- Use of the query software which is part of Oracle Financials
- Use of human resources systems

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

SCOPE OF SERVICES

E. Metering and Load Settlement

ATCO Electric will provide the following metering services:

- Supplying new and used meters
- Testing, verifying and re-sealing the meters
- Performing load and loss research studies

F. Health, Safety and Environment

Health, Safety and Environment (HS&E) Management System support related to the ongoing development and maintenance of YECL's HS&E Management System. Typical activities, as requested by the General Manager, would include support in:

- Identify and prioritize YECL's HS&E risks and developing management strategies
- Conduct reviews of YECL's HS&E Management System and the Safe Standards Manual to the appropriate (Yukon, Northwest Territory and British Columbia) OH&S, WCB and environmental regulatory requirements and to corporate and other requirements such as the Canadian Electricity Association, as required
- Develop, implement and provide ongoing maintenance of HS&E Best Practices and Programs in YECL's HS&E Management System and Safe Standards Manual
- Conduct evaluations and audits of YECL's HS&E Management System to identify potential improvement opportunities
- Conduct environmental and safety compliance audits to identify regulatory and policy non-compliances and management practice non-conformances
- Research HS&E issues and conduct major incident investigations
- Provide expert assistance in the capabilities of the Safety First Software (SWMS) application
- Provide medical management through Occupational Health Services

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

SCOPE OF SERVICES

G. Corporate Communications

ATCO Electric will provide the following Corporate Communications shared services:

- ATCO Electric will include North of 60 web pages in its company intranet
- ATCO Electric will manage and execute the employee long service awards recognition program for the North of 60 companies. This includes: annual service recognition
- Communiqué (sticker program); milestone awards program; and inclusion in annual long service award banquet (every five years starting with 10 years of service).
- ATCO Electric will facilitate approval of external communications per ATCO Disclosure Policy.
- ATCO Electric will provide communications advice and counsel on selected strategic initiatives.

H. Human Resources

ATCO Electric will make available to YECL, through services provided by the Human Resources staff, the following:

- Advice and counsel on the interpretation and application of employment legislation
- Advice on and support for the implementation of corporate human resource policies and programs, including compensation and benefits, staffing and performance management, and employee relations
- Support for the negotiation and application of collective agreements
- Assistance in the recruitment, selection and orientation of employees, including preparation of internal and external advertising, coordination and conducting of interviews, assessment of candidates, and preparation of employment offers
- Coordination and administration of programs and services dealing with corporate pension and benefits plans, including Life, Health and Disability Insurance, and Pension
- Support for the implementation and administration of employee service programs including the Employee Assistance Program, Violence and Harassment-Free Workplace Program, and Disability Management Program
- Inclusion of YECL employees (less than 10 per year on average) in the long service recognition program
- General maintenance of employee earning and deduction elements at the employee level on the Oracle HRX system.
- Maintenance of annual TD1 forms for employee tax exemptions
- Maintenance of the annual Canada Savings Bond program as applicable.

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

As amended March 1, 2013

SCOPE OF SERVICES

- Maintenance of employee information on payroll system such as preset distribution and taxing information.
- Set up and maintenance of automatic payroll deposits to employee bank accounts

I. Regulatory Support

The use of Regulation & Business Plan staff to support regulatory matters on an as available basis. These tasks include, but are not limited to, the following:

- Preparation of filings
- Information requests
- Witness preparation
- Consultation and Negotiations with customers
- Responses to Board requests and inquiries

The use of Electric Pricing staff to support regulatory matters on an as available basis. These tasks include, but are not limited to, the following:

- Preparation of filings
- Information requests
- Load and losses forecast
- Rate / rider design
- Cost of service
- Witness preparation
- Consultation and Negotiations with customers
- Responses to Board requests and inquiries

J. Supply Chain Management

ATCO Electric will provide the following supply chain management services:

- Fill inventory requisitions submitted by YECL, from existing inventory or through the purchasing group, and arrange delivery to YECL
- Provide buying services to process requisitions into purchase orders for services or material not available through inventory
- Provide supply chain management consulting, for purchasing, inventory, investment recovery, warehousing and systems, education and training, on an as required basis

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

As amended March 1, 2013

SCOPE OF SERVICES

K. Information Technology

ATCO Electric will provide the following information technology support services:

- Contract support
- Resolution of service and billing issues

L. Governance

ATCO Electric senior management will provide support relating to governance, policy and strategic direction.

M. Training and Development

On an as requested and as available basis, ATCO Electric will provide training to YECL staff that is consistent in nature and scope to that provided to ATCO Electric employees.

N. Outage Call Management

ATCO Electric will provide to YECL the following Outage Call Management (OCM) services associated with answering emergency and outage telephone calls outside of YECL's normal business hours:

- Answer outage and emergency calls received on YECL's toll free number from 6 p.m. until 9 a.m. MST Monday through Friday and 24 hours a day on weekends and on Yukon Territory statutory holidays. This service is effective December 1, 2006. Hours will be extended until 9 a.m. MST on weekdays effective April 1, 2007.
- Dispatch YECL service personnel and track their status for "working alone" until return.
- Provide a single dedicated telephone line for both outage and emergency calls with a maximum capacity of four concurrent calls in queue after which a busy signal is received.
- Provide a dedicated phone line for YECL servicemen to contact the OCM agent. Unanswered calls will receive a message to call back.
- Forward to service personnel customer requests for urgent connections or disconnections outside of YECL's regular hours of operation. Receive outage-related complaints and forward to YECL.
- Provide email hand-off of ongoing situations at commencement of normal YECL business hours.
- Priority in answering will be given to ATCO Electric calls.

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

SCOPE OF SERVICES

- Monthly reporting will be provided as follows:
  - Total number of calls answered by agents
  - Total number of calls processed by agents
  - Average Speed of Answer (daily measure)
- Answered calls will be recorded and retained for 90 days.
- Planned outages are excluded from this service. Dispatched work will not be logged. Outage messaging (TVD system) will not be provided to callers in queue.
- No dedicated emergency line for use by police, ambulance and fire departments.
- Scripting, contact lists, procedures for emergency call out of OIC, call forwarding of YECL phone lines, and hand-offs of ongoing situations at ending of YECL business hours are all the responsibility of YECL.

O. Business Continuity Management

ATCO Group Policy A-22 "Emergency Preparedness & Communication" mandates the development, exercising, maintenance and ongoing review of Emergency Response Plans (ERPs), a Crisis Management Plan (CMP) and Business Continuity Plans (BCPs) for Yukon Electrical Company Limited.

ATCO Electric will make available to YECL, through the services provided by the Business Continuity Management Program (BCMP) office, the following:

- Provide ongoing leadership, establish guidelines & standards and make recommendations toward the continuous improvement of the BCMP
- Provide consultation and assist in the development of related plans
- Assist in the facilitation and gathering of Business Impact Analysis information and other information needed for the development of BCP's
- Ensure alignment with related corporate policy, procedure, practices, and industry best practices
- Share information and promote BCM best practice with business unit leaders and ERP/BCP team leads and plan owners
- Assist in the development and as appropriate the delivery of a training program for key personnel
- Ensure that Emergency Response and Business Continuity Plans are effectively monitored, reviewed and kept up to date
- Contribute to the development, participation and facilitation of annual plan exercises and reviews

Schedule "A" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

SCOPE OF SERVICES

P. Building Construction and Facility Maintenance

On an as requested and as available basis, ATCO Electric will provide support for Northland Utilities that is consistent in nature and scope to that provided to ATCO Electric related to building construction and facilities maintenance.

Schedule "B" to the Master Service Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

TERMS AND CONDITIONS

1. Term of Contract

The amendments are effective as of March 1, 2013.

The term is in perpetuity with annual renewal, subject to either party giving a six-month notice to terminate. In the event that new amendments are required, an amendment agreement will be renegotiated three months prior to the effective date of the amended agreement

ATCO Electric shall provide YECL reasonable notice of changes to ATCO Electric's systems or operation of its systems that would result in material changes in the cost of the service.

2. Cost of Service Provided

The method of cost allocation and compensation to be paid by YECL to ATCO Electric will be administered in compliance with ATCO Electric's accounting policy G.5.

ATCO Electric will provide the centralized payroll service on a Cost Recovery Basis as required by the ATCO Group Inter-Affiliate Code of Conduct. For regular payroll processing services, this is currently estimated at $6 per employee per direct deposit.

The time analysis of services rendered will be reviewed a minimum of annually but may be reviewed at any time by either party with a one month notice.

The estimated cost of the services for 2013 is detailed in Appendix I.

Schedule "C" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

YECL'S REPRESENTATIVE

Dwight Redden
General Manager
100 – 1100 1st Avenue, Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-6692
dwight.redden@atco.com

Signature

FEBRUARY 25, 2013

Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Governance
Bobbi Lambright
President, Operations Division
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7765 Fax: (780) 420-5077
bobbi.lambright@atcoelectric.com

Signature

Mar 1, 2013
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

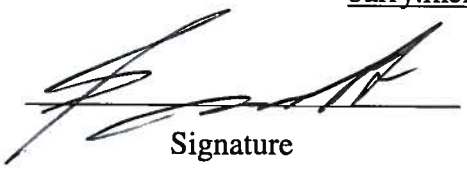
Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Financial Reporting, Payroll, Accounts Payable and Use of Systems

Barry McNabb
Vice President, Regulatory & Controller
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7604 Fax: (780) 420-8026
barry.mcnabb@atcoelectric.com



Signature

Feb 25, 2013

Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Corporate Communications
Joanne Miller
Director, Corporate Communications
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7463 Fax: (780) 420-4199
joanne.miller@atcoelectric.com

Signature

Feb 28/13
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Human Resources
Health, Safety & Environment
Supply Chain Management
Training & Development
Business Continuity Management
Building Construction & Facility Maintenance

Jerome Babyn
Vice President, Corporate Services
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-5035 Fax: (780) 420-7337
jerome.babyn@atcoelectric.com

Jerome Babyn
Signature

Feb 28/13
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Metering and Load Settlement
Bob Deyl
Manager, Metering and Load Settlement
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-5501 Fax: (780) 420-3854
bob.deyl@atcoelectric.com

Signature

Feb 28, 2013
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Regulatory Support – Phase I

James Grattan
Senior Manager, Regulatory
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 733-2489 Fax: (780) 420-7120
james.grattan@atcoelectric.com

Signature

February 26, 2013.
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Regulatory Support – Phase II

Satar Parhar
Senior Manager, Pricing
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7613 Fax: (780) 420-7120
satar.parhar@atcoelectric.com

S. Parhar — Signature

Feb 25/2013 — Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Information Technology
Maureen Lang
Senior Manager, Business and Technology Solutions
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-7164 Fax: (780) 508-4646
maureen.lang@atcoelectric.com

M Lang
Signature

2/27/13
Date

Schedule "D" to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

ATCO ELECTRIC'S REPRESENTATIVES

Outage Call Management
Randy Loveseth
Senior Manager, Distribution Operations
10035–105 Street, Edmonton, Alberta T5J 2V6
Telephone: (780) 420-3177 Fax: (780) 420-7056
randy.loveseth@atcoelectric.com

R. Loveseth
Signature

FEBRUARY 27, 2013
Date

Appendix I to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

The estimated cost of the services for 2013 is as follows:

Financial Reporting, Accounts Payable, Use of Systems	$ 586,000
Regulatory Support (Note 1)	$ 10,000
Payroll Services (Note 2)	$11,000
Metering and Load Settlement	$ 49,000
Health, Safety and Environment	$ 6,800
Human Resources	$ 99,000
Supply Chain Management	$ 76,400
Information Technology	$ 3,500
Governance	$ 15,000
Outage Call Management	$ 62,000
Business Continuity Management	$ 7,500
Building Construction and Facility Maintenance	$ 10,000
Total	$936,200

Note 1: This estimate excludes costs associated with Phase I and Phase II Regulatory Matters as the scope and quantity of work associated with these matters have yet to be determined.

Note 2: Payroll Services are estimated at $6 per employee per pay.

Appendix II to the Master Services Contract

VARIOUS SERVICES

dated October 31, 2003 between

Yukon Electrical Company Limited ("YECL") and ATCO Electric

as amended March 1, 2013

This agreement states that ATCO Electric will provide services for the administration and coordination of Payroll Services as required by YECL. Functions and activities include:

1) **Payroll Processing**
   - Production of employee pay advices on a bi-weekly basis. Ensure that employees are paid accurately and any adjustments are made in a timely fashion.
   - Maintain controls to ensure employees are paid correctly.
   - Processing and reporting of bonuses and severance payments ensuring that all auditing and governmental requirements are met.
   - Distribute pay advices to locations defined and maintained by YECL.

2) **Employee Records Maintenance**
   - Set up and maintain the system payroll schedule and global tables.

3) **Reporting and Reconciliation**
   - Reconcile payroll clearing and control accounts based on general ledger information provided by YECL and provide completed reconciliations to YECL following each payroll run.
   - Distribute appropriate reports.

4) **Statutory Requirements and Payroll Taxes**
   - Payment and reconciliation of employee and employer source deductions to the Federal Government for the standard and lower rates of Employment Insurance.
   - Preparation of yearly source deductions summary for submission to Federal Government. Reconcile year end financial controls to T4 summary and determine appropriate adjustments when applicable.
   - Preparation of annual T4s for employees including all taxable benefits (such as parking, market differential loans, severance payments, bonuses, etc.). Preparation of annual T4As for non-employees such as pensioners, bursary recipients and directors as required.
   - Preparation of assessable earning reports for submission to WCB by YECL.
   - Payment of Health Care premiums as necessary and account reconciliation.
   - Process third party demands such as maintenance enforcement payments and wage garnishments.

5) **Benefits Administration and Reporting**
   - ATCO Flex group benefit payment and account reconciliation. Ensure that prepayment of benefits for employees taking an unpaid leave of absence (for educational purposes or parental leave, for example) are processed correctly.

NORTH OF 60 COMPANIES

(NORTHLAND UTILITIES (NWT) LIMITED,

NORTHLAND UTLITIES (YELLOWKNIFE) LIMITED,

THE YUKON ELECTRICAL COMPANY LIMITED)

and ATCO ELECTRIC

PROJECT MANAGEMENT AND ENGINEERING SUPPORT SERVICES

Services Agreement #75

Amended as of December 1, 2011

Schedule "A" to the Master Services Contract

PROJECT MANAGEMENT AND ENGINEERING SUPPORT SERVICES

dated February 15, 2011 between

North of 60 Companies and ATCO Electric

Amended as of December 1, 2011

SCOPE OF SERVICES

ATCO Electric will provide the following services to the North of 60 Companies on an as available, as needed, basis:

1. Transmission Engineering – planning, analysis, engineering and technical consultation, design and evaluation of transmission substation primary and secondary systems, power lines, and telecommunication systems to be undertaken on an ad hoc, as required, basis or in association with projects agreed to be undertaken by ATCO Electric under the terms of this agreement.

2. Distribution Engineering – planning, analysis, engineering and technical consultation, and design and evaluation of distribution power systems to be undertaken on an ad hoc, as required, basis or in association with projects agreed to be undertaken by ATCO Electric under the terms of this agreement.

3. Maintenance Management and Engineering – analysis, engineering, and technical support relating to the performance and maintenance of power systems and associated individual assets to be undertaken on an ad hoc, as required, basis or in association with projects agreed to be undertaken by ATCO Electric under the terms of this agreement.

4. Project Management services – coordination, cost estimating and management, risk management, and scheduling of individual projects agreed to be undertaken by ATCO Electric in accordance with this agreement.

5. Materials procurement – specification, procurement and expediting of materials requirements specific to projects undertaken by ATCO Electric under the terms of this agreement.

6. Construction, construction management, and commissioning – construction and commissioning of transmission, distribution or telecommunication system related projects specifically undertaken by ATCO Electric under the terms of this agreement.

In providing these services, ATCO Electric may use internal resources in either the Operating or Capital Divisions, or may utilize contract services as required.

Schedule "B" to the Master Services Contract

PROJECT MANAGEMENT AND ENGINEERING SUPPORT SERVICES

dated February 15, 2011 between

North of 60 Companies and ATCO Electric

Amended as of December 1, 2011

TERMS AND CONDITIONS

1. Term of Contract

This amending agreement is effective as of December 1, 2011.

The term is in perpetuity with annual renewal, subject to either party providing three months' written notice to terminate. In the event that new amendments are required, a new agreement will be negotiated three months prior to the effective date of the amending agreement.

ATCO Electric shall provide the North of 60 Companies with reasonable notice of changes to ATCO Electric's systems or operation of its systems that would result in material changes in the cost of the service.

2. Cost of Service Provided

The method of cost allocation and compensation to be paid by the North of 60 Companies to ATCO Electric will be administered in compliance with ATCO Electric's accounting policy G5.

Schedule "C" to the Master Services Contract

PROJECT MANAGEMENT AND ENGINEERING SUPPORT SERVICES

dated February 15, 2011 between

North of 60 Companies and ATCO Electric

Amended as of December 1, 2011

NORTH OF 60 COMPANIES' REPRESENTATIVE

Dwight Redden
General Manager
100 – 1100 1st Avenue,
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-6692
Email: dwight.redden@atco.com

Signature

Nov 25, 2011
Date

Schedule "D" to the Master Services Contract

PROJECT MANAGEMENT AND ENGINEERING SUPPORT SERVICES

dated February 15, 2011 between

North of 60 Companies and ATCO Electric

Amended as of December 1, 2011

ATCO ELECTRIC'S REPRESENTATIVE

Kris Sakowsky
Vice President, Engineering and Construction
10035 - 105 Street
Edmonton, AB T5J 2V6
Telephone: (780) 420-7082
Fax: (780) 420-7700
Email: kris.sakowsky@atcoelectric.com

Signature

Nov 29, 2011
Date

Tom McGhan, P. Eng.
Vice President, Contracting, Procurement & Transmission Capital
10035 - 105 Street
Edmonton, AB T5J 2V6
Telephone: (780) 420-3958
Email: tom.mcghan@atcoelectric.com

Signature

Nov 28, 2011
Date

MASTER SERVICES CONTRACT

THIS MASTER SERVICES CONTRACT DATED effective the 1st day of January, 2003.

BETWEEN:

THE YUKON ELECTRICAL COMPANY LIMITED,
a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

NORTHLAND UTILITIES (NWT) LIMITED,
a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

NORTHLAND UTILTIES (YELLOWKNIFE) LIMITED,
a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "**North of 60 Companies**")

- and -

ATCO GAS, an operating name of
ATCO Gas and Pipelines Limited,
with offices in Edmonton and Calgary, Alberta

(hereinafter referred to as "**ATCO Gas**")

WHEREAS North of 60 Companies desires to engage ATCO Gas to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

WHEREAS ATCO Gas has the expertise and is capable of providing the services to and for North of 60 Companies as described in this Contract, in accordance with the terms and conditions described in this Contract;

THIS CONTRACT WITNESSES that in consideration of the respective covenants and agreements of North of 60 Companies and ATCO Gas (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable

consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. SCHEDULES

1.1 The following Schedules are attached hereto and made a part of this Contract:

(a) Schedule A - Scope of Services - detailing the services to be provided by ATCO Gas to North of 60 Companies pursuant to this Contract (the "Services");

(b) Schedule B - Scope of Terms – detailing, if applicable:

(i) the date, if any, set for commencement of the Services by ATCO Gas (the "Commencement Date");

(ii) the schedule, if any, set for performance of the Services by ATCO Gas;

(iii) the date, if any, set for completion of the Services by ATCO Gas (the "Completion Date");

(iv) the term, if any, of the duration for which the Services will be provided by ATCO Gas (the "Term");

(v) the compensation to be paid by North of 60 Companies to ATCO Gas;

(vi) any categories of out-of-pocket expenses for which reimbursement will be payable from North of 60 Companies to ATCO Gas in accordance with Section 5.1 herein;

(vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and

(viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.

(c) Schedule C - North of 60 Companies' Representative

(d) Schedule D - ATCO Gas' Representative

1.2 In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

2. THE SERVICES

2.1 North of 60 Companies hereby engages ATCO Gas, and ATCO Gas hereby agrees to provide the Services on the terms and conditions set forth herein.

2.2 ATCO Gas shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at ATCO Gas' own expense, subject to Section 5.1 herein providing for reimbursement for certain identified categories of expenses.

2.3 Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.

2.4 ATCO Gas shall periodically, but no more frequently than monthly, furnish to North of 60 Companies written progress reports, when and as requested by North of 60 Companies.

3. TIME OF PERFORMANCE

3.1 ATCO Gas shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. ATCO Gas shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.

3.2 ATCO Gas shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If ATCO Gas determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify North of 60 Companies in writing.

3.3 Should ATCO Gas, with the prior written authorization of North of 60 Companies, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

4. COMPENSATION

4.1 As full consideration for performance of the Services, North of 60 Companies will pay ATCO Gas in accordance with the terms detailed in Schedule B.

4.2 In accordance with Articles 8 and 9 herein, compensation from North of 60 Companies shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of ATCO Gas.

5. EXPENSES

5.1 In accordance with Schedule B, ATCO Gas may also be entitled to be reimbursed by North of 60 Companies for reasonable out-of-pocket expenses incurred by ATCO Gas in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, ATCO Gas is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.

5.2 Any Goods and Services Tax ("G.S.T.") which is applicable to ATCO Gas' reimbursable expenses shall be identified separately as a part of all invoices submitted by ATCO Gas.

6. INVOICING AND PAYMENT

6.1 ATCO Gas shall present on or before the 5th day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by North of 60 Companies for the immediately prior month for Services provided pursuant to this Contract.

6.2 For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in ATCO Gas' statement.

6.3 All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that ATCO Gas does not invoice North of 60 Companies for G.S.T., ATCO Gas shall indicate on the invoice the basis upon which ATCO Gas claims exemption from the statutory obligation to collect G.S.T.

6.4 All invoices shall be provided in accordance with Section 21.2 herein.

6.5 All payments are due and payable by North of 60 Companies **twenty-five (25)** days after receipt in North of 60 Companies' offices of the invoice and any substantiating documentation required by this Contract. If North of 60 Companies has any objection to the invoice or substantiating documentation, it shall notify ATCO Gas within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by North of 60 Companies to ATCO Gas at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. North of 60 Companies shall be entitled to set off any mutually agreed upon amount owed by ATCO Gas to North of 60 Companies against any amount owing

to ATCO Gas. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

7. AUDIT

7.1 This Article 7 shall only apply in the event compensation paid by North of 60 Companies under this Contract is based on ATCO Gas' costs.

7.2 ATCO Gas shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.

7.3 North of 60 Companies, upon providing written notice to ATCO Gas, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. ATCO Gas shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to North of 60 Companies and its authorized representatives, and shall also make available those employees or sub-contractors of ATCO Gas reasonably required to supply desired information during the audit.

7.4 North of 60 Companies will notify ATCO Gas in writing of any erroneous statements made by, or payments made to, ATCO Gas. Subject to ATCO Gas' right to have the matter determined in accordance with Article 27 herein, ATCO Gas will promptly make appropriate adjustments and ATCO Gas shall reimburse North of 60 Companies for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.

7.5 ATCO Gas shall use reasonable efforts to cause any of its sub-contractors to allow North of 60 Companies to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

8. INDEPENDENT CONTRACTOR

8.1 In the performance of the Services, ATCO Gas is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

8.2 All persons employed by ATCO Gas in connection with the Services shall be ATCO Gas' employees and not employees of North of 60 Companies in any respect.

8.3 Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

9.1 ATCO Gas shall promptly pay or cause to be paid, and North of 60 Companies shall not be responsible for, any assessment or contribution required to be paid in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.

9.2 Before commencement of the Services, ATCO Gas will, if requested by North of 60 Companies deliver to North of 60 Companies certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by ATCO Gas and its sub-contractors. Before the final payment owed under this Contract is made by North of 60 Companies, North of 60 Companies may request that ATCO Gas deliver to North of 60 Companies similar certificates with ATCO Gas' application for final payment from North of 60 Companies.

9.3 North of 60 Companies may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to ATCO Gas the amount, if any, of ATCO Gas' required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where North of 60 Companies, in its sole discretion, determines that such amounts may be assessed against North of 60 Companies. Any such withholding or deduction shall not be construed as an admission by North of 60 Companies that ATCO Gas in performing the Services is an employee of North of 60 Companies. North of 60 Companies will assist ATCO Gas in defending any claims against ATCO Gas in the event that ATCO Gas disputes such claims.

9.4 In the event that North of 60 Companies does not deduct and maintain an amount sufficient to provide for ATCO Gas' required assessments or contributions as specified in Section 9.3 herein, ATCO Gas shall indemnify and save harmless North of 60 Companies for any amounts assessed against and paid by North of 60 Companies as a result of failure by ATCO Gas to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.

9.5 ATCO Gas shall pay or cause to be paid, and North of 60 Companies shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding

taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for ATCO Gas' employees and ATCO Gas.

10. LIABILITY AND INDEMNIFICATION

10.1 ATCO Gas shall:

(a) be liable to North of 60 Companies for all losses, costs, damages, and expenses whatsoever which North of 60 Companies and North of 60 Companies' directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and

(b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of ATCO Gas' negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

(c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of ATCO Gas or its employees or sub-contractors; or

(d) ATCO Gas while under the direction of the Indemnified Parties.

10.2 ATCO Gas shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

11. INSURANCE

11.1 Without in any way limiting the liability of ATCO Gas under this Contract, it shall be the responsibility of ATCO Gas while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

(a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, $2,000,000 inclusive, any one accident, or equivalent limits.

(b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability,

owners' and contractors' protective liability, contractual liability assumed by ATCO Gas under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, $5,000,000 inclusive, any one occurrence, or equivalent limits.

(c) Such other insurance as may from time to time be required by law or reasonably required by North of 60 Companies.

11.2 ATCO Gas, or contractors engaged in the provision of the Services, shall provide North of 60 Companies with 30 days prior written notice of any material changes, proposed cancellation or reduction in coverage, or proposed lapse of their respective insurance policies.

11.3 ATCO Gas shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage

11.4 Upon request by North of 60 Companies, ATCO Gas shall, before commencement of the Services, deposit with North of 60 Companies information satisfactory to North of 60 Companies as evidence of the insurance required in Sections 11.1 and 11.2 herein.

12. COMPLIANCE WITH LAW AND POLICY

12.1 The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by ATCO Gas must be in accordance with such laws, ordinances, codes, and regulations.

12.2 ATCO Gas and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of North of 60 Companies from time to time in force which are brought to ATCO Gas' notice and which are not contrary to law or the provisions of this Contract.

12.3 ATCO Gas shall promptly notify North of 60 Companies in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.

12.4 Unless otherwise specified in this Contract and subject to Section 5.1 herein, ATCO Gas shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

13. PUBLICITY RELEASE

13.1 ATCO Gas shall not, without the prior written consent of North of 60 Companies, use North of 60 Companies', name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

14. CONFIDENTIAL INFORMATION

14.1 The term "Confidential Information" shall mean all confidential information of or relating to North of 60 Companies or its business or its customers and shall include without limitation all information which ATCO Gas or its employees or sub-contractors, directly or indirectly, receives or acquires from North of 60 Companies either in writing, orally, or through observation, or which ATCO Gas or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

(a) information which was in the possession of ATCO Gas or its employees or sub-contractors, reasonable proof of which lies on ATCO Gas, prior to receipt or acquisition thereof from North of 60 Companies and which was not acquired by ATCO Gas or its employees or sub-contractors under any obligation of confidentiality;

(b) information which, at the time of the receipt or acquisition thereof by ATCO Gas or its employees or sub-contractors from ATCO Gas was or thereafter became a part of the public domain through no act or failure on the part of ATCO Gas or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and

(c) information which is disclosed to ATCO Gas or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to North of 60 Companies with respect to such information.

14.2 ATCO Gas and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by North of 60 Companies in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in ATCO Gas' performance of the Services) or disclose to any third party

(except as required to be disclosed by operation of law) such Confidential Information, provided that ATCO Gas may disclose such Confidential Information to those of ATCO Gas' employees or sub-contractors to whom disclosure is required for ATCO Gas' performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which ATCO Gas has assumed in this Article 14, and ATCO Gas shall ensure that all employees and sub-contractors at all times comply with such obligations.

14.3 North of 60 Companies shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

14.4 The terms of this Article 14 shall apply, mutatis mutandis, to North of 60 Companies' treatment of Confidential Information of or relating to ATCO Gas.

15. INTELLECTUAL PROPERTY

15.1 For the purposes of this Contract, "Intellectual Property" means

(a) all inventions, whether or not patentable,

(b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,

(c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and

(d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

15.2 All Intellectual Property made or conceived by ATCO Gas, its employees or sub-contractors:

(a) in the course of providing the Services;

(b) during the Term and which relates in any manner to the business of North of 60 Companies;

(c) made with or which arises with the use of the materials, equipment or resources of North of 60 Companies; and

(d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of ATCO Gas.

15.3 ATCO Gas shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

16. ASSIGNMENT

16.1 With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

17. FORCE MAJEURE

17.1 For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.

17.2 Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.

17.3 In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and North of 60 Companies shall either:

(a) terminate this Contract, or

(b) authorize ATCO Gas to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

18. TERMINATION

18.1 In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.

18.2 In the event of termination pursuant to this Article 18, ATCO Gas shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit ATCO Gas to carry out its duties under this Contract. North of 60 Companies shall not be liable for damages or loss of anticipated profits on account of such termination.

19. REMEDIAL WORK

19.1 ATCO Gas shall after receipt of notice from North of 60 Companies, at North of 60 Companies' option and at no cost to North of 60 Companies, without prejudice to any other right that North of 60 Companies might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by ATCO Gas in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. North of 60 Companies reserves the right to complete such remedial work or have such remedial work completed by other parties but at ATCO Gas' expense, in the event ATCO Gas fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from North of 60 Companies.

20. WAIVER

20.1 Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

21. REPRESENTATIVES AND NOTICES

21.1 North of 60 Companies' representative, who has full authority to represent North of 60 Companies in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

ATCO Gas' representative, who has full authority to represent ATCO Gas in

administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

21.2 Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

North of 60 Companies: See Schedule "C"

ATCO Gas: See Schedule "D"

21.3 Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

22. ENTIRETY OF AGREEMENT

22.1 This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.

22.2 There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.

22.3 No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

23. SEVERABILITY

23.1 Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without

affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

24. SURVIVAL OF TERMS

24.1 The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

25. GOVERNING LAW

25.1 The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

25.2 The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

26. INTERPRETATION

26.1 Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

26.2 In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

26.3 Where reference is made in this Contract to "North of 60 Companies' affiliates", such reference shall be meant to include:

(a) an Affiliate, within the meaning of the *Business Corporations Act*, of North of 60 Companies; and

(b) a partnership, joint venture, or person is which North of 60 Companies has a controlling interest or that is otherwise subject to the control of North of 60 Companies.

27. DISPUTE RESOLUTION

27.1 The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of North of 60 Companies and ATCO Gas.

27.2 If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

27.3 In the event that:

(a) such dispute is not resolved pursuant to Section 27.2 above; or

(b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

28. GENERAL PROVISIONS

28.1 The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

28.2 All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

28.3 This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

28.4 Time is of the essence in the performance of every obligation of this Contract.

28.5 This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

IN WITNESS WHEREOF the Parties have duly executed this Contract with effect from the date and year first above written.

North of 60 Companies	**ATCO Gas**
Per: _____	Per: _____
Name: _____	Name: _____
Per: _____	Per: _____
Name: _____	Name: _____

NORTH OF 60 COMPANIES
(NORTHLAND UTILITIES (NWT) LIMITED,
NORTHLAND UTLITIES (YELLOWKNIFE) LIMITED,
THE YUKON ELECTRICAL COMPANY LIMITED)
and ATCO GAS

METER READING AND PROCESSING SERVICES
Services Agreement #134/#60

As Amended February 1, 2011

Schedule "A" to the Master Services Contract

METER READING AND PROCESSING SERVICES

dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended February 1, 2011

SCOPE OF SERVICES

ATCO Gas will provide meter reading processing services to North of 60 Companies (North of 60) through the ATCO Gas Premierplus4 system as follows:

1. Download/upload of meter reading routes to handheld units.
   - Identify download/upload processes unique to North of 60.
   - Set up daily meter reading assignments for applicable Meter Readers.

2. Processing of meter readings so that they post to appropriate customer accounts in the billing system.
   - Maintain meter reading processing requirements unique to North of 60.
   - Modify ATCO CIS interface to allow processing of North of 60 data.

3. Report production and distribution
   - Identify reporting requirements unique to North of 60.
   - Define North of 60 report distribution requirements.
   - Modify report processing in Premierplus4.

4. System maintenance and enhancements
   - Maintenance and enhancements related to PP4 software will be coordinated by the PP4 System Manager.

5. Inventory tracking and maintenance
   - Establish and maintain distribution and maintenance records of handheld units and accessories.

Schedule "B" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended February 1, 2011

TERMS AND CONDITIONS

1. Term of Contract

This amending agreement shall commence effective February 1, 2011 and will remain in effect in perpetuity with annual renewal. If amendments to the current agreement are required a new agreement will be negotiated 3 months prior to the new effective date of the contract. In the event that either party wishes to terminate the contract, written notice to the manager is required at least 12 months in advance of the termination date.

ATCO Gas shall provide to North of 60 written notice of changes to ATCO Gas' systems or operation of its systems as soon as is practical that could result in changes in the cost of the service.

2. Cost of Service Provided

Labour Charges

- Direct labour costs will be based on actual labour dollars, including overtime as defined Policy 80.04.
- Overtime will be based on actual labour hours and dollars at two times the regular rate of pay.

Equipment and Shipping Costs

- All equipment purchased and shipping of the same, incurred for North of 60 will be charged to North of 60 at the actual cost incurred.

Use of ATCO Gas' assets in the provision of service

- ATCO Gas will recover the operating, depreciation and capital costs of any assets used in the provision of this service.

Direct Supplies

- Direct supplies will be charged to North of 60 at the cost incurred by ATCO Gas.

Overhead Rate

- ATCO Gas will charge North of 60 an overhead rate on all labour costs including supervision, burden and non-direct labour charges at the rate stated in Policy 80.04.

Schedule "B" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended February 1, 2011

TERMS AND CONDITIONS

2. Cost of Service Provided

Operating costs are estimated based on forecast volumes of usage per Appendix A. These estimated costs may be adjusted, with appropriate notice, to reflect changes in actual functionality or volumes used. Effective February 1, 2011 these costs are estimated to be $36,885 Canadian plus GST per annum.

3. Additional Support

Requests for additional support including, but not limited to:

- software maintenance and upgrading of equipment, processes and software specific to North of 60,
- training of new North of 60 Company staff , and
- any costs associated with termination of agreement by North of 60 (such costs may include, but are not limited to I-Tek charges for removal of North of 60 from meter reading systems and alterations to CAD mainframe applications to remove records, processes and reports)

Additional support will be billed in accordance with Policy 80.04. Special requests and non-routine work will be billed independently of ongoing operating costs.

4. Billing

The Financial Services department of ATCO Gas will be responsible for the charging of costs associated with this agreement through the inter-company debit note process, and the provision of details supporting the charges. Settlement of these charges will be consistent with the normal settlement date for inter-company transactions.

ATCO Gas will provide services to North of 60 Companies and charge to the following accounts:

- ATCO Gas charges services to account:
  001.72122.561014.11742.000.00000
  001.72119.561014.11700.000.00000
- ATCO Gas charges labour to account:
  001.71230.540000.11742.000.00000
- ATCO Gas records recovery in account 001.00000.413117.11742.011.00000.

Schedule "C" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended February 1, 2011

REPRESENTATIVE FOR

NORTHLAND UTILITIES (NWT) LIMITED

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED

YUKON ELECTRICAL COMPANY LIMITED

Dwight Redden
General Manager
100-1100 1st Avenue
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-3965
Email: dwight.redden@atco.com

D E Redden
Signature

Jan 27, 2011
Date

Schedule "D" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended February 1, 2011

ATCO GAS' REPRESENTATIVE

Blain Smetaniuk
Manager, Edmonton South
5623 – 82 Avenue
PO Box 2426
Edmonton, AB T5J 2V6
Telephone: (780) 733-2553
Email: blain.smetaniuk@atcogas.com

Signature

Jan. 21, 2011
Date

NORTH OF 60 COMPANIES
(NORTHLAND UTILITIES (NWT) LIMITED, THE YUKON ELECTRICAL COMPANY LIMITED) and ATCO GAS

METER READING AND PROCESSING SERVICES
Services Agreement #134/#60

As Amended April 1, 2013

Schedule "A" to the Master Services Contract

METER READING AND PROCESSING SERVICES

dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended April 1, 2013

SCOPE OF SERVICES

ATCO Gas will provide meter reading processing services to North of 60 Companies (North of 60) through the ATCO Gas Premierplus4 (PP4) and the Field Collection system (FCS) as follows:

1. Download/upload of meter reading routes to handheld units.
   - Identify download/upload processes unique to North of 60.
   - Set up daily meter reading assignments for applicable Meter Readers.

2. Processing of meter readings so that they post to appropriate customer accounts in the billing system.
   - Maintain meter reading processing requirements unique to North of 60.
   - Modify ATCO CIS interface to allow processing of North of 60 data.

3. Report production and distribution
   - Identify reporting requirements unique to North of 60.
   - Define North of 60 report distribution requirements.
   - Modify report processing in Premierplus4 or FCS as requested.

4. System maintenance and enhancements
   - Maintenance and enhancements related to PP4 or FCS software will be coordinated by Meter Reading Systems.

5. Inventory tracking and maintenance
   - Establish and maintain distribution and maintenance records of handheld units and accessories.

6. Yukon Energy Corporation services are being provided through a Memorandum of Agreement between ATCO Electric and Yukon Energy.

Schedule "B" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended April 1, 2013

TERMS AND CONDITIONS

1. Term of Contract

This amending agreement shall commence effective April 1, 2013 and will remain in effect in perpetuity with annual renewal. If amendments to the current agreement are required a new agreement will be negotiated 3 months prior to the new effective date of the contract. In the event that either party wishes to terminate the contract, written notice to the manager is required at least 12 months in advance of the termination date.

ATCO Gas shall provide to North of 60 written notice of changes to ATCO Gas' systems or operation of its systems as soon as is practical that could result in changes in the cost of the service.

2. Cost of Service Provided

Labour Charges

- Direct labour costs will be based on actual labour dollars, including overtime as defined Policy 80.04.
- Overtime will be based on actual labour hours and dollars at two times the regular rate of pay.

Equipment and Shipping Costs

- All equipment purchased and shipping of the same, incurred for North of 60 will be charged to North of 60 at the actual cost incurred.

Use of ATCO Gas' assets in the provision of service

- ATCO Gas will recover the operating, depreciation and capital costs of any assets used in the provision of this service.

Direct Supplies

- Direct supplies will be charged to North of 60 at the cost incurred by ATCO Gas.

Overhead Rate

- ATCO Gas will charge North of 60 an overhead rate on all labour costs including supervision, burden and non-direct labour charges at the rate stated in Policy 80.04.

Schedule "B" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended April 1, 2013

TERMS AND CONDITIONS

2. Cost of Service Provided

Operating costs are estimated based on forecast volumes of usage per Appendix A. These estimated costs may be adjusted, with appropriate notice, to reflect changes in actual functionality or volumes used. Effective April 1, 2013 these costs are estimated to be $26,160 Canadian plus GST per annum.

3. Additional Support

Requests for additional support including, but not limited to:

- software maintenance and upgrading of equipment, processes and software specific to North of 60,
- training of new North of 60 Company staff , and
- any costs associated with termination of agreement by North of 60 (such costs may include, but are not limited to I-Tek charges for removal of North of 60 from meter reading systems and alterations to mainframe applications to remove records, processes and reports)

Additional support will be billed in accordance with Policy 80.04. Special requests and non-routine work will be billed independently of ongoing operating costs.

4. Billing

The Financial Services department of ATCO Gas will be responsible for the charging of costs associated with this agreement through the inter-company debit note process, and the provision of details supporting the charges. Settlement of these charges will be consistent with the normal settlement date for inter-company transactions.

ATCO Gas will provide services to North of 60 Companies and charge to the following accounts:

- ATCO Gas charges services to account:
  001.72122.561014.11742.000.00000
  001.72119.561014.11700.000.00000
- ATCO Gas charges labour to account:
  001.71230.540000.11742.000.00000
- ATCO Gas records recovery in account 001.00000.413117.11742.005.00000.

Schedule "C" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended April 1, 2013

REPRESENTATIVE FOR

NORTHLAND UTILITIES (NWT) LIMITED

YUKON ELECTRICAL COMPANY LIMITED

Dwight Redden
General Manager
100-1100 1st Avenue
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-3965
Email: dwight.redden@atco.com

Signature

March 23, 2013
Date

Schedule "D" to the Master Services Contract

METER READING AND PROCESSING SERVICES

Dated November 1, 2003 between

North of 60 Companies and ATCO Gas

as amended April 1, 2013

ATCO GAS' REPRESENTATIVE

Blain Smetaniuk
Director, Edmonton South
5623 – 82 Avenue
PO Box 2426
Edmonton, AB T5J 2V6
Telephone: (780) 733-2553
Email: blaine.smetaniuk@atcogas.com

Signature

Mar. 25, 2013
Date

NORTH OF 60 COMPANIES -

(NORTHLAND UTILITIES (NWT) LIMITED, NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED AND THE YUKON ELECTRICAL COMPANY LIMITED)

OFFICE SERVICES

As amended January 1, 2008

Schedule "A" to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

SCOPE OF SERVICES

This agreement addresses the provision of personnel and equipment services for ATCO Gas to provide services in the administration and coordination of Office Services activities as required by the North of 60 Companies. Functions and activities to include:

1. Reprographics Services

- High speed duplicating
- Graphic design and forms design
- Electronic file publishing
- Offset printing
- Bindery and finishing
- Forms distribution

Schedule "B" to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

TERMS AND CONDITIONS

1. Term of Contract

This agreement shall commence January 1, 2008, and remain in effect in perpetuity.

In the event that amendments are required, a new agreement will be renegotiated three months prior to the new effective date of the contract. If either party wishes to terminate the contract, written notice is required at least six months in advance of the termination date.

2. Cost of Service Provided

Reprographics Services

Operating Costs - Fixed

- ATCO Gas will charge the North of 60 Companies a fixed hourly rate. This rate includes supervision costs, direct labour costs, office rent and equipment leases. This rate has been determined consistent with the requirements contained in the ATCO Gas Affiliate Accounting Policy 80.04.

Operating Costs – Variable

- Supplies and materials will be charged to the North of 60 Companies at the cost incurred by ATCO Gas.

- Overtime will be based on actual labour hours and dollars at two times the regular rate of pay. Overhead will be applied to overtime costs, at the rate stated in Policy 80.04.

Reprographics requisitions evidence actual monthly charges.

Schedule "B" to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

TERMS AND CONDITIONS

3. Billing

The Financial Services department of ATCO Gas will be responsible for the charging of costs associated with this Contract through the intercompany debit note process, and the provision of details supporting the charges. Settlement of these charges will be consistent with the normal settlement date for intercompany transactions.

Schedule "C" to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

REPRESENTATIVE FOR

NORTHLAND UTILITIES (NWT) LIMITED

NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED

AND THE YUKON ELECTRICAL COMPANY LIMITED

Jerome Babyn
General Manager
100 – 1100 1st Avenue
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Fax: (867) 668-6692
Email: jerome.babyn@atco.com

Jerome Babyn
Signature

Dec. 12/07
Date

Schedule "D" to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

ATCO GAS' REPRESENTATIVES

Marnie O'Brien
Vice President, Corporate Services
10035 – 105 Street
Edmonton, AB T5J 2V6
Telephone: (780) 420-7706
Fax: (780) 420-5077
Email: marnie.o'brien@atcogas.com

Signature Date

Jon Kowalczyk
General Supervisor, Office Services
10035 – 105 Street
Edmonton, AB T5J 2V6
Telephone: (780) 420-7015
Fax: (780) 420-3786
Email: jon.kowalczyk@atcogas.com

Signature Date

APPENDIX to the Master Services Contract

OFFICE SERVICES

Dated January 1, 2007 between

North of 60 Companies and ATCO Gas

As amended January 1, 2008

The estimated cost of the services for 2008 amounts to the following:

Office Services Section	Total
Reprographics	
Northland Utilities (NWT) Limited	$2,000
Northland Utilities (Yellowknife) Limited	$5,000
The Yukon Electrical Company Limited	$7,000
Total	$14,000

ATCO I-Tek COPY

ATCO I-Tek

Statement of Work

Provision of Services for North of 60 Companies

Project Number *PD00962*

Provided to: North of 60 Companies
Provided by: ATCO I-Tek Business Services Ltd.

Last Modified: February 13, 2009
Prepared by: **Business Support Team**
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STATEMENT OF CONFIDENTIALITY

This document is the proprietary and confidential information and property of ATCO I-Tek Business Services Ltd. (the "Supplier") and is governed by the obligations of non-disclosure and non-use in the Master Services Agreement (the "MSA") between the Supplier and ATCO Electric (the "Client"). Without limiting the foregoing, by accepting possession of this document, you, and any third party agents, consultants or contractors engaged by you, agree to keep the contents of this document in strict confidence, and not use, duplicate, or disclose its ideas or contents for any purpose other than evaluating the ability of the Supplier to provide the services described herein, and for the purposes permitted under the Master Services Agreement, unless otherwise agreed to in writing by the Supplier.

Without limiting the foregoing, disclosure of any of this information to any third party would be disclosure of trade secrets of the Supplier or other parties (including scientific, technical, commercial or financial information) supplied in confidence and would (i) prejudice significantly the competitive position of the Supplier, (ii) interfere significantly with the contractual and other negotiations of the Supplier, and (iii) result in material harm to the Supplier.

Revision History

Version Number	Revised By	Revision Date	Summary of Changes
1.0	ATCO I-Tek	February 2, 2009	Created document

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1 Document Purpose

The purpose of this Statement of Work (SOW) is to describe the services, deliverables, fees and term of service for the work to be provided by ATCO I-Tek Business Services Ltd. ("ATCO I-Tek") to the North of 60 companies using ATCO-CIS. Services shall be provided to:

- Northland Utilities (NWT) Ltd.
- Northland Utilities (Yellowknife) Ltd.
- Yukon Electrical Company Limited

This SOW is for the provision of services to the North of 60 companies and is governed by the ATCO Electric Master Service Agreement (MSA).

2 Executive Summary

The Old CIS Billing System was a vendor product built over 30 years ago and was purchased in the late 1970s to provide customer care and billing functionality to all of the utilities in the ATCO Group of Companies. Over the years, the ATCO utility companies have significantly enhanced and customized the functionality of Old CIS due to changes in business requirements. The application has been supported in-house for over 25 years.

As business requirements change, the system architecture and underlying technologies can reach their limitation making enhancements to meet the business requirements no longer viable. This was the case with the utility business model changes imposed by the deregulation of electric and gas utilities in Alberta. Old CIS could not be enhanced to accommodate the complexity of the changes and resulted in ATCO Gas and ATCO Electric commissioning a new customer care and billing system; ATCO-CIS. The Old CIS Billing System is currently used by the North of 60 Companies only. The process of decommissioning Old CIS will begin at the end of 2008. As a result, the North of 60 Companies required alternatives to Old CIS.

The North of 60 Companies selected ATCO-CIS to replace Old CIS and other satellite systems.

ATCO I-Tek Business Services will provide the North of 60 Companies the services described herein as directly related to the Client's provision of electricity services, electric energy and meter data management.

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3 Assumptions

The following is a list of assumptions ATCO I-Tek made in developing this SOW:

- The Client provides all wires-related products, services and energy.
- The Client is the primary and direct contact for all communications with customers unless otherwise directed herein, e.g., when the Supplier sends credit notices directly to Customers.
- The Services described herein are based on Client policies and system parameters in effect at the time of signing. Changes to these policies and parameters will require a Statement of Work or Change of Service Request.

4 Work Location

The hours of operation for ATCO I-Tek are 8 a.m. to 5 p.m. Mountain Standard Time (MST), on Business Days. All offices are located in Edmonton Alberta. The Supplier does not operate or have billing cycles on the following Canadian holidays: New Years' Day, Alberta Family Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labor Day, Thanksgiving Day, Remembrance Day, Christmas Day, and Boxing Day.

5 Effective Date

In the event that the Client requests that the Supplier change the priority of current project work, the Client acknowledges that the Supplier may be required to adjust its resource allocation prior to the commencement of or while working on this project. In this instance, the Project Plan developed to support this Statement of Work may be impacted and the Client may incur additional costs to complete the project objectives, or may be required to alter the completion date of this project.

This project commenced on November 1, 2008.

6 Term

The Supplier will provide the services described above to the Client effective the Service Date of November 1, 2008 and shall provide the services for a term ending December 31, 2013.

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If either Party elects not to extend or are unable to reach definitive agreement on the terms and conditions of any extension of the Term of this Statement of Work on or prior to the fourth (4th) anniversary of the Service Date, then the Supplier will forthwith prepare a Statement of Work outlining a transition plan and related Fees and Pass Through Charges associated with the termination of the Statement of Work on the fifth (5th) anniversary of the Service Date.

7 Approach

7.1 Solution Approach

The services currently offered to the North of 60 Companies by ATCO I-Tek Business Services will be modified to incorporate the changes for billing out of ATCO-CIS.

ATCO I-Tek will manage Client specified parameters in ATCO-CIS, as defined under the development project, to support Customer billing in a manner consistent with the Client's policies and business practices.

ATCO I-Tek will modify the following services using ATCO-CIS for the North of 60 Companies:

- Account Management: The services the Supplier provides to the Client to assist with the Client's management of accounts.
- Revenue Management: The services the Supplier provides to manage charges and adjustments including calculations, quality assurance and how bills are prepared.
- Receivables Management: The services the Supplier provides related to payments, credit adjustments and credit related activities for accounts receivable.
- Financial Management: The services the Supplier provides for balances and controls, internal accounts, financial reporting.
- Consulting and Special Services: A description of other Services the Supplier can provide to the client via a Request for Service.
- Administration: How the Supplier and Client work together to deliver the services described herein.

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8 Scope Statement

8.1 In Scope

The scope of this project hereunder includes only the specific tasks and deliverables performed by ATCO I-Tek in delivering the services set forth in this Statement of Work.

8.2 Out of Scope

The full scope of this proposal is included in sections nine (9) of this document. For clarity, the following items are not in the scope of this Statement of Work:

- ATCO-CIS training for North of 60 Companies staff.

9 Services

Commencing on the Service Date and for the duration of the term of this Statement of Work, the Supplier agrees to provide to the Client, and the Client agrees to obtain from the Supplier, the following Services for the North of 60 companies that are governed by the ATCO Electric Master Service Agreement (MSA).

Services shall be provided to:

- Northland Utilities (NWT) Ltd.
- Northland Utilities (Yellowknife) Ltd.
- Yukon Electrical Company Limited

9.1 Base Billing Services

ATCO I-Tek provides the following Base Billing Services to the North of 60 Companies.

- ATCO-CIS processing of each service account
- Manage Meter Reads
- Create and input Variable Parameter File (VPF)
- Converting reads to usage
- Managing usage
- Managing charges
- Quality assurance

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- Service charges
- Federal, Provincial and Local Taxes and Surcharges
- Contract Consolidated Billing
    - Paper only
- Payments
- Refunds
- Bill production
    - Distribution
    - Envelopes
    - Inventory Management
    - Inserting
    - Special Handling
- Bill messaging and inserts
- Charge and Statement check
- Balancing and controls
- Balancing ATCO-CIS Accounts
- Financial reporting
- Standard, System Generated Reports
- ATCO-CIS break/fix maintenance

9.2 Incremental Billing Services

ATCO I-Tek provides the following Incremental Billing Services to the North of 60 Companies:

- Printing
- Inserts and Folds

9.3 Additional Services

ATCO I-Tek provides the following Additional Services to the North of 60 Companies:

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- Price Schedule Value Changes
    - Price Schedule Value changes or changes to existing Price Structures in ATCO-CIS are managed through the Rate Administration process.
- Price Structure Changes and New Price Schedules
    - New or changed schedules require a Statement of Work. The Supplier will work with the Client to determine how best to implement schedules within existing system functionality.

10 Fee Schedule

The Client agrees to pay the actual Fees charged by the Supplier for the Services, pursuant to this Statement of Work.

10.1 One Time Fees

There is no one time fees associated to this Statement of Work.

10.2 Hourly Rates

Applies to services outlined where an hourly rate is denoted or when the number of hours exceeds any specified maximum.

10.3 Time and Materials Rates

Labour is charged on an hourly basis for the following types of Services:

(a) Statements of Work and Change of Service Requests,
(b) Development or modification and delivery of training required when changes to the Client's business practices or service offerings and staff necessitate,
(c) For other services required and not elsewhere defined.

10.4 Pass Through Charges

The Supplier, on behalf of the Client, can contract for Services as authorized by the Client and pass the charges onto the Client.

10.5 On-Going Fees

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On Going Fees	
Base Billing Services	
Monthly Base Fee (Metered)	$1.72/ Service Account
Monthly Base Fee (Non-Metered)	$1.02/ Service Account
Initial count of 876 Service Accounts	
Incremental Billing Services	
Printing	$0.12/ Page
Inserts and Folds	$0.03/ Insert or Fold
Additional Services	
Price Schedule Value Changes	$1973.50/ Request
Price Structure Changes and New Price Schedules	Management Services Rates
Fax or E-mail	$0.21/ Fax or E-Mail
Time and Materials Rates	
Professional Services Rates	
Senior Billing Specialist	$109.00/ Hour
Billing/ Training Rate	$70.00/ Hour
Management Services Rates	
Administrator	$62.76/ Hour
Analyst 1	$85.53/ Hour
Analyst 2	$105.50/ Hour
Analyst 3	$130.08/ Hour
Analyst 4	$143.93/ Hour
Consultants	$187.70/ Hour
Project Manager	$193.78/ Hour
Senior Consultant	$250.15/ Hour
Senior Project Manager	$277.94/ Hour
Pass Through Charges	Pass Through

The fees for Base Billing Services, Incremental Billing Services and Additional Services will be charged as indicated above for the duration of this agreement.

Time and Materials rates will be adjusted annually commencing January 1, 2009 by applying an annual adjustment for labour based on the Wynford Group Survey for Alberta.

Monthly Base Fee (Non-Metered) count will be increased annually by 1.5% commencing January 1, 2010 for the duration of the contract.

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11 Invoicing

The Supplier shall invoice the Client monthly. All invoices submitted under this Agreement shall contain a description of the period to which such invoice relates, an itemized statement of the Services performed and the unit price of each Service. Invoices shall be prepared and sent by the Supplier to the Client in each month following the month in which the Services are provided or the Fees, Pass Through Charges and Additional Expenses are incurred.

The Client shall pay, without set-off or deduction, all invoices within thirty (30) calendar days from the date of receipt of the relevant invoice. If the Client disputes the amount of any invoice, or any part thereof, the Client shall pay the invoice in full, including such disputed amounts. In the event it is determined that the disputed amount or any part thereof is not payable by the Client hereunder, the Supplier shall reimburse the Client.

12 Supplier Contacts

The Client and Supplier will designate representatives to deal with matters related to the provision of services described herein. The Client can contact the Supplier by fax, regular mail, internal ATCO mail, courier or email (using public folders).

- The communication channels are further described in the client communication model.

13 Change Management

Requests for changes or additions to the scope and particulars identified in this document must be received in writing on the Project Change Request Form using ATCO I-Tek's Project Change Control process. ATCO I-Tek will estimate each Change Request and the ATCO I-Tek Project Manager will determine cost and schedule impacts. If necessary, the Change Requests will be escalated to the Steering Committee/Project Sponsor(s) for final approval or rejection. Consideration of requests for any changes or additions shall not imply acceptance of such requests.

In response to the Change Request, ATCO I-Tek will provide an impact assessment of the following areas:

- The perceived value of the request within the context of the entire project
- The business implications of the requested change
- The effect of the change on project quality and project objectives
- The effect of the change on project schedule
- An assessment of the complexity level and risk associated with the request

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- The estimated expense of the request and the impact of the additional costs on the originally approved project budget

If the Change Request receives approval to proceed by the designated client representative(s), implementation of the approved change will be facilitated through a Project Change Addendum. This Addendum supplements the approved Statement of Work and Project Plan. Once the Project Change Addendum is approved, the ATCO I-Tek Project Manager will adjust the project schedule and/or other related project documents as required and work will proceed.

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14 Authorization

Our signatures below signify that we have the authority to commit to the terms of this document on behalf our respective companies. We have reviewed this document, and have found it to be a complete and true representation of our business and project requirements. We understand that if our requirements change or if we have additional requirements, the changes and additions will be evaluated and must be approved in writing.

APPROVER	DATE
	June 11/09

ATCO Electric

APPROVER	DATE
	February 13, 2009

Mike Jones
Director, Customer Care and Billing
ATCO I-Tek Business Services Ltd.

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CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

BETWEEN

ATCO I-TEK BUSINESS SERVICES LTD. ("SUPPLIER")

AND

ATCO ELECTRIC LTD. ("CLIENT")

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MASTER SERVICES AGREEMENT

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MASTER SERVICES AGREEMENT

This **MASTER SERVICES AGREEMENT** is made as of, and effective as of the 1st day of January, 2010.

BETWEEN:

ATCO I-TEK BUSINESS SERVICES LTD.
("**Supplier**")

- and -

ATCO ELECTRIC LTD.
("**Client**")

WHEREAS:

A. The Supplier has provided customer care and billing services for the Client's electric distribution business pursuant to that certain Master Services Agreement dated June 1, 2004 (the "**MSA**"), as amended by a letter agreement dated April 29, 2005, a letter agreement dated November 2, 2005, a letter agreement dated May 30, 2008 and an Amending Agreement dated effective March 1, 2008;

B. Effective as of the Effective Date, the Client requires customer care and billing services for its ongoing electric distribution business;

C. From and after the Effective Date, this Agreement replaces and supersedes the MSA which is hereby terminated and of no further force or effect; and

D. The Parties wish to set out the terms and conditions pursuant to which the Supplier will provide certain customer care and billing services to the Client during the Term of this Agreement.

NOW THEREFORE IN CONSIDERATION of the mutual covenants contained in this Agreement and other good and valuable consideration, the receipt and sufficiency of which are hereby irrevocably acknowledged, the Client and the Supplier agree with each other as follows:

ARTICLE 1
INTERPRETATION AND DEFINITIONS

1.1 Interpretation

(a) Wherever in this Agreement the context so requires, the singular number shall include the plural number and vice versa and any gender shall be deemed to include the feminine, masculine or neuter genders and person means an individual, partnership, corporation, trust (including a business trust), unincorporated association, joint venture or other entity, or a government or any

agency, department or instrumentality thereof and vice versa. Where a term is defined in this Agreement, a derivative of that term shall have a corresponding meaning unless the context otherwise requires.

(b) The term "**including**" shall be read as "**including but not limited to**" Other expressions derived from the word "**include**" are for illustrative purposes and are not meant to be limiting.

(c) The insertion of headings herein and the division of this Agreement into articles and sections are for convenience and reference only and shall not affect the interpretation hereof. The words "**hereof**", "**hereunder**" and similar expressions refer to this Agreement and not any particular section hereof; "**article**", "**section**", and "**subsection**" mean and refer to the specified article, section or subsection of this Agreement.

(d) Reference to any agreement, indenture or other instrument in writing means such agreement, indenture or other instrument in writing as amended, modified, replaced or supplemented from time to time, unless otherwise agreed to herein.

(e) Reference to any statute or regulation or bylaw shall be deemed to be a reference to such statute or regulation or bylaw as amended, re-enacted or replaced from time to time, unless otherwise agreed to herein.

(f) Time periods within which a payment is to be made or any other action is to be taken hereunder shall be calculated excluding the day on which the period commences, but including the day on which the period ends; and

(g) Whenever any payment to be made or action to be taken hereunder is required to be made or taken on a day other than a Business Day, such payment shall be made or action taken on the next following Business Day.

1.2 Definitions

Whenever used in this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following capitalized words and terms shall have the respective meanings ascribed to them as follows:

"**Access**" means "read only" or "read and write" access to computer files, as specified in Schedule A (Definition of Services) and/or any Change Request;

"**Additional Expenses**" has the meaning described in Section 8.7 (Additional Expenses);

"**Affiliate**" has the meaning given in the *Business Corporations Act* (Alberta);

"**Agreement**" means this agreement, including all Schedules attached hereto, and all Change Requests and Statements of Work prepared and executed pursuant to this agreement, as well as amendments, additions or modifications thereto;

"**Aggregate Volume**" means the aggregate volume of Services being delivered to and/or used by all of the ATCO Utilities;

"**Annual Review**" has the meaning described in subsection 7.10(a);

"**Applicable Law**" means the following as it is applicable to the performance of this Agreement:

(a) statute or proclamation or any delegated or subordinate legislation including Laws in any jurisdiction and which shall include Data Protection Legislation;

(b) Authority Requirements; and

(c) judgment of a court of law, board, arbitrator or administrative agency of competent jurisdiction.

"**Applicant**" has the meaning described in Section (1) of Schedule F (Arbitration);

"**Associate**" has the meaning given in the *Business Corporations Act* (Alberta);

"**ATCO Campus**" means the ATCO Centre, the Milner Building and the Standard Life Building in Edmonton, Alberta;

"**ATCO-CIS**" means the customer information and billing System that is owned by the Client and ATCO Gas, and will be used by the Supplier (under license) throughout the Term of this Agreement to provide the Services to the Client, as such System may be modified or enhanced by the Supplier or the Client from time to time;

"**ATCO-CIS Core Application Maintenance Fee**" means the fees described as such in Schedule C (Fee Schedule), which relates to the labour and test environment required to fix the Core Application (as defined in Schedule C (Fee Schedule)) when it fails to operate as per design specifications;

"**ATCO Gas**" means ATCO Gas, an operating name and division of ATCO Gas and Pipelines Ltd.;

"**ATCO Utilities**" means ATCO Electric and ATCO Gas and their respective Subsidiaries;

"**Authority Requirements**" means any ruling, determination, order, direction, directive, request for information, policy, administrative position or interpretation, guideline or rule of (or by) any Governmental Authority of competent jurisdiction concerning this Agreement;

"**Award**" means a decision by the Panel pursuant to Article 14 (Dispute Resolution);

"**Benchmarker**" has the meaning described in Section 8.4 (Price Reviews);

"**Benchmarking**" has the meaning described in Section 8.4 (Price Reviews);

"**Business Day**" means each of Monday, Tuesday, Wednesday, Thursday and Friday, except when the day occurs on a statutory holiday observed in the Province of Alberta;

"**Business Hours**" means the hours of 8:00 a.m. to 5:00 p.m., Mountain Time, during any Business Day;

"**CAC**" means Customer Assistance Centre;

"**Chairperson**" has the meaning described in Section (3) of Schedule F (Arbitration);

"**Change**" means any change, modification or enhancement to the provision of the Services which requires an amendment to this Agreement;

"**Change in Law**" means the issuance, creation, adoption, enactment, promulgation, modification, amendment, or revocation after the execution of this Agreement of any Applicable Law concerning this Agreement, including the performance of the Services, and including by way of example only those which may be related to, or affect the following:

(a) the gas sector, including any re-regulation or deregulation affecting supply, sale, distribution or transmission of natural gas, including customer choice of service provider;

(b) the electricity sector, including re-regulation or deregulation affecting generation, supply, sale, distribution or transmission of electricity, including customer choice of service provider; or

(c) the information technology service or customer care and billing services businesses.

"**Change of Control**" means to enter into any consolidation or merger, or enter into any transaction whereby more than fifty (50%) percent of the voting shares of a Party, all or substantially all of its undertaking or all or substantially all of its property and assets would become the property of any other person, whether by way of reconstruction, reorganization, recapitalization, consolidation, amalgamation, merger, transfer, sale, settlement or otherwise;

"**Change of Service Request**" or "**COS**" has the meaning described in subsection 4.1(a);

"**Change Response**" has the meaning given in subsection 4.1(d)(i).

"**Change Request**" has the meaning described in subsection 4.1(c);

"**Change Request Manager**" has the meaning described in subsection 4.2(a)(i)(B);

"**Chief Executive**" has the meaning described in subsection 14.1(b);

"**Claim**" means any and all claims, actions, damages, liabilities, losses, penalties, causes of action, suits, proceedings, demands, costs and expenses whatsoever, including reasonable legal fees and expenses on a solicitor and his own client basis;

"**Claiming Party**" has the meaning described in Section 9.10 (Procedure-Indemnities);

"**Client Data**" means the data provided to the Supplier by the Client or by a Retailer, Site Customer, Site Contact, Site Owner or other person for or on behalf of the Client, or obtained by the Supplier as directed by the Client, and data derived from such data;

"**Client Know-How**" has the meaning described in Section 11.7 (Client Know-How);

"**Client Manager**" has the meaning described in Section 7.6 (Client Manager);

"**Client Project Manager**" has the meaning described in subsection 7.8(b);

"**Client's Systems**" means any Systems owned by the Client or licensed to the Client by Third Parties or otherwise provided to the Client under contract by Third Parties and utilized in connection with the Services, including to provide Client Data to the Supplier, and including the Systems described in Schedule D (Client's Systems);

"**Commission**" means the Alberta Utilities Commission (AUC), and any replacement body therefor;

"**Computer Viruses**" means any codes, routines, programs, utilities or other devices that may have a detrimental effect on a System, or any part thereof, including those commonly referred to as computer viruses, computer worms or computer Trojan horses;

"**Confidential Information**" has the meaning described in Section 12.1 (Meaning of Confidential Information);

"**Core Services**" means those Services described in Schedule A (Definition of Services), other than those indicated or described therein as "Optional" or "Optional Services");

"**Critical Performance Indicators**" or "**CPIs**" means those Service Levels set forth in Schedule B (Service Levels), identified as CPIs therein;

"**Data Protection Legislation**" means the applicable international and Canadian federal or provincial legislation dealing with privacy, specifically, as at the Effective Date, the *Personal Information Protection and Electronic Documents Act*, S.C. 2000, c. 5; *Personal Information Protection Act*, S.A. 2003, c. P-6.5; (collectively the "**Privacy Acts**");

"**Default Supplier**" means the Retailer assigned to provide energy at Sites that were not Enrolled with a Retailer when required to do in accordance with Applicable Law;

"**Defaulting Party**" has the meaning described in Section 13.3 (Material Breach);

"**Deliverable**" means a deliverable which arises from the Services and which the Supplier has agreed in writing to deliver to or for the Client hereunder;

"**Directions**" has the meaning described in subsection 6.1(a);

"**Disclosing Party**" has the meaning described in Section 12.1 (Meaning of Confidential Information);

"**Discretion**" means sole, absolute, unfettered discretion and, in each case where such term is used in conjunction with the provision of consent or permission, also means that the person whose consent or permission is required may unreasonably and arbitrarily withhold such consent or permission, as the case may be;

"**Dispute**" means any dispute, controversy or Claim arising out of or in connection with this Agreement, or the breach, termination, validity or enforceability of any provision of this Agreement;

"**Distributor Site Customer**" means the end use customer at a Site whom the Distributor bills directly instead of through a Retailer;

"**Documentation**" means any documentation, manuals or other guides provided by the Supplier to the Client in connection with the Services, including hard copy and on-line user and technical documentation related to the use of Software;

"**Effective Date**" means the effective date of this Agreement, being January 1, 2010;

"**Executive Committee**" has the meaning described in Section 7.2 (Executive Committee);

"**Fee**" and "**Fees**" have the meaning described in Section 8.1 (Charges and Payments);

"**Governmental Authority**" means a court, ministry, minister, official, government department, government authority, government agency, commission, regulatory authority, regulatory agency, administrative tribunal, body that administers Laws, or body having competent authority concerning this Agreement;

"**General Performance Indicators**" or "**GPIs**" means those Service Levels set forth in Schedule B (Service Levels), identified as GPIs therein;

"**Indemnified Claim**" has the meaning described in subsection 9.10(a);

"**Indemnified Persons**" means, with respect to a Party, its Representatives, shareholders, directors, officers, consultants, suppliers, Affiliates and Associates;

"**Indemnifying Party**" has the meaning described in Section 9.10 (Procedures-Indemnities);

"**Indemnitee**" has the meaning described in subsection 9.9(a);

"**Indemnitor**" has the meaning described in subsection 9.9(a);

"**Interest**" means interest calculated at a compounded rate equal to two percent (2%) per annum above the prime rate established from time to time by the main branch in Edmonton of the Bank of Montreal, calculated and payable monthly;

"**Interface**" means the point at which the Client Data is delivered from the Client's Systems, a Retailer's Systems, a Site Customer's Systems or the Systems of another person, to the Supplier's Systems or ATCO-CIS, as the case may be;

"**Interim Administrator**" has the meaning described in subsection 9.7(a);

"**Interim Administrator Notice**" has the meaning described in subsection 9.7(a);

"**Interim Period**" has the meaning described in subsection 9.7(a);

"**Interim Reviews**" has the meaning described in subsection 7.10(a);

"**IP Claim**" has the meaning described in subsection 9.9(b);

"**IP Indemnitee**" has the meaning described in subsection 9.9(b);

"**IP Indemnitor**" has the meaning described in subsection 9.9(b);

"**IP Rights**" means all intellectual property, industrial property and other proprietary rights, whether conferred by statute, common law, contract, equity or otherwise, including copyright, patent, integrated circuit topography, trade secret, trade-mark rights and comparable rights, and rights of ownership of applicable applications and registrations;

"**Key Performance Indicators**" or "**KPIs**" means those Service Levels set forth in Schedule B (Service Levels), identified as KPIs therein;

"**Laws**" means all federal, provincial, state, local and municipal statutes, laws, by-laws, rules, codes, ordinances, orders (including court orders), directions and regulations in effect from time to time and made or issued by a Governmental Authority;

"**Legacy Pricing**" has the meaning described in subsection 3.2(b);

"**Legacy Systems**" has the meaning described in subsection 3.2(b);

"**Liability Cap**" means that amount equal to the total Fees paid by the Client to the Supplier hereunder (excluding Pass Through Charges and taxes) for the Services performed during the three (3) month period immediately preceding the event giving rise to the first Claim, regardless of the number of Claims, then or thereafter advanced by the Client;

"**Management Committee**" has the meaning described in Section 7.3 (Management Committee);

"**Material Breach**" has the meaning described in Section 13.3 (Material Breach);

"**Modifications**" has the meaning described in Section 3.1 (Modifications);

"**Non-defaulting Party**" has the meaning described in Section 13.3 (Material Breach);

"**Panel**" has the meaning described in Section 14.2 (Arbitration);

"**Parameter**" means a variable value in the billing system, which aligns with the Client's business requirements;

"**Party**" or "**Parties**" means a party or both parties to this Agreement, as applicable;

"**Pass Through Charges**" has the meaning described in Section 8.2 (Pass Through Charges);

"**Personal Information**" has the meaning set out in all applicable Canadian federal or provincial legislation dealing with privacy, including, as at the Effective Date, the Privacy Acts and includes all Personal Information, as that term is defined therein regarding identifiable individuals, who are customers of the Client and all employees of the Supplier and the Client;

"**Price Review**" means a review of the Fees and all other charges and amounts (except Pass Through Charges) payable by the Client to the Supplier hereunder;

"**Privacy Acts**" has the meaning given in the definition of "**Data Protection Legislation**";

"**REA**" means rural electrification association;

"**Recipient**" has the meaning described in Section 12.1 (Meaning of Confidential Information);

"**Recordings**" means telephone inquiries recorded on electronic media;

"**Records**" has the meaning described in Section 10.1 (Maintenance of Records);

"**Representatives**" means officers, employees, agents, contractors or subcontractors of a Party;

"**Request for Service**" and "**RFS**" has the meaning described in subsection 4.1(c);

"**Respondent**" has the meaning described in Section (1) of Schedule F (Arbitration);

"**Retailer**" a person providing electricity services directly to Retailer Site Customers, including competitive Retailers, Self-Retailers, Self Operating REAs, a person appointed by the Client as the regulated rate provider and the Default Supplier;

"**Retailer Site Customer**" means the end use customer at a Site when the Site is enrolled with a Retailer;

"**Review Period**" has the meaning given in subsection 4.2(c)(i);

"**Schedule**" means each schedule that is attached to and forms part of this Agreement;

"**Self-Operating REA**" means a REA that has made arrangements for the direct purchase of energy without using a Retailer;

"**Self-Retailer**" means a person who has made arrangements for the direct purchase of energy without using a competitive Retailer or the Default Supply Provider;

"**Service Credit**" means the amounts determined by the Parties for not achieving a minimum CPI as set forth in Section 2.8 (Service Credits);

"**Service Delivery Committees**" has the meaning described in Section 7.4 (Service Delivery Committees);

"**Service Level**" means the levels of performance to be achieved for certain Services as set out in Schedule B (Service Levels);

"**Service Policies**" means the policies of the Client applicable to the Services as more particularly described on Schedule A (Definition of Services), which may be amended, supplemented, superseded or replaced from time to time pursuant Article 4 (Changes in Service and Projects) hereto;

"**Services**" means the services to be provided by the Supplier to the Client as set forth in Schedule A (Definition of Services) and such other services as the Parties may agree to from time to time pursuant to Article 4 (Changes in Services and Projects) or any Change Request, including all Deliverables;

"**Site**" means a unique end use delivery point to which the Client delivers energy;

"**Site Contacts**" means the person or company designated as a contact for facility-related matters at a Site;

"**Site Customer**" means the person financially responsible for a Site;

"**Site Owner**" means the person named by the applicable Retailer as owning a Site, as provided in Update Customer Information transaction information;

"**Software**" means a computer software application in object code form and all configuration files and other material required to run the same and shall include all documentation relating thereto. Software shall also include all Source Code, data models, files and all other material required to modify and compile the Software when the rights relating to the Software include, by implication or otherwise, the right to modify the Software;

"**Source Code**" means computer programs written in higher-level programming languages including any accompanying programmer documentation;

"**Standards of Performance**" has the meaning described in Section 2.7 (Service Level Methodology and Performance Indicators);

"**Statement of Work**" and "**SOW**" has the meaning described in subsection 4.1(b);

"**Subsidiary**" has the meaning given in the *Business Corporations Act* (Alberta);

"**Supplier Know-How**" has the meaning described in Section 11.6 (Supplier Know-How);

"**Supplier Manager**" has the meaning described in Section 7.5 (Supplier Manager);

"**Supplier Project Manager**" has the meaning described in subsection 7.8(a);

"**Supplier's Systems**" means any Systems owned by the Supplier or licensed to the Supplier by Third Parties or otherwise provided to the Supplier under contract by Third Parties and utilized to provide Services to the Client, subject to Modifications by the Supplier from time to time;

"**System**" or "**Systems**" means hardware, middleware, firmware and Software, including interfaces, utilities, data, input and output formats, program listings, narrative descriptions and operating instructions, and all updates, enhancements, Modifications, or changes to the foregoing;

"**System Access Terms**" means the terms governing Access to Client Data or access to the Client's Systems, as the case may be, in the form attached as Schedule G (System Access Terms);

"**Target and Minimum Standards of Performance**" has the meaning described in Section 2.7 (Service Level Methodology and Performance Indicators);

"**Term**" has the meaning described in subsection 13.1(a);

"**Termination Transition Assistance Period**" has the meaning described in Section 13.6 (Transition Plan for Termination);

"**Termination Transition Plan**" has the meaning described in Section 13.6 (Transition Plan for Termination);

"**Termination Transition Services**" has the meaning described in Section 13.6 (Transition Plan for Termination);

"**Third Party (Parties)**" means a party or parties other than a Party or an Affiliate of a Party;

"**Time and Materials Rate**" at a particular time shall mean the Supplier's then current Time and Materials rate(s) as described in Schedule C (Fee Schedule), as may be amended from time to time by the Supplier;

"**Triggering Event**" has the meaning described in Section 13.4 (Triggering Events);

"**Work Location**" means the location from which work is performed or the Services are rendered;

"**Wynford Group Survey for Alberta**" means the salary survey for the Province of Alberta published by the Wynford Group; and

"**Year**" means each consecutive twelve (12) month period commencing from the Effective Date.

1.3 Fair Meaning

Any ambiguities concerning the terms and conditions of this Agreement shall not be resolved against the drafting Party. Any ambiguous or uncertain terms herein shall be given their fair and

reasonable meaning, taking into account, in part, the context of its use herein and the intentions of the Parties.

1.4 Meaning of Terms

All terms defined in the main body of this Agreement shall have the same meaning in all Schedules attached hereto, unless otherwise expressly defined therein.

1.5 Amendments and Priority of Contract Documents

Except as otherwise provided in this Agreement, this Agreement may not be amended, modified or superseded unless expressly agreed to in writing by both Parties. Without limiting the generality of the foregoing a Change Request will not have the effect of amending or overriding this Agreement unless the Change Request does so expressly and is agreed to in writing signed by both Parties. For the purposes of resolving any conflict within this Agreement, the order of priority of interpretation to resolve any conflict or contradiction of relevant terms and conditions in this Agreement shall, from highest to lowest in order of specificity over generality, be as follows:

(i) Highest – Schedules to this Agreement; and

(ii) Next Highest – main body of this Agreement.

1.6 Schedules

(a) This Agreement includes the following Schedules which are included in and form part of this Agreement:

(i) Schedule A - Definition of Services

(ii) Schedule B - Service Levels

(iii) Schedule C - Fee Schedule

(iv) Schedule D - Client's Systems

(v) Schedule E – Benchmarking Terms of Reference

(vi) Schedule F - Arbitration

(vii) Schedule G - System Access Terms

(viii) Schedule H - Termination Transition Plan

ARTICLE 2
SERVICES

2.1 Services

(a) Commencing on the Effective Date and for the duration of the Term of this Agreement, the Supplier agrees to provide to the Client, and the Client agrees to obtain from the Supplier, the Services, on the terms and conditions set forth herein. Notwithstanding the foregoing, or any other provision of this Agreement, if as of the Effective Date the Client has not provided to the Supplier all information reasonably necessary as well as its approval in respect of:

(i) all policies and Parameters related to the Services as contemplated in Schedule A (Definition of Services), including Directions required hereunder; and

(ii) all information identified or required pursuant to any Change Request setting forth implementation services to be provided by the Supplier to the Client to enable the Supplier to perform the Services hereunder;

then the Supplier will provide the Services to the Client, provided however that the Supplier's obligations in respect of the Service Levels shall absolutely not apply (including the Service Credits set forth in subsection 2.8(a) and the Supplier shall have no liability whatsoever therefor, or otherwise, directly or indirectly, in respect of the Services except as a result of its gross negligence or willful misconduct.

(b) Unless and until otherwise agreed by the Parties, the Supplier shall use ATCO-CIS to provide the Services to the Client hereunder.

(c) The Supplier and the Client shall cooperate to achieve reasonable economy, efficiency and effectiveness in the provision of the Services.

(d) Without limiting the foregoing, the Supplier shall use its commercially reasonable efforts to continually improve and innovate so as to increase the efficiency and quality of the Services in a manner, and to an extent, that is reasonably consistent with general industry practice during the Term.

2.2 Sufficiency of Resources

Without limiting the generality of Section 9.2 (Supplier Warranty) the Supplier shall have and maintain (and the Supplier does hereby represent and warrant that it has) the necessary Systems, experience, skill, resources, personnel, facilities and equipment to perform the Services in accordance with this Agreement, and such Systems, experience, skill, resources, personnel, facilities and equipment shall be qualified or adequate, as applicable, to perform the Services in accordance with the provisions of this Agreement.

2.3 Compliance with Applicable Law

(a) In providing the Services, the Supplier agrees to comply with Applicable Law, and to obtain and comply with any necessary regulatory approvals and permits applicable to the Supplier's business. The Parties shall consult and cooperate with one another regarding provision of the Services in compliance with Applicable Law, provided that the Supplier shall not be responsible for advising the Client on regulatory developments or compliance obligations of the Client, nor shall the Supplier be responsible for any failure or omission on the part of the Client in discharging its regulatory obligations.

(b) The Supplier will maintain all required licensing, registrations and permits in good standing, including the right to use the Supplier's Systems, for the provision of the Services as contemplated herein.

(c) In performing its obligations under this Agreement, the Supplier shall not be required to undertake any activity that would conflict with the requirements of Applicable Law, or obligations of confidentiality owed to any person, including to vendors or licensors.

2.4 Business Continuity Plan

Except as otherwise agreed between the Parties, the Supplier shall have in place a business continuity plan that meets accepted industry standards.

2.5 Insurance

The Supplier shall, at its own expense, obtain and maintain throughout the duration of this Agreement, and until all Services under this Agreement have been fully performed and completed, such insurance that a prudent supplier of customer care and billing services in similar circumstances would maintain based on factors including the availability of such insurance on commercially reasonable terms. Subject to the foregoing, the Supplier shall maintain insurance which at the Effective Date shall include:

(a) commercial general liability insurance, written on an "occurrence" basis, including products and completed operations liability, contractual liability and personal injury, with a combined single limit of not less than Two Million Dollars ($2,000,000) for each occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate involving bodily injury, death or property damage;

(b) crime and fidelity insurance in an amount not less than Two Million Dollars ($2,000,000) per occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate and covering all of the Supplier's Representatives for theft and fraud, including computer fraud, which results in loss to the Client;

(c) to the extent reasonably available, data processing errors and omissions coverage with a combined single limit of not less than Two Million Dollars ($2,000,000) per loss or claim and not less than two million ($2,000,000) dollars (plus associated defence costs) in the aggregate;

(d) errors and omission insurance with a combined single limit of not less than Two Million Dollars ($2,000,000) per loss or claim and not less than two million ($2,000,000) dollars (plus associated defence costs) in the aggregate, protecting the Supplier and its Representatives against their legal liability for loss or damages arising out of the rendering or failing to render the Services;

(e) property insurance for the full replacement value of any Supplier property located at the Client's premises in the Supplier's possession or control;

(f) property insurance for the full replacement value of any Client property in the Supplier's possession or control;

(g) employer's liability insurance covering each worker of the Supplier to the extent of not less than Two Million Dollars ($2,000,000) where such worker is not covered by Workers' Compensation or where Workers' Compensation coverage is not the worker's exclusive remedy; and

(h) automobile public liability insurance covering all vehicles used to provide the Services, whether owned, operated and/or leased by the Supplier or its Representatives, with a combined single limit of Two Million Dollars ($2,000,000) for each occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate of bodily injury, death or property damage.

The insurance required under this Section shall:

(i) name the Client as an additional insured;

(j) require the insurer to provide the Supplier with no fewer than thirty (30) calendar days written notice prior to cancelling or effecting a material change to the policies; and

(k) be maintained in effect during the Term and any renewal term, provided that any policies written on a "claims made" basis shall be maintained for at least one (1) year following the expiry or termination of this Agreement, howsoever caused.

2.6 Client's Payments

The Supplier shall deposit all payments, received by the Supplier on behalf of the Client, in a bank account of the Client with the Bank of Montreal in Edmonton, Alberta, in accordance with the procedures set out in Schedule A (Definition of Services) and shall not commingle (except funds paid in error to the Supplier) such payments with its own funds, the funds of any other client of the Supplier, or of any other person. The Client shall forward to the Supplier all

funds received by the Client in error that were due to the Supplier or one or more of the Supplier's other clients (including its Affiliates).

2.7 Service Level Methodology and Performance Indicators

Certain elements of the Services will be subject to particular standards of performance identified in this Agreement, and in particular Schedule B (Service Levels) that will include defined Target and Minimum Standards of Performance, designated as any one of the following performance indicators, Critical Performance Indicators ("**CPIs**"), Key Performance Indicators ("**KPIs**") and General Performance Indicators ("**GPIs**"). The Supplier will measure and report its performance against these Standards of Performance on a monthly basis, except as may otherwise be agreed between the Parties in respect of those particular Services. All Standards of Performance reporting will be at the Supplier's cost and are included in the Fee.

Performance Indicators

(a) Critical Performance Indicator (CPI)

CPI's have Target and Minimum Standards of Performance for Service Levels

(i) Consequences for failure to meet Target CPI:

If the Supplier fails to meet the Standard of Performance for certain Services designated as a target CPI for 4 times within a rolling 12 month period, the Supplier will pay the impacted Client a Service Credit. The failure is escalated to both the Executive Committee and Management Committee with root cause investigation and remediation plan.

(ii) Consequences for failure to meet minimum CPI:

If the Supplier fails to meet a minimum CPI in any month the Supplier will pay the Client a Service Credit and will not be able to earn the Service Credit back.

(iii) Consequences if performance is above the minimum CPI but below the target CPI:

If the Supplier incurs a Service Credit and then operates for a subsequent eight (8) consecutive months at or exceeding the target for the applicable CPI, the Supplier can earn the Service Credit back. Any additional failure to meet a target during this period will mean that such Service Credit cannot be earned back.

(iv) Consequences for failure to meet minimum CPI or target CPI:

The Supplier will conduct a root cause investigation to determine the cause of the failure and will present to the Client a remediation plan designed to prevent re-occurrence of such failure. Upon the Client's

approval the Supplier will implement such remediation plan at no additional cost to the Client.

(b) Key Performance Indicator (KPI)

KPI's have Target and Minimum Standards of Performance for Service Levels

(i) Consequences for failure to meet minimum KPI or target KPI:

If the Supplier fails to meet the Standard of Performance for certain Services designated as a target KPI for 4 times within a rolling 12 month period or the minimum KPI once within a 9 month rolling period the Supplier will conduct a root cause investigation to determine the cause of the failure and will present to the Client a remediation plan designed to prevent re-occurrence of such failure. Upon the Client's approval the Supplier will implement such remediation plan at no additional cost to the Client.

(c) General Performance Indicator (GPI)

GPI's do not have Target and Minimum Standards of Performance for Service Levels as GPIs measure the Client's operational elements and business objectives and not necessarily the Supplier's provision of the Services.

If the Supplier fails to meet a GPI, the Supplier will report such failure to the Client and will on the Client's request recommend measures to ensure that the failure does not occur again.

2.8 Service Credits

(a) If the Supplier fails to meet the Standard of Performance for a Service designated as a CPI and a Service Credit is required to be paid to the Client, the amount for each individual CPI missed will be 1.5% of the price of Core Services in that month. The maximum amount payable to the Client by the Supplier as a Service Credit in any month shall be capped at 10% of the Core Services for that month.

(b) The Supplier's failure to perform its contractual responsibilities, to perform the Services, or to meet Service levels or Standards of Performance shall be excused if and to the extent the Supplier's non-performance is caused by the Client's omission to act, delay, wrongful action, or failure to provide all and accurate information reasonably necessary to permit the Supplier to perform the Services.

ARTICLE 3
SYSTEM CHANGES

3.1 Modifications

Subject to Section 4.5 (Consent to Changes), the Supplier shall adopt and implement throughout the Term of this Agreement a progressive, commercially responsible policy for upgrading or otherwise modifying the Supplier's Systems or any part thereof ("**Modifications**") in order to perform the specified Services hereunder and the Client shall work co-operatively with the Supplier with respect to the implementation of the Modifications to enable the performance of the Services. Any Modification that requires the Client to pay for the Modification shall require an approved Change Request pursuant to Article 4 (Changes in Service and Projects).

3.2 Compatibility of Client's Systems

(a) Subject to Section 3.2(b), the Client shall, at its sole cost and expense, ensure that the Client's Systems remain compatible with the Supplier's Systems, including any Modifications thereto.

(b) If the Client advises the Supplier in writing that the Client may not wish to modify the Client's System to be compatible with Modifications to the Supplier's Systems, the Parties shall enter into a Change Request pursuant to Article 4 (Changes in Service and Projects) in respect of the Supplier's preparation of revised Fees to be charged by the Supplier for the Services ("**Legacy Pricing**"). Within thirty (30) days of the Parties entering into such Change Request, the Supplier shall provide the Client with the Legacy Pricing applicable if the Services continue to be provided by the Supplier using the Supplier's Systems without the Client modifying its Systems as referred to in Section 3.2(a) hereof ("**Legacy Systems**"). Within thirty (30) days of receiving the Supplier's Legacy Pricing, the Client shall advise the Supplier in writing whether the Client will modify the Client's Systems pursuant to Section 3.2(a), or continue to receive Services from the Legacy Systems subject to Legacy Pricing. In the event the Client elects to receive Services from the Legacy Systems, the Parties shall enter into a Change Request, as applicable, pursuant to Article 4 (Changes in Service and Projects).

ARTICLE 4
ADDITIONS AND CHANGES IN SERVICE AND PROJECTS

4.1 General

Any services requested by the Client which the Supplier is willing and able to provide that are in addition to the Services, unless otherwise agreed in writing between the Parties, shall be provided at the Supplier's then standard Time and Materials Rate unless otherwise specified in Schedule C (Fee Schedule). Upon agreement by the Supplier, such additional services shall be deemed to form part of the Services for all purposes of this Agreement. The Client shall request

such additional services using the procedures set out in this Article 4 (Changes in Service and Projects), including the following:

(a) the Client may seek to amend a Service Policy, or may seek a change, modification or enhancement to the provision of the Services (in each case, a "**Change of Service Request**" or "**COS**" which will result in the provision of the Services being changed, modified or enhanced;

(b) the Client may seek to amend a Service Policy and/or the Client may request that the Supplier undertake a specific project (in each case, a "**Statement of Work**" or "**SOW**", which upon its completion, will result in additional Services being performed by the Supplier;

(c) only the Client Manager, the Supplier Manager or their designated Representatives shall initiate any request for changes to the Services or for additional services by submitting to the other Party a written "**Request for Service**" or "**RFS**" describing the specific changes to the Services or additional services which are being requested and any other relevant information. The Supplier upon initiation or receipt of such written RFS, will within two (2) Business Days acknowledge receipt of the RFS and provide a reference number to the Client. Within ten (10) Business Days the Supplier will provide the Client with a response which will include the category for the COS or SOW as applicable (each of which may also be referred to as a "**Change Request**"), unless previously provided by the Client, the date when an estimate will be provided or additional information required or the need for a requirement gathering process; and

(d) in the event that the Client or the Supplier desires to make a Change to the Services or to the provisions of a Change Request, the following procedure will be followed:

(i) **Change Request** Subject to subsection 4.1(d)(ii) hereof, the Supplier, with the assistance of the Client, shall, as soon as reasonably practical after receipt of a request for a Change (or development of a proposal for a Change, in the case of a Change proposed by the Supplier), develop and deliver to the Client a response ("**Change Response**"):

(A) specifying how the proposed Change will be implemented;

(B) describing the effect, if any, that such Change will have on the Schedule for performance of the Services or Service Levels;

(C) specifying the applicable acceptance testing and acceptance procedures to implement the Change, if any;

(D) describing the changes to Fees, if any, that would result from the implementation of such Change;

(E) providing sufficient supporting documentation to justify any change in the Schedule for performance or in the cost of executing such Change; and

(F) within sixty (60) days of the end of each Year during the Term, unless otherwise agreed in writing by the Parties, the Supplier will prepare a consolidated list of previously approved Change Requests and any corresponding Fee adjustments that are subject to labour rate or labour component adjustment in accordance with the provisions of this Agreement.

(ii) **Additional Charges** Prior to preparing the Change Response, the Supplier will notify the Client of any costs which must be incurred to prepare the Change Response. In such event, the Client may:

(A) withdraw the request for the Change; or

(B) authorize the Supplier in writing to proceed to prepare the Change Response, in which event the Client will be liable to the Supplier for reasonable costs which it must incur to prepare the Change Response.

Upon receiving such authorization, the Supplier will use commercially reasonable efforts, in line with the size and scope of the request, to prepare the Change Response.

If the number of Change Responses that the Supplier is required to prepare in any month exceeds the Supplier's capacity to properly handle such work, the Supplier will give notice thereof to the Client. In such event, the Parties will meet promptly:

(1) to identify the requests for Change that may be deferred or withdrawn, and to prioritize the remaining requests for Change;

(2) to discuss what additional costs the Supplier is required to incur to permit it to prepare the Change Responses, and to determine whether the Client should compensate the Supplier for any of such additional costs; and

(3) to assess whether any other solution is available.

(iii) **Change Response** Promptly after the Supplier delivers a Change Response to the Client, both Parties will meet to determine whether to proceed with the Change in accordance with the Change Response. All approved Change Responses shall be deemed part of the Statement of Work, where applicable, and shall be implemented by the applicable Parties. If any approved Change Response requires an amendment of this

Agreement, such amendment must be made prior to the Change in question being effected and in accordance with Section 1.5 (Amendments and Priority of Contract Documents).

(iv) **Reasonable Requests** Each Party shall reasonably consider any Change proposed by the other, and shall, subject to the procedure set forth elsewhere in this Section, not acting in bad faith, use commercially reasonable efforts to negotiate a mutually agreeable agreement in respect of reasonable requests thereof.

4.2 Change Requests and Approval of Deliverables

(a) **Development of Change Requests**

(i) The Client shall initiate a request for a Change by submitting a RFS thereof to the Supplier. The RFS will describe the specific services that are required and any other relevant information needed to develop a Change Request in respect thereof. Upon receipt of the RFS, the Supplier, in consultation with, and with the reasonable assistance of, the Client, shall promptly prepare one or more draft Change Requests (it being acknowledged that the Supplier may divide the work into phases or parts with each phase or part having a separate Change Request), which shall, as applicable:

(A) describe the Services to be performed by the Supplier and any services to be performed and items to be provided by the Client;

(B) describe the roles and responsibilities of the Supplier and the Client, and whenever possible name the Representative of each Party who shall be its contact person for the development of the Change Request (in each case, the "**Change Request Manager**");

(C) specify the Work Location(s) where the Services will be performed;

(D) set forth the commencement date for the Services described in the Change Request and the period of time during which the Services will be provided there under;

(E) describe the Systems, equipment, scope and Deliverables to be provided during and at the completion of the Services;

(F) include a schedule showing the estimated time frame for all stages of the Services;

(G) specify the estimated costs of the Services and the schedule of payments to be made during and at the completion of the Services;

(H) describe the acceptance tests or means proposed for testing the Systems, equipment and Deliverables to be delivered during and at the completion of the Services; and

(I) specify such additional provisions as the Parties agree;

(ii) provided that the Supplier may, in its Discretion address a RFS without a Change Request, it being acknowledged that certain RFSs, typically of a minor or *de minimus* nature may be addressed in such fashion between the Parties.

(b) **Requirement for Formal Execution**

No agreement shall be formed in respect of a Change Request until execution by both Parties of such Change Request in accordance with the provisions of this Agreement. Either Party may, at any time and without liability, withdraw from any negotiations related to any RFS or draft Change Request.

(c) **Approval of Deliverables**

(i) To the extent that any Deliverable delivered to the Client by the Supplier requires the Client's approval under the terms of the relevant Change Request, the Client will have ten (10) Business Days (or such other period as the Parties' respective Change Request Managers may agree in writing or as may be specified in the Change Request) (the "**Review Period**") after delivery thereof within which to approve or reject such Deliverable. If the Client has a reasonable objection to any Deliverable, the Client may reject the Deliverable. In such event, the Client will deliver to the Supplier in writing within the Review Period the specific reasons for rejection and, where applicable, a single annotated copy of the Deliverable identifying required changes. The Supplier will make the appropriate corrections strictly in accordance with the Deliverable specifications in the Change Request. The Client shall again be entitled to the Review Period to approve or reject the revised Deliverable. If the Client does not expressly reject or approve a Deliverable or revised Deliverable, as the case may be, within the Review Period, the Deliverable in question shall be deemed approved.

(ii) Corrections to a Deliverable that is deficient because of the Supplier's omissions or errors or due to non-conformity with any applicable specifications provided to the Supplier as part of the applicable Change Request shall be made at the sole cost of the Supplier. The cost of corrections to a Deliverable occasioned by changes made to the Change Request by the Client or costs incurred as a result of delays caused by the Client (and provided such delays are not caused by or contributed to by the Supplier) shall be the responsibility of the Client. If the Client requires additional time to review any Deliverable provided to it under this Section

for approval, the Supplier will cooperate with the Client to extend the Review Period.

4.3 Project Management

The Client and the Supplier will utilize a common project management methodology that is consistent with commercially reasonable industry practices and standards. The Supplier will maintain the project management methodology that is used in the delivery of services. The Supplier will periodically update the project management methodology. The project management reporting and documentation will be agreed to by the Client and the Supplier. The Supplier will participate in appropriate project management programs.

4.4 Request due to Laws of Governmental Authority

(a) If a Change Request is required to be prepared in order for the Client or the Supplier or their respective Affiliates to comply with Applicable Law and such Change Request will require the Supplier to change the manner in which the Services are provided or to provide additional Services on an expedited basis, the Supplier shall use commercially reasonable efforts to meet such requirements on an interim basis in order to comply with such Applicable Law as soon as reasonably practicable and legally required, notwithstanding that the Change Request in respect of such requirement may not be finalized.

(b) The Client shall pay the Supplier monthly at the Time and Materials Rate for the Services provided on an interim basis hereunder. The Parties shall adjust all amounts paid pursuant to this Section in accordance with the Fees agreed to in the finalized Change Request.

(c) It is understood and agreed that the Parties will use commercially reasonable efforts to negotiate the Change Request while the interim Services are being provided. The terms of the Change Request shall be resolved in accordance with the provisions of Article 14 (Dispute Resolution) if the Parties cannot agree to a Change Request within ninety (90) days from the date such requirement is made known to the relevant Party.

4.5 Consent to Changes

Except as set forth in this Section or as otherwise expressly provided in this Agreement, the Supplier shall not, in any event, be limited or restricted from conducting its business in its Discretion, including adopting and implementing any such initiatives, subcontracting, delegation, the right and opportunity to enter into confidentiality agreements with respect to any aspect of its business or proposed business, fulfilling its obligations to Third Parties as they arise and complying with Applicable Law. Nothing in this Section relieves the Supplier of its responsibility to perform the Services, and:

(a) the Supplier shall obtain the Client's written consent prior to outsourcing, subcontracting or delegating of, or a material change to, the Supplier's management of customer relations or billing practices, provided that the Client's

consent shall not be unreasonably withheld, shall be given in a timely fashion, with no unreasonable conditions or delays, and provided further that the Supplier shall not require the Client's prior consent to such outsourcing, subcontracting or delegation to an Affiliate of the Supplier;

(b) the Supplier shall obtain the Client's written consent prior to relocation of the CAC premises as it exists at the Effective Date used directly to provide the Services (except to any other location within the ATCO Campus), provided that the Client's consent shall not be unreasonably withheld, shall be given in a timely fashion, with no unreasonable conditions or delays;

(c) the Supplier shall adopt and implement throughout the Term of this Agreement, a policy of notifying the Client Manager of a technology change to the Supplier's Systems used directly in the provision of the Services that could be reasonably foreseen as having a material adverse effect upon the Services.

The Supplier and the Client shall work co-operatively to facilitate the implementation of new initiatives, outsourcing, subcontracting, delegation or the transition to a new location for the CAC hereunder.

ARTICLE 5
PERSONNEL

5.1 Responsibility for Personnel

In connection with the performance of the Services, the Supplier:

(a) acknowledges that with respect to Representatives performing the Services who are employees of the Supplier, it is responsible for all aspects arising out of the employer-employee relationship between it and each such employee, including working conditions, the provision of supervision, responsibility for hiring, dismissal, discipline, direction and control, the payment of salary, the withholding and remittance of taxes, pension plan contributions, employment insurance, health care, workers' compensation, severance obligations and any other premiums and amounts payable by an employer in respect of an employee;

(b) shall be responsible for the acts or omissions of its Representatives performing the Services in accordance with this Agreement; and

(c) covenants that all Representatives involved in the provision of the Services will be trained and competent in performing the assigned work.

5.2 Compliance With Client and Supplier Policies

The Parties shall require all of their respective Representatives, when attending at the other Party's premises, including in the case of the Supplier, when performing Services at the Client's Work Location, to comply with the other Party's applicable policies and regulations of

which the attending Party is made aware, particularly in respect of security. The Client will be responsible to the Supplier for any additional Fees (at the Time and Materials Rate) attributable to the Supplier's compliance with applicable Client policies and regulations.

ARTICLE 6
CLIENT RESPONSIBILITIES

6.1 General

The Client shall provide such cooperation, information and assistance as described in the Agreement, including in any Schedule, Change Request, or as may be reasonably requested by the Supplier from time to time to enable the Supplier to provide the Services. The Client shall also be responsible for, on an ongoing basis during the Term and any renewal Term:

(a) providing instructions, direction and decisions on a timely basis as requested by the Supplier from time to time, including direction as to policies, Parameters and procedures to be applied in the delivery of the Services as contemplated in Schedule A (Definition of Services), or any executed Change Request (collectively, "**Directions**"). The Client shall be solely responsible and liable for all such Directions adopted or provided by the Client hereunder regardless whether the Supplier provided recommendations or other input to the Client in respect of such Directions; and

(b) making available for reference and use by the Supplier such data, documentation and other materials, Systems and information including the Client's Systems (including Site Customer enrollment information, changes in billing dates for the Client's distribution services and other information necessary for the Supplier's delivery of the Services);

which are specified in or contemplated to be provided by the Client under this Agreement, or otherwise as required to enable the Supplier to provide the Services to the Client.

6.2 Client Data

(a) The Client shall deliver or cause to be delivered to the Supplier at the Interface, all necessary Client Data in industry standard file formats, or as required by any Systems (including Modifications thereto) of which the Client is advised (or as otherwise mutually agreed in writing by the Parties).

(b) The Client shall be responsible for and shall take reasonable steps to ensure all Client Data provided to the Supplier from any source, including Retailers, Site Customers and other persons is accurate, legible, complete and current.

(c) The Client shall be responsible to the Supplier for reasonable Fees associated with any additional Services caused by the failure to provide accurate, legible and complete Client Data in the format or at the times agreed to in writing by the Parties or for any other errors or deficiencies whatsoever in Client Data provided

to the Supplier (including incorrect formatting, incorrect or faulty files or incorrect data mapping) which may impact the Agreement, including any Change Request, or any other Services agreed to in writing by both Parties.

6.3 Client Access to the Supplier's Systems

The Supplier shall permit the Client Access to Client Data on ATCO-CIS pursuant to a Change Request in accordance with Schedule A (Definition of Services) (including Section 7.4 thereof), and subject to the following:

(a) the Client shall and shall cause its Representatives to, comply with the Supplier's written security policies and updates and changes thereto as provided by the Supplier;

(b) the Client shall be responsible, at its sole cost and expense, for ensuring the security of the Supplier's Systems in connection with the Client's and its Representatives' Access to Client Data hereunder, including controlling the confidentiality and use of user identifications and passwords provided by the Supplier for the purpose of Accessing the Client Data. Without restricting the generality of the foregoing, the Client shall undertake all reasonable steps to prevent unauthorized access to and/or use of any portion of the Supplier's Systems, or unauthorized interference with, or unauthorized access, alteration, loss or destruction of any data or other content in whatever form or medium stored, cached or otherwise available on or through the Client's or its Representatives' access to Client Data hereunder;

(c) neither the Client, nor its Representatives shall (and the Client shall ensure that its Representatives do not) input, copy or manipulate any data, utilities, programs or other information to or from the Supplier's System (including the Client Data stored on such Systems) while obtaining Access to the Client Data;

(d) the Client shall be responsible for any Claims, including damages caused to any person's Systems, including the Supplier's Systems, resulting directly or indirectly from the Access provided to the Client and its Representatives pursuant to this Section 6.3, including interference with or unauthorized use of the Supplier's Systems by the Client or its Representatives, or any Third Party access to the Supplier's Systems;

(e) the Client shall, and shall cause each of its Representatives who will be granted Access to the Client Data to comply with the System Access Terms, which System Access Terms must stipulate whether such Access shall be on a "read only" or "read and write" basis, the purpose for which such Access may be exercised, and any restrictions on the Access granted thereunder.

6.4 Supplier Access to the Client's Systems

The Client shall permit the Supplier to use and access any Client's Systems which are required to provide the Services, subject to the following:

(a) the Client shall be responsible for obtaining at its own cost any necessary consents (whether required at the Effective Date or thereafter) required to:

(i) transfer any hardware, Software or other System to the Supplier;

(ii) permit the Supplier and its Representatives to use or access any hardware, Software or other System owned by or licensed to the Client, including the Client's Systems;

which is required in order to provide the Services. The Supplier shall be entitled, upon request, to review such consents and to retain copies of same;

(b) the Supplier shall and shall cause its Representatives to, comply with the Client's written security policies and updates and changes thereto as provided by the Client;

(c) the Supplier shall be responsible, at its sole cost and expense, for ensuring the security of the Client's Systems in connection with the Supplier's and its Representatives' access hereunder, including controlling the confidentiality and use of user identifications and passwords provided by the Client for such purpose. Without restricting the generality of the foregoing, the Supplier shall undertake all reasonable steps to prevent unauthorized access to and/or use of any portion of the Client's Systems, or unauthorized interference with, or unauthorized access, alteration, loss or destruction of any data or other content in whatever form or medium stored, cached or otherwise available on or through the Supplier's or its Representatives' access hereunder;

(d) neither the Supplier, nor its Representatives shall (and the Supplier shall ensure that its Representatives do not) input, copy or manipulate any data, utilities, programs or other information to or from the Client's Systems while exercising its rights of access to the Client's Systems hereunder;

(e) Subject to Article 9 (Warranties and Liabilities), the Supplier shall be responsible for any Claims, including damages caused to any person's Systems, including the Client's Systems, resulting directly or indirectly from the access provided to the Supplier and its Representatives pursuant to this Section 6.4, including interference with or unauthorized use of the Client's Systems by the Supplier or its Representatives, or any Third Party access to the Client's Systems;

(f) Subject to Article 9 (Warranties and Liabilities), the Supplier and each of its Representatives who will be granted access hereunder shall comply with the System Access Terms, which System Access Terms must stipulate whether such access shall be on a "read only" or "read and write" basis, the purpose for which such access may be exercised, and any restrictions on the access granted thereunder.

6.5 Compliance with Applicable Law

The Client agrees to comply with Applicable Law, to obtain and comply with any necessary approvals (and to independently examine Applicable Law), and to obtain any necessary approvals applicable to the Client's use of the Services.

6.6 Workload Planning

(a) The Supplier and the Client will annually review any volume forecasts and other workload planning information required to provide the Services as described in Schedule A (Definition of Services) and meet any Service Level as described in Schedule B (Service Levels). The Client will, on commercially reasonable basis, inform the Supplier of any external circumstances that may affect volume forecasts. Client directed events or change in regulation that would affect volume forecasts and workload planning will require the Client to submit a COS.

(b) The Client acknowledges and agrees that the Services provided to the Client as of the Effective Date are based upon the Service Policies in place at the Effective Date

(c) The Client and Supplier will meet annually for purposes of planning and determining Change Request work for the upcoming year.

ARTICLE 7
GOVERNANCE

7.1 General

This Article sets out the manner in which the Parties shall facilitate and conduct general contract performance relations, relationship management and related communications between them.

7.2 Executive Committee

There will be an "**Executive Committee**" that will be comprised of both Client and Supplier senior executives who will meet at least twice per calendar year or as deemed necessary.

7.3 Management Committee

There will be a "**Management Committee**" that will be comprised of the Supplier Manager, Client Manager and other managers as appointed by the Executive Committee. The Management Committee will meet quarterly or as deemed necessary.

7.4 Service Delivery Committees

Each service delivery committee (a "**Service Delivery Committee**") may be comprised of the Supplier Manager, Client Manager, service delivery manager, operational managers' and other representatives as appointed by the Management Committee. Each Service Delivery Committee will meet monthly or as deemed necessary.

7.5 Supplier Manager

The Supplier shall designate a Representative (the "**Supplier Manager**") of suitable skills and expertise who shall serve as the contact person at the Supplier for the Client in respect of all or a defined subset of Services. The name and contact information (including in case of an emergency) of the Supplier Manager shall be communicated to the Client in writing. The Supplier Manager shall be available for consultation during Business Hours and in case of an emergency and shall have appropriate authority to make operational decisions and commitments on the part of the Supplier. The Supplier Manager shall be responsible for liaising with the Client Manager and its Representatives appointed in accordance with Section 7.7 (Representatives of Managers), and for facilitating necessary cooperation, information and assistance as may be reasonably required to enable the Supplier to provide the Services.

7.6 Client Manager

The Client shall designate a Representative (the "**Client Manager**") of suitable skills and expertise who shall serve as the contact person at the Client for the Supplier in respect of all or a defined subset of Services. The name and contact information (including in case of an emergency) of the Client Manager shall be communicated to the Supplier in writing. The Client Manager shall be available for consultation during Business Hours and in case of an emergency and shall have appropriate authority to make operational decisions and commitments on the part of the Client. The Client Manager shall be responsible for liaising with the Supplier Manager and its Representatives appointed in accordance with Section 7.7 (Representatives of Managers) and for facilitating necessary cooperation, information and assistance as may be reasonably required to enable the Supplier to provide the Services.

7.7 Representatives of Managers

The Supplier Manager and the Client Manager may designate in writing one or more Representatives who will represent such Manager during his absence and in respect of designated areas.

7.8 Project Managers

(a) The Supplier will designate in writing its Representative with respect to each Change Request (the "**Supplier Project Manager**") who will be authorized to act generally as the primary point of contact for the Client in dealing with the Supplier and to coordinate the Supplier's provision of the Services pursuant to the particular Change Request. The Supplier Project Manager for any Change Request may be the same person as the Supplier Manager.

(b) The Client will designate in writing its Representative with respect to each Change Request (the "**Client Project Manager**") who will be authorized to act generally as the primary point of contact for the Supplier in dealing with the Client pursuant to a particular Change Request. The Client Project Manager shall be responsible for directing, insofar as the Supplier is concerned, all activities of the Client affecting the provision by the Supplier of the Services pursuant to such Change Request. The Client Project Manager for any Change Request may be the same person as the Client Manager.

7.9 Reliance

Each Party shall have the right to rely upon the instructions and decisions received from the other Party's Manager appointed under Sections 7.5 (Supplier Manager) or 7.6 (Client Manager) (or their respective designates pursuant to Section 7.7 (Representatives of Managers)) or Project Manager appointed under Section 7.8 (Project Managers), as the case may be, with respect to all matters relating to this Agreement pursuant to any Change Request, or otherwise as applicable under this Agreement. The Supplier and the Client shall forthwith notify the other Party of the replacement of its Manager or a Project Manager, including the contact information for such replacement.

7.10 Annual and Interim Reviews

(a) The Supplier and the Client shall be prepared to review this Agreement at the Supplier's location within twenty (20) Business Days of the end of each of the first three quarters of a Year (the "**Interim Reviews**") and within thirty (30) Business Days of the end of each Year (the "**Annual Review**") and such other times as may be mutually agreed in writing. Each review will address Service Levels, business transaction volume projections, mutually agreed additions, deletions or changes to Services (including those required to implement requests or recommendations for enhancing the efficiency or value of the Services hereunder), the status of Change Requests then underway, the Supplier's performance over the previous period, and the impact of changes in regulatory and Client business requirements. The Interim Reviews shall be conducted utilizing the best information reasonably available and may include interim, preliminary and estimated factors. The Annual Review shall be more complete and comprehensive and, to the fullest extent practicable, be based on actual final data.

(b) Within ten (10) Business Days of an Interim Review and ten (10) Business Days of an Annual Review, the Supplier shall prepare and submit to the Client a draft written report which accurately and completely describes the discussion and findings of the review. If the Client is of the view that changes to the draft report are required, the Parties shall meet to discuss such changes. If a dispute arises as to the content of the report, that cannot be resolved, the views of both Parties shall be included in the final report which the Supplier shall prepare and deliver to the Client within ten (10) Business Days of the Parties meeting to discuss the draft report.

ARTICLE 8
CHARGES AND PAYMENTS

8.1 Charges and Payments

In consideration of the provision of the Services (including Services provided pursuant to any Change Request), the Client shall pay to the Supplier the fees, charges, costs and expenses set forth in Schedule C (Fee Schedule) and set forth in any Change Request (individually a "**Fee**" and collectively "**Fees**") as adjusted pursuant to this Article 8 (Charges and Payments).

8.2 Pass Through Charges

The Supplier, on behalf of the Client, can contract for products and services in order to perform the Services as authorized by this Agreement or the Client, as the case may be, and pass the charges onto the Client. The Client shall reimburse the Supplier for all expenses it incurs in performing the Services and described as Pass Through Charges on any Schedule or Change Request ("**Pass Through Charges**"), including Section 6 of Schedule C (Fee Schedule). The Supplier will take reasonable care to reduce Pass Through Charges by applying "best value for money spent" principles, to the extent to do so is consistent with its other obligations hereunder.

8.3 Fees and Adjustment for Inflation

Subject to the other terms of this Agreement, during the Term:

(a) the Fees applicable to the Core Services shall be as set forth in Schedule C (Fee Schedule), and shall not be subject to any adjustment for inflation during the Term;

(b) the Fees payable for ATCO-CIS Core Application Maintenance Fee shall be a monthly fixed fee as set forth in Schedule C (Fee Schedule), and shall not be subject to any adjustment for inflation during the Term;

(c) any amounts payable pursuant to Change Requests where the Time and Materials Rates are applied, shall be adjusted as of the Effective Date by applying an annual percentage adjustment to labour rates or the labour component of the Test Environment Charge (as described on Schedule C (Fee Schedule)) based on the Wynford Group Survey for Alberta, provided that, if the Wynford Group Survey for Alberta should no longer be published or should be substantially changed in content or format after the Effective Date, the Supplier and the Client will substitute another comparable measure.

8.4 Price Reviews

Once during the Term and commencing no earlier than thirty (30) months after the Effective Date, the Client will request that a benchmarking study be performed by an independent Third Party (a "**Benchmarker**") with the characteristics noted in Schedule E (Benchmarking Terms of Reference) to compare the quality and price of all of the Services against the quality and price of other well-managed providers performing

similar services to provide assurance that the Client is receiving from the Supplier pricing and levels of service that are competitive with market rates, prices and service levels, given the nature, volume and type of services provided by the Supplier for a representative measurement period (typically one month) on an Aggregate Volume basis ("**Benchmarking**"). The Benchmarker may be hired and the Client may provide the Benchmarker with instructions and information prior to the thirtieth (30^{th}) month after the Effective Date. Any such Benchmarking may not commence earlier than thirty (30) months after the Effective Date. In making this comparison, the Benchmarker shall consider such factors as the Benchmarker typically considers in its benchmarking methodology, including but not limited to the following factors and adjust the prices as and to the extent as defined in the report or as a result of Benchmarking or otherwise as appropriate: (i) any financial engineering, such as whether provider transition charges are paid by the customer as incurred or amortized over the Term; (ii) the extent to which this Agreement calls for the Supplier to provide and comply with unique Client requirements; (iii) nature, size, scope and term of the contract, and (iv) service locations.

General. Any Benchmarker engaged to perform the Benchmarking shall execute a non-disclosure agreement with the Client and the Supplier and must be independent of both the Client and the Supplier (without any conflict of interest) and have recognized expertise with benchmarking expertise in the business process outsourcing industry for customer care and billing functions (including methodology and data source experience), and must not be either a provider of similar services, direct Client competitor or a direct Supplier competitor. Notwithstanding the foregoing, the Supplier hereby consents to the Client's use of any Benchmarker listed in Schedule E (Benchmarking Terms of Reference) for the purposes of the defined Benchmark. Other than a Schedule E (Benchmarking Terms of Reference) Benchmarker, the Benchmarker list (including any revisions thereto) shall be mutually agreed to in writing by the Client and the Supplier. The Benchmarker shall be engaged on terms consistent with this Section and Schedule E (Benchmarking Terms of Reference) and otherwise acceptable to the Client. The Supplier and the Client shall cooperate on a commercially reasonable basis with the Benchmarker and shall provide commercially reasonable access to any premises, personnel or documents and provide any commercially reasonable assistance required by the Benchmarker to conduct the Benchmarking, all at the Client's and the Supplier's respective commercially reasonable cost and expense assuming the Benchmarking is conducted in accordance with this Agreement. The Benchmarking shall be conducted so as not to unreasonably disrupt the Supplier's operations under this Agreement.

Result of Benchmarking. If the Benchmarker finds that the charges paid by the Client for all Services on an Aggregate Volume basis, in aggregate (having considered charges for all Services in aggregate and charges for each individual Service Category), are greater than the average of the prices charged by other well-managed providers for work of a similar nature, type and volume, the charges shall be adjusted to eliminate such variance at the aggregate level of all Services. On an Aggregate Volume basis, pricing may be rebalanced across all Services in order to eliminate such variance. Provided that the Benchmarking study is completed and delivered to the Parties no later than March 1st of the year following the commencement of the Benchmarking, such adjustments shall become effective January 1st of the year following the commencement of the

Benchmarking. In the event that the completion and delivery of the Benchmarking study is delayed and the delay is not principally attributed to the Supplier, then such adjustments shall become effective as of the first day of the next month following the month during which the Benchmarking study is completed and delivered to the Parties. The Supplier reserves the right to challenge the Benchmarker's report pursuant to the dispute resolution process described in Article 14 (Dispute Resolution). Any reversal of the Benchmarking findings will be effective retrospectively to the date any adjustments based on the reversed Benchmarking became effective. Regardless of the results and determination of the Benchmarking, whether as to the competitiveness of the Supplier's prices at any Service Level or otherwise, the Client shall not be required to accept or pay any increase in any fees or prices payable to the Supplier under this Agreement in response to a Benchmarking.

Supplier Review and Dispute. The Client shall provide the Supplier with a copy of the Benchmarker's report and Supplier shall have fourteen (14) Business Days to review such report and contest the Benchmarker's findings. If the Parties are unable to agree upon the validity of such findings, the matter shall be resolved pursuant to the dispute resolution process set forth in Article 14 (Dispute Resolution). Reductions in Supplier's charges shall be implemented effective as of January 1st of the year following the commencement of the Benchmarking.

8.5 Invoices

(a) Except as otherwise expressly provided herein, the Supplier shall invoice the Client monthly. All invoices submitted under this Agreement shall contain a description of the period to which such invoice relates, an itemized statement of the Services performed and the price, as applicable, of each Service or Change Request. Invoices shall be prepared and sent by the Supplier to the Client in each month following the month in which the Services are provided or the Fees, Pass Through Charges and any additional expenses are incurred.

(b) Subject to Section 8.7 (Additional Expenses), the Client shall pay, without set-off or deduction, all invoices within thirty (30) calendar days from the date of receipt of the relevant invoice. If the Client disputes the amount of any invoice, or any part thereof, the Client shall pay the invoice in full, including such disputed amounts. In the event it is determined that the disputed amount or any part thereof is not payable by the Client hereunder, the Supplier shall reimburse the Client, together with Interest thereon calculated from the date such payment was made by the Client to the date the Client is reimbursed by the Supplier.

(c) Upon the occurrence of a Service Credit, the Supplier will issue a credit invoice to the Client in the following month in which the Service Credit occurred and calculated in accordance with Section 2.8 (Service Credits).

(d) Upon the Supplier meeting the conditions as set out in Section 2.6 (Service Level Methodology and Performance Indicators), the Supplier, in the month following will invoice the Client the same amount as the original Service Credit.

(e) If the Client fails to pay any amount when due hereunder, the Supplier shall have the option to:

(i) charge Interest on such overdue amount from the date due until payment is received by the Supplier; and

(ii) charge the Client for the Supplier's costs of collecting all past due amounts including reasonable legal fees and disbursements.

(f) Invoices shall be forwarded to the address and person designated by the Client.

8.6 Taxes

The Client shall pay all taxes (including sales, use, consumption, value added, goods and services and similar taxes), duties, rates or levies of any nature whatsoever imposed upon, arising out of or in respect of this Agreement or the Services to be performed hereunder (excluding taxes on the Supplier's net income, gain or capital of the Supplier, and payroll taxes/deductions applicable to the Supplier's Representatives). Where the Supplier pays such taxes or levies, or has the obligation to collect the same, the same shall be added to any invoices issued by the Supplier hereunder and shall be remitted to the Supplier by the Client.

8.7 Additional Expenses

The Client shall be responsible for any additional fees, expenses or other charges by the Supplier associated with the failure of the Client, its Representatives or a Third Party retained by the Client, to fulfill in a timely manner any of the Client's obligations pursuant to this Agreement (the "**Additional Expenses**"), provided the Additional Expenses are reasonable in the circumstances.

8.8 Financial Responsibility

The Client shall have financial responsibility for all costs and expenses related to each item which is to be provided by the Client under this Agreement. Except as otherwise specifically provided under this Agreement, the Supplier shall have financial responsibility for all costs and expenses related to each item which is to be provided by the Supplier under this Agreement.

ARTICLE 9
WARRANTIES AND LIABILITIES

9.1 Corporate Warranties

In addition to the representations and warranties given by each Party elsewhere in this Agreement, each Party represents and warrants to the other that:

(a) it is a corporation duly incorporated or organized, validly existing and in good standing under the Laws of its place of incorporation or registration; it is properly

qualified where qualification is necessary for the conduct of its business; and it has adequate corporate or other power to enter into and perform this Agreement;

(b) this Agreement has been duly executed and delivered by such Party and (assuming the due authorization, execution and delivery hereof by the other Party) is a valid and binding obligation of such Party, enforceable against it in accordance with its terms;

(c) the execution and delivery of this Agreement, and its performance by such Party of all its obligations set forth in this Agreement are not limited or restricted by, and are not in conflict with or a violation of any Law, decree, judgment, contract or other instrument to which it is a Party or by which it is bound, and shall not infringe upon or violate the right of any Third Party;

(d) it is free, as of the date hereof, of any material contractual or statutory rights or obligations in favour of any Third Party that would prevent or impair it from entering into and fulfilling its obligations under this Agreement, and further is unaware of any facts that would prevent it from performing its obligations under this Agreement; and

(e) it is not a non-resident of Canada for purposes of the *Income Tax Act* (Canada) and it will provide prior notice to the other Party of any change in this status.

9.2 Supplier Warranty

The Supplier covenants and warrants to the Client that it will perform its obligations under this Agreement (i) in a timely, workmanlike, competent, conscientious and professional manner, (ii) in accordance with generally accepted standards of care in the distribution energy customer care and billing services industry, and (iii) in conformity with this Agreement, including the Service Levels prescribed herein.

9.3 Remedy

(a) The Parties acknowledge and anticipate that in the normal course of business, acts or omissions commonly experienced from time to time in the customer care and billing industry regarding the provision of similar or like services as the Services provided under this Agreement will occur, and in such event, the Supplier shall, to the extent practicable and as would be consistent practice in the customer care and billing industry, re-perform the Services which were not provided in accordance with the standards set forth in Section 9.2 (Supplier Warranty).

(b) In respect of Claims arising as a result of a Material Breach of the Supplier's warranty in Section 9.2 (Supplier Warranty) or otherwise giving rise to the Client's right of termination in Section 13.2 (Early Termination Events), or the gross negligence or willful misconduct of the Supplier, the Parties acknowledge and agree that the Client is not restricted to the remedy provided in Section 9.3(a), subject always to the limitations and exclusions of liability set forth in this Agreement, including Sections 9.4 (Limitation of Liability), 9.5 (Exclusion of

Liability), 9.6 (Limitation of Warranties) and 9.11 (Mutual Exclusion of Liability).

(c) Without limiting the Client's other rights and remedies pursuant to other provisions of this Agreement and in particular Section 15.15 (Remedies Cumulative) and including those related to a Material Breach and subject to subsections 9.3(a) and (b) hereof, the Parties agree that if the Supplier fails to meet an obligation in this Agreement that gives rise to a Service Credit as contemplated by Section 2.8 (Service Credits), the Client's exclusive remedy for such failure shall be limited to such Service Credit.

9.4 Limitation of Liability

Notwithstanding any other provision of this Agreement:

(a) the Supplier shall not be held liable for, and the Client hereby releases the Supplier from, any and all Claims, including those arising out of any faults, interruptions or delays in the Services or out of any inaccuracies, errors or omissions in the information provided to the Client, its Retailers, Site Customers, Site Contacts, Site Owners or other persons in connection with the Services, except as provided for in Section 9.3 (Remedy), unless due to the Supplier's willful misconduct or gross negligence;

(b) the Supplier's total liability pursuant to this Agreement shall not in any event exceed the Liability Cap;

(c) provided however, that the limitations on liability contained in Section 9.4(b) shall not apply to:

(i) unauthorized disclosure of Confidential Information; or

(ii) breach of a warranty relating to IP Rights and/or to any requirement to indemnify for IP Rights infringement.

9.5 Exclusion of Liability

In addition to any other exclusions or limitations of liability set out in this Agreement, the Supplier shall be relieved of, and the Client hereby releases the Supplier from, the obligation to perform hereunder and from liability for any failure or delay in performing any of the Services, including any failure in meeting any of the Service Levels, or related to a failure of or delay by the Client to meet any obligations it may have to any person (including Retailers, Site Customers, Site Contacts, Site Owners or other persons):

(a) to the extent that such failure or delay is caused, directly or indirectly, by the failure or delay of the Client, its Representatives or a Third Party retained by the Client (other than Representatives of the Supplier) in performing its obligations set out in this Agreement, including any breach of a representation or warranty of

the Client or where actual volumes fall outside the assumptions set forth in Schedule B (Service Levels), revised by the Supplier from time to time;

(b) where the Client has requested the Supplier to perform Services on an expedited basis without providing the Supplier adequate preparation and testing time to implement such Services; or

(c) to the extent that such failure or delay is caused, directly or indirectly, by a Change in Law.

9.6 Limitation of Warranties

The representations, warranties, covenants, terms or obligations provided in this Agreement are exclusive and are in lieu of any other understandings, representations, warranties, covenants, conditions, promises, guarantees or agreements, whether express, implied, statutory or otherwise, and whether arising from a course of dealing or usage of trade, relating to the Services or any Deliverables, including any warranty of merchantability or fitness or adequacy for any particular purpose or use, or of quality, productiveness, capacity or accuracy and only the express terms and conditions contained in this Agreement shall be binding upon Supplier and the Client. The Parties agree, accept and confirm that all such other representations, warranties, conditions, covenants, provisions and guarantees are expressly denied and disclaimed, and that such denial and disclaimer is fair and reasonable in the circumstances of this Agreement.

9.7 Appointment of an Interim Administrator

(a) In the event that all of the following conditions have both been satisfied, namely:

(i) the Client has provided notice to the Supplier:

(A) stating that it is terminating this Agreement purportedly in accordance with Section 13.2 (Early Termination Events); and

(B) including a statement setting forth all particulars of its damages, including a quantification of its damages in reasonable detail; and

(ii) the Client has posted an irrevocable Letter of Credit issued by a Canadian chartered bank, trust company, credit union or other lending institution acceptable to the Supplier and in substance and form satisfactory to the Supplier for an amount equal to the Supplier's reasonable estimate of the amounts payable by the Client under Section 13.5 (Effect of Termination), unconditionally payable upon presentment by the Supplier of an Award in respect of a Claim by the Supplier against the Client, or an Award determining that the Supplier has not committed a Material Breach of this Agreement;

then the Client may elect to appoint a Representative (the "**Interim Administrator**") to assume the responsibility, effective upon the date that notice of such appointment is provided to the Supplier (the "**Interim Administrator**

Notice"), and whom the Supplier acknowledges (subject to the conditions herein being satisfied) shall have the authority, to provide reasonable direction to the President of the Supplier (but not to any other Representative of the Supplier) in respect of its performance of the Services during the period specified by the Client (the "**Interim Period**"), but in no event for longer than sixty (60) days.

(b) Notwithstanding the foregoing, in no event shall any direction by the Interim Administrator interfere in any material respect with the Supplier's conduct of its business (other than in respect of the Services during the Interim Period), including the provision of products and services of any nature whatsoever to its other clients.

(c) Nothing in this Agreement, including this Section 9.7, shall permit the Client, including the Interim Administrator, to assume performance of the Services, nor in any way abrogates any restrictions or limitations on the Client and its Representatives in respect of Confidential Information or IP Rights or otherwise abrogates the Client's obligations hereunder, including payments due hereunder.

(d) For clarity, in the event the Client elects to appoint an Interim Administrator hereunder, Section 2.3 (Compliance with Applicable Law) shall continue to apply, and the President of the Supplier shall not be required to undertake, or cause the Supplier or its Representatives to undertake, any activity that would conflict with the requirements of any Laws, regulatory approval, permit or obligation of confidentiality owed to any person, including to vendors or licensors.

(e) In the event the Client elects to appoint an Interim Administrator hereunder, the Supplier may, in its Discretion, upon receipt of an Interim Administrator Notice, elect to immediately terminate the Agreement, in which case the provisions of Sections 13.5 (Effect of Termination) and 13.6 (Transition Plan for Termination) shall apply.

9.8 Client Warranties

The Client represents and warrants to and covenants with the Supplier that:

(a) the Client has not engaged any other person to, or entered into any agreement, arrangement or other understanding with, or granted any right, whether contingent or vested, to any other person, to perform the Services or services comparable thereto;

(b) the Client has the right to deliver the Client Data to the Supplier and the right to permit the Supplier and its Representatives to use the Client Data, the Client's Systems and all parts thereof as contemplated herein;

(c) subject to Section 3.2 (Compatibility of Client's Systems), the Client's computer systems and all components thereof are compatible with the Supplier's Systems;

(d) the Client shall take reasonable steps and utilize available means and practices, in keeping with generally accepted standards and practices in the distribution customer care and billing services industry, to prevent, search for, detect and eliminate any Computer Viruses in the Client's Systems, in any electronic data (including the Client Data) being introduced into the Supplier's Systems, or which could otherwise interfere in the performance of the Services;

(e) the Client has the expertise, personnel, experience, skill, resources, facilities, equipment and business capacity to fulfill its obligations hereunder, including all obligations necessary to enable the Supplier to perform the Services in accordance with the provisions of this Agreement.

9.9 Indemnities

(a) Cross Indemnity. Subject to the express limitations and exclusions of liability elsewhere in this Agreement, the Supplier and the Client, as the case may be (the "**Indemnitor**") each agree to indemnify, defend and hold harmless the other Party (including any Indemnified Persons of the other Party) (the "**Indemnitee**") from any and all Claims arising out of the gross negligence or willful misconduct of the Indemnitor other than, and there is hereby excluded from the indemnity pursuant to this Section 9.9(a), any matter covered by the indemnity in Section 9.9(b).

(b) Intellectual Property Warranty and Indemnity. Each Party (the "**IP Indemnitor**") warrants that its work performed under this Agreement, and additionally in the case of the Supplier that the provision of the Services, including any Deliverables (excluding any Third Party components), and additionally in the case of the Client, any data (including Client Data), Software, material or other content provided to the Supplier for use in providing the Services (including any Deliverables), shall be free of any Claim of any Third Party for infringement of any applicable IP Rights. Notwithstanding the foregoing, or any other provision(s) of this Agreement, neither Party makes any representation or warranty whatsoever, and expressly disclaims any such representation or warranty, express or implied, statutory or otherwise, in respect of ATCO-CIS, including those related to merchantability, fitness for a particular purpose, durability or that any use of ATCO-CIS will not infringe or constitute wrongful use of any patent, copyright, trade secret right or any other right of a Third Party protected under law or equity, or otherwise infringe the IP Rights of any person.

Subject to the express limitations and exclusions of liability elsewhere in this Agreement, if notified promptly in writing and given authority, information and assistance, the IP Indemnitor shall indemnify and save harmless the other Party (the "**IP Indemnitee**") from any Claim against the IP Indemnitee so far as based on a claimed infringement which would result in a breach of the warranty in this Section 9.9(b) (the "**IP Claim**").

If the use of any of the Services is enjoined, or if the Supplier reasonably believes that the Services may be enjoined, the Supplier shall, at its sole option and expense either:

(i) obtain the right to continue providing the Services;

(ii) modify the Services so that it no longer infringes;

(iii) provide the Client with reasonable alternate Services, as applicable, providing substantially the same features, functions and capability; or

(iv) if none of the foregoing options can be done on reasonable commercial terms, the Supplier may terminate the enjoined Services without any liability to the Client whatsoever for such termination, except as provided for in this Section 9.9(b).

The foregoing sets out the entire liability of the Supplier and the sole obligations of the Supplier to the Client in respect of any Claim that the Services infringe any Third Party rights, including any IP Claim.

(c) Compliance with Laws. Subject to the express limitations and exclusions of liability elsewhere in this Agreement, each Party shall indemnify, hold harmless and defend the other Party and its Indemnified Persons from and against any and all Claims of whatsoever nature caused by or arising out of the indemnifying Party's failure or the failure of its Representatives to comply with Laws, including any additional costs for Services that must be re-performed as a result.

(d) Consents. Each Party shall indemnify, hold harmless and defend the other Party and its Indemnified Persons from and against any and all Claims of whatsoever nature caused by or arising out of its failure to obtain the consents contemplated by Section 6.4.

9.10 Procedure – Indemnities

If an Indemnitee or an IP Indemnitee (the "**Claiming Party**") wishes to claim indemnification from a Party (the "**Indemnifying Party**") pursuant to this Agreement in respect of a Claim brought against the Claiming Party by a Third Party, it shall, as a condition to its entitlement to be paid in respect of such indemnity:

(a) provide prompt notice upon acquiring knowledge of the subject matter of the Claim (the "Indemnified Claim"); provided that failure to give such notice shall not limit or lessen the right of the Claiming Party to indemnity hereunder except to the extent that the Indemnifying Party is prejudiced in its contestation of the Indemnified Claim as a result of such failure;

(b) if reasonably requested by the Indemnifying Party within thirty (30) days from receipt of the notice referred to in Section 9.10(a) or such shorter period as the Claiming Party has notified the Indemnifying Party is required by Applicable Law

to commence such contest, and provided that the Indemnifying Party has acknowledged to the Claiming Party that the Indemnified Claim is covered by the indemnity herein, the Claiming Party shall at the expense of the Indemnifying Party in good faith contest the validity, applicability or the amount of such Indemnified Claim by all reasonable proceedings or, at the option of the Indemnifying Party, the Indemnifying Party shall be entitled to conduct such contestation or, if the contestation thereof is not in the control of the Claiming Party, exercise any rights to vote (by ballot or otherwise) in respect of the Indemnified Claim as instructed by the Indemnifying Party from time to time;

(c) in the event of any contest of any Indemnified Claim, whether by the Indemnifying Party or the Claiming Party, the other Party shall provide all such assistance, including access to documents and officers and employees, as may be requested by the Party conducting the contestation of the Indemnified Claim and the other Party shall be entitled (at its own expense) to be represented by separate counsel in the contestation;

(d) neither Party shall settle or agree to pay or, if the settlement or contestation of such Indemnified Claim is not in the control of the Party, exercise any rights to vote (by ballot or otherwise) in favour of a settlement or agreement to pay, the Indemnified Claim without the consent of the other, such consent not to be unreasonably withheld; and

(e) if the Indemnifying Party has paid an amount in respect of an Indemnified Claim pursuant hereto, then (i) the Indemnifying Party shall be subrogated to all and any Claims which the Claiming Party may have relating thereto without any further action; (ii) the Claiming Party, without limiting its rights to the indemnity herein, shall give such further assurances and agreements and cooperate with the Indemnifying Party to permit the Indemnifying Party to pursue such Claims as and when requested by the Indemnifying Party; and (iii) if the Claiming Party shall subsequently be reimbursed from any source in respect of the Indemnified Claim from any other person, the Claiming Party shall promptly pay to the Indemnifying Party such amounts received, including interest actually received attributable thereto.

9.11 Mutual Exclusion of Liability

Except as otherwise expressly provided in this Agreement, neither Party shall in any event be liable for any indirect, incidental, special, consequential, exemplary or punitive damages whatsoever (including lost profits or savings, loss of use, cost of capital, or down time costs) occurring out of or in connection with the delivery, use, performance or failure of the Services (including any Deliverables) or Systems, or directly or indirectly arising from any breach of this Agreement (including fundamental breach) or from the negligence, gross negligence or willful misconduct of that Party, its Representatives or the Indemnified Persons, even if advised of the possibility of such damages.

9.12 Not Penalty/Liquidated Damages

All compensatory obligations and other remedies (whether financial or otherwise) expressly provided in this Agreement shall not constitute, nor are they intended by either Party to be, penalties or to be punitive against the Supplier. Both Parties agree and confirm that all such remedies are liquidated damages to compensate the Client for losses and damages that will immediately be incurred by the Client in the event of such breaches of this Agreement that are not possible to quantify or empirically determine, and that the remedies constitute a fair and reasonable estimate of the proximate and direct harm, loss and damage that the Client shall suffer and incur in any such occurrence. The Supplier and the Client agree and acknowledge that the remedies are justified, necessary and reasonable in the commercial and international circumstances of this Agreement, and that all such remedies constitute a material inducement for the Client to enter into this Agreement.

ARTICLE 10
INSPECTIONS, CONTINUOUS IMPROVEMENT, AUDITS AND SECURITY

10.1 Maintenance of Records

During the Term of this Agreement and for two (2) years following expiry or termination, the Supplier shall maintain the previous two years' records and documents, including proper time sheets, accounts and invoices, necessary for the Client to verify the accuracy of invoices issued by the Supplier hereunder for Services provided on a Time and Materials Rate basis, Additional Expenses and Pass Through Charges (collectively, "**Records**"). The Records shall be available, upon reasonable notice, for review and inspection by the auditors of the Client (under strict terms of confidence and only disclosing the amount and nature of any discrepancy between the Time and Materials Rate, Additional Expenses and Pass Through Charges invoiced and those that are chargeable) during Business Hours.

10.2 Inspections and Audits

(a) No more than once per year, and upon fifteen (15) Business Days notice, the Client shall be entitled, at its sole cost and expense, under strict terms of confidence and subject to Applicable Laws, and in accordance with the Supplier's security procedures, during Business Hours, to audit the Client Data and to escorted access to facilities from which Services are performed to the extent necessary to verify:

(i) the accuracy of charges made on a Time and Materials Rate basis, and for Additional Expenses and Pass Through Charges;

(ii) that the security procedures and standards of care being practiced by the Supplier are consistent with its obligations under this Agreement;

(iii) that the Services are being provided in accordance with this Agreement;

(iv) that the reporting of Service Levels is accurate; and

(v) the Supplier business continuity plan in effect from time to time;

provided any such audit or escorted access does not unduly interfere with the Supplier's ability to perform the Services or to provide services to other clients.

(b) The Supplier shall promptly reimburse the Client without set-off or deduction for any error detected pursuant to an audit hereunder in amounts charged to the Client, together with Interest thereon from the date the payment was made by the Client until reimbursed by the Supplier.

10.3 Continuous Improvement

From time to time, the Client may request that the Supplier assist with specific issue analysis activities, the identification and/or management of process improvement opportunities, verification of data and/or quality controls. To the extent possible, the Client will provide notice of any such requirements at the quarterly Management Committee meetings. The Supplier will develop a proposal to provide the requested support. To the extent that the Client request can be met using existing Supplier resources, without adversely affecting normal Supplier operations, this assistance will be provided at no additional cost up to a maximum of sixty (60) hours per year of Supplier time. All other such requests will be addressed through a Change Request.

10.4 Exclusions

In the course of any audit, monitoring or inspection conducted under this Article 10 (Inspections, Continuous Improvement, Audits and Security), the Supplier will provide escorted access only to Records and Recordings and such facilities that are directly related, and are reasonably necessary, to perform the inspection, audit or monitoring permitted pursuant to Sections 10.1 (Maintenance of Records), 10.2 (Inspections and Audits) and 10.3 (Continuous Improvement), provided however that the Supplier will not allow the Client or its Representatives (including auditors) access to:

(a) data other than Client Data or data required to evaluate the items described in paragraphs 10.2(a)(i) to 10.2(a)(v) (Inspections and Audits);

(b) any proprietary data or Confidential Information of the Supplier, its suppliers or other clients;

(c) on an unescorted basis, areas which do not form part of the facilities used by the Supplier exclusively to provide the Services to the Client; or

(d) business or accounting records of the Supplier other than the Records or Recordings.

Neither the Client nor its Representatives (including auditors) shall use any electronic recording device of any kind, including audio recorders, scanners or copiers during any inspection or audit

under this Article 10 (Inspections, Continuous Improvement, Audits and Security) without the express written permission of the Supplier.

10.5 Charges

Each year during the Term of this Agreement, the Supplier shall provide up to forty (40) hours of employee time to assist the Client's auditors under Sections 10.1 (Maintenance of Records) and 10.2 (Inspections and Audits). The Client shall pay the Supplier at its Time and Materials Rate for all employee time in excess of such forty (40) hours per year in respect of Sections 10.1 (Maintenance of Records) and 10.2 (Inspections and Audits) for the sixty (60) hours per year of employee time in respect of Section 10.3 (Continuous Improvement), and for all expenses incurred by the Supplier in respect of this Article 10 (Inspections, Continuous Improvement, Audits and Security), except if such inspection or audit pursuant to Sections 10.1 (Maintenance of Records) and 10.2 (Inspections and Audits) reveals that the Supplier is in material breach of its obligations under this Agreement.

10.6 Security Practices

(a) The Supplier's security practices in relation to Client Data will conform with generally accepted standards in the customer care and billing services industry. If deficiencies are identified by the Client as a result of inspections, audits or otherwise, the Supplier shall implement such additional security practices as are consistent with such standards. To the extent that the security practices are in compliance with generally accepted standards in the customer care and billing services industry, the Supplier shall not be liable to the Client for any Claims that may occur or arise as a result of a security breach. At the Client's request, the Supplier will provide reasonable assistance in identifying, tracking and closing security loopholes.

(b) The Supplier shall take reasonable steps and utilize available means and practices, in keeping with generally accepted standards and practices in the energy distribution customer care and billing services industry, to prevent, search for, detect, and eliminate any Computer Viruses in the Supplier's Systems, in any electronic data being introduced into the Client's Systems by the Supplier or which could otherwise interfere with the performance of the Services.

(c) The Supplier's obligations in respect of the Client Data pursuant to this Agreement, including this Article 10 (Inspections, Continuous Improvement, Audits and Security), shall not arise until the Supplier has received the Client Data and the Client Data has been implemented into the Supplier's System, and shall be subject to the Client's obligations under this Agreement, including the Client's obligations set forth in Section 6.2 (Client Data).

ARTICLE 11
OWNERSHIP

11.1 Client Data

The Supplier agrees that Client Data is, and shall remain, the exclusive property of the Client at all times, and shall be held by the Supplier in trust for the sole benefit of the Client. The Client, its Representatives and Third Parties designated by it shall be permitted electronic access to all Client Data at all times, which access shall not be denied by the Supplier for any reason whatsoever (except when access is unavailable during reasonable periods of repair or maintenance), provided that such access must be exercised subject to the ATCO Group's security standards and such commercially reasonable terms and conditions imposed by the Supplier (including those relating to read-only access and the cost of access), as revised from time to time.

11.2 Supplier's Systems

The Client agrees that the Supplier may process the Client Data through the Supplier's Systems and/or the Systems of Third Party suppliers, and may otherwise use the Client Data as required to provide the Services or as provided for in this Agreement. The Supplier's Systems, including any associated IP Rights therein, are and shall remain the exclusive property of the Supplier and/or its Third Party licensors or suppliers of such Systems.

11.3 Client's Systems

Commencing on the Effective Date, the Client grants to the Supplier and to those of the Supplier's Representatives involved in the provision of Services a royalty-free license (or will obtain for the Supplier a royalty-free license) to install and use on the Supplier's Systems the Software specified from time to time in Schedule D (Client's Systems), for the purpose of accommodating the Supplier's provision of the Services to the Client. The Client's Systems, including any associated IP Rights therein, are and shall remain the exclusive property of the Client and/or its Third Party licensors or suppliers of such Systems.

(a) The Client's Systems, including any associated IP Rights therein, are and shall remain the property of the Client or the Third Party licensors or suppliers of such Systems. For any Client's Systems owned by the Client that will be used by the Supplier to provide the Services, the Client grants to the Supplier the right to use such Client's Systems solely in connection with the Services. For Client's Systems licensed from Third Parties, the Client will use all commercially reasonable efforts to obtain permission from the licensors of such Systems to permit the Supplier to operate such Systems, subject to the terms and conditions of the existing licenses and subject to the restriction that such Systems be used solely to permit the Supplier to provide the Services. The Supplier shall not:

(i) allow Client's Systems to be disclosed, sold, assigned, leased, copied or otherwise disposed of or commercially exploited by the Supplier, its Representatives or Third Parties; and

(ii) use any Client's Systems on its own behalf or on behalf of any unrelated Third Party without the prior written consent of the Client, the Supplier shall not remove or destroy any markings or legends placed upon any Client's System or documentation thereof, and shall reproduce such markings or legends if copies are made of Client's Systems or such documentation. The Supplier further agrees to comply fully with any restrictions or obligations of which the Supplier is made aware, including any licensing or nondisclosure obligations, imposed by any Third Parties on the use of Client's Systems, and to execute such non-disclosure agreements as may be reasonably required by the Third Party licensors of Client's Systems.

(b) If the Client has been unable to obtain any one or more of the permissions contemplated by this Section 11.3 (Client's Systems) or Section 6.4 (Supplier Access to the Client's Systems) then, where reasonable in the circumstances and where deemed appropriate by the Client, the Client will either obtain substantially equivalent Systems or accept a reduction in Services to the extent necessary to reflect the Supplier's inability to use such Systems until permission is obtained. The applicable charges will be adjusted to reflect any reduction in Services.

(c) Unless the Client otherwise agrees in a Change Request (complete and incomplete), the Client shall own all new developments, Deliverables and/or know-how and all IP Rights therein (including without limitation, all new custom designed programs and all improvements, enhancements and modifications to existing or new custom designed programs and all new Supplier software and all new improvements, enhancements and modifications thereto), which arise out of or are otherwise created during the course of or as a consequence of providing the Services; provided that, in respect of any particular new development, Deliverables, know-how and/or IP Rights, it was funded substantially by the Client or by a combination of the Client and one or more other utilities affiliated with the Client. In all other cases, IP Rights shall vest with the Supplier. Each Party agrees to execute (and to obtain the agreement of its Representatives to execute) all additional agreements, instruments or documentation reasonably required to give effect to this provision.

11.4 Documentation

The Supplier will supply the Client with such Documentation applicable to the Services as may be set out in a Schedule or Change Request. Any Documentation relating to the Supplier's Systems and/or the Services, including any associated IP Rights therein, is and shall remain the exclusive property of the Supplier. The Supplier grants the Client a limited, non-exclusive, non-transferable license to permit use by the Client and its Representatives of such Documentation during the Term and in support of the provision of the Services.

11.5 Prohibited Uses

The Client agrees it shall not, nor shall it permit any Third Party to, use its Access to the Supplier's Systems or any associated Documentation relating to the Services or the Supplier's Systems, other than its Representatives with a need to Access such Systems and use such Documentation, and strictly in support of the Services or other purposes authorized or permitted hereunder or under the System Access Terms. Any such Access shall be subject to the requirements set out in Section 6.3 (Client Access to the Supplier's Systems). The Client agrees it shall not, nor shall it permit any Third Party to, use the Client's access to the Supplier's Systems or any Documentation relating to Services or Supplier's Systems for the purpose of developing a competing System that is intended to provide functionality similar to Supplier's Systems and/or Services.

11.6 Supplier Know-How

The Client acknowledges and agrees that the Supplier, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms used in the provision of the Services hereunder or relating to the conduct or operation of its business, whether patentable or not ("**Supplier Know-How**"). The Client further acknowledges and agrees that such Supplier Know-How constitutes confidential, valuable proprietary information and trade secrets of Supplier or its suppliers and that Supplier shall retain exclusive ownership of such Supplier Know-How, including any applicable IP Rights therein.

11.7 Client Know-How

The Supplier acknowledges that the Client, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms relating to the conduct or operation of its business, whether patentable or not, ("**Client Know-How**"). The Supplier acknowledges and agrees that such Client Know-How constitutes confidential, valuable proprietary information and trade secrets of the Client or its suppliers and that the Client shall retain exclusive ownership of such Client Know-How, including any applicable IP Rights therein.

ARTICLE 12
CONFIDENTIALITY

12.1 Meaning of Confidential Information

For the purposes of this Agreement, "Confidential Information" means any information or data obtained by a Party (a "**Recipient**") from the other Party (the "**Disclosing Party**") as a result of this Agreement, including proprietary, technological, technical, developmental, marketing, sales, distribution, operating, performance, cost, know-how (as set forth in Sections 11.5 (Prohibited Uses) and 11.6 (Supplier Know-How) hereof), business and process information, computer programming techniques and methods, all record-bearing media

containing or disclosing such information and techniques, financial information or reports, market studies, contracts, engineering reports, technical and economic data, marketing terms and arrangements, plans, maps, drawings, computer records or software, specifications, models, algorithms, works of authorship, inventions, innovations or improvements in any device, process or thing, whether patentable or not, proposed services to be offered or strategic alliances entered into or to be entered into, and similar business, financial and proprietary information, in whatever form or medium, including:

(a) the commercial terms of this Agreement;

(b) relating to such Party's Software or hardware products and services, or to its research and development projects or plans, and including in the case of the Supplier, Supplier Know-How, Documentation and the Supplier's Systems and associated documentation, and including in the case of the Client, the Client's Systems and associated documentation, Client Data and Client Know-How;

(c) relating to such Party's trade secrets, business policies, strategies, operations, processes, finances, plans or opportunities including the identity of, or particulars about the foregoing;

(d) any of the foregoing types of information relating to such Party's clients or suppliers; and

(e) information marked or otherwise identified as confidential, restricted, secret or proprietary including information made available to the Recipient for inspection or by oral disclosure provided such information is identified as confidential at the time of disclosure or inspection and the Disclosing Party promptly provides the Recipient with written confirmation summarizing the Confidential Information disclosed.

Each Recipient agrees not to remove, cover, deface or alter any copyright, trade secret or trade mark notices contained on the Confidential Information.

12.2 Confidentiality of Agreement

Except where either Party is required to disclose any provision of this Agreement in order to exercise any right or to perform any obligation hereunder, and subject to any requirement for disclosure under Applicable Law and to Section 12.5 (Permitted Disclosure), neither Party shall disclose the terms and conditions of this Agreement to any other person, unless expressly agreed by the other Party.

12.3 Disclosure to Representatives

Each Recipient agrees to disclose the Confidential Information only to those of its Representatives who have a need to know the information and who are aware of the Recipient's obligations of confidentiality under this Agreement, have agreed in writing to be bound by such obligations or who are under enforceable obligations of confidence in respect of the Confidential Information that are as strict or stricter than the obligations of the Recipient hereunder. The

Confidential Information shall not be used by the Recipient for any purpose other than to perform the Recipient's obligations under this Agreement.

12.4 Permitted Use

Each Recipient agrees to disclose the Confidential Information only to those of its Representatives who have a need to know the Confidential Information, and who are under a written and enforceable obligation to keep confidential the Confidential Information received from the Disclosing Party and to use the Confidential Information only for the purposes described in this Agreement. Client Data shall not be used by Supplier for any purpose other than to provide the Services to the Client. Each Recipient will, prior to disclosing the information to its Representatives, advise them of its obligations under this Article 12 (Confidentiality). Upon request, each Recipient agrees to provide the Disclosing Party with a list of the Recipient's Representatives who have been provided with access to the Confidential Information of the Disclosing Party.

12.5 Permitted Disclosure

Notwithstanding the foregoing, the Recipient shall not be obligated to comply with the obligations in this Article 12 (Confidentiality) relating to Confidential Information which:

(a) the Recipient can prove was known to the Recipient at the time of disclosure as evidenced by written documents in the possession of the Recipient;

(b) in the case of the Supplier as a Recipient of Client Data, any Client Data that is provided to the Supplier to be used by the Supplier to provide Services to a Retailer in its capacity as a Retailer;

(c) is available to the general public at the time of disclosure to the Recipient or is subsequently made available to the general public without fault of the Recipient;

(d) is disclosed or becomes available to the Recipient by reason of any act of any Third Party having the right to disclose or publicize it;

(e) is intentionally distributed without restrictions as to confidentiality by the Disclosing Party;

(f) is required to be disclosed in connection with the conduct of any arbitration or court proceeding carried out pursuant to this Agreement, provided that such disclosure is made pursuant to and in accordance with the approval and at the direction of the arbitrators conducting such arbitration or applicable judicial officers and provided both Parties hereto use their commercially reasonable efforts to have such arbitrators execute confidentiality agreements, the terms of which are similar to those set out herein;

(g) is required to be disclosed by operation of Law, provided that:

(i) the Commission, court or other tribunal of competent jurisdiction has ordered that such Confidential Information be disclosed;

(ii) the Recipient uses its commercially reasonable efforts to maintain the confidentiality of all commercially sensitive materials comprising Confidential Information (including any information that the Disclosing Party, in its Discretion, deems sensitive to its competitive position in the industry, or is otherwise valuable to the Disclosing Party), and such efforts shall include commercially reasonable efforts to impose confidentiality obligations upon the person to whom disclosure is required by operation of Law (including to the Commission, where applicable); and

(iii) the Recipient provides to the Disclosing Party immediate notification of any such requirement for disclosure;

(h) is disclosed to the Recipient's professional advisors or in connection with the possible sale of the Recipient's assets or business or to the Recipient's investment bankers or commercial bankers in connection with any financing provided that each such Third Party recipient has agreed in writing to maintain the confidentiality of the Confidential Information on terms as strict or stricter than the Recipient's obligations hereunder.

12.6 No Breach for Use of General Knowledge

Both Parties acknowledge and agree that their Representatives, during the course of performing or obtaining the Services, may develop their general knowledge, skills and experience as they relate to data processing. The subsequent use by either Party or its Representatives of such general knowledge, skills and experience relating to data processing in the ordinary course of business will not constitute a breach of the confidentiality provisions contained in this Agreement.

12.7 Injunctive Relief

Each Recipient acknowledges and agrees that any use or disclosure of Confidential Information of the Disclosing Party in a manner inconsistent with the provisions of this Agreement may cause the Disclosing Party harm which cannot be compensated by monetary damages alone and, accordingly, each Disclosing Party will, in addition to other available legal or equitable remedies, be entitled to seek an immediate injunction restraining the Recipient and its Representatives from committing or continuing to commit a breach of this Article 12 (Confidentiality). In such event, the Disclosing Party applying for injunctive relief need not show or prove any actual damage sustained by it and may avail itself of injunctive relief in addition and without prejudice to any other remedies available to it.

12.8 Return of Information

Promptly upon termination, or such earlier date upon which Confidential Information of the Disclosing Party is no longer required by the Recipient for the purposes of this Agreement, the Recipient shall return the Confidential Information to the Disclosing Party and, subject to the

Recipient's obligations pursuant to Applicable Law, shall erase all other copies of such Confidential Information in the possession or control of the Recipient or its Representatives.

12.9 Publicity

Each Party will submit to the other all advertising, sales promotion, press releases and other publicity matters relating to this Agreement in which the other Party's name, logo, trademark or other mark is mentioned or language from which the connection of said name, logo, trademark or other mark may be inferred or implied, and will not publish or use such advertising, sales promotion, press releases or publicity matters without the prior written approval of the other Party. However, either Party may include the other Party's name and a general factual description of the work performed under this Agreement in employee bulletin boards, in its lists of references and in the experience section of proposals to Third Parties, in internal business planning documents and communications, and in annual reports to shareholders of the Party or its parent and whenever required by reason of legal, accounting or regulatory requirements.

12.10 Assistance

The Recipient shall notify the Disclosing Party promptly if it becomes aware or has reasonable grounds to suspect that unauthorized disclosure of Confidential Information of the Disclosing Party has occurred or is likely to occur. The Recipient shall, at the request of the Disclosing Party and at its own expense, use commercially reasonable efforts to assist the Disclosing Party in identifying any use, copying or disclosure of any Confidential Information by any present or former Representative of the Recipient in any manner contrary to the provisions of this Agreement, so long as the Disclosing Party shall have provided the Recipient with information reasonably justifying the conclusion of the Disclosing Party that such contrary usage may have occurred.

ARTICLE 13
TERM AND TERMINATION

13.1 Term and Renewal

(a) Subject to Section 13.2 (Early Termination Event), this Agreement shall be in effect for a term commencing on the Effective Date and ending on the sixth(6^{th}) anniversary of the Effective Date (the "**Term**").

(b) Starting on the fourth (4th) anniversary of the Effective Date, the Parties will enter into negotiations regarding renewal of the Agreement for a new six (6) year term effective on the fifth anniversary of the Effective Date.

(c) In the event that the preceding activity has not been undertaken and no later than eighteen (18) months prior to the end of the Term (or as soon thereafter as may be reasonably practical for Supplier), Supplier will send the Client a notice (the "**Renewal Notice**") requesting that the Client advise Supplier if the Client does not wish to renew this Agreement following the expiry of the Term. If the Client does not respond in writing to the Renewal Notice within thirty (30) days

following the date of the Renewal Notice, this Agreement will be automatically renewed for six (6) years on the fifth anniversary of the Effective Date on the same terms and conditions *mutatis mutandis*, including, without limitation, then prevailing pricing as adjusted through the Term and the obligations to review and/or adjust pricing all of which shall be applicable during the renewal term of the Agreement.

(d) If either Party elects not to extend the Agreement or if the Parties are unable to reach definitive agreement on the terms and conditions of any extension of the Term of this Agreement prior to the fifth (5th) anniversary of the Effective Date, then the Supplier will forthwith prepare a Change Request outlining a transition plan and related Fees and Pass Through Charges associated with the termination of the Agreement on the sixth (6th) anniversary of the Effective Date.

13.2 Early Termination Events

(a) This Agreement may be terminated by either Party immediately upon notice:

(i) if the other Party commits a Material Breach of this Agreement that is confirmed as a Material Breach of this Agreement, as described in Section 13.3 (Material Breach); or

(ii) if a Triggering Event occurs in respect of the other Party; or

(iii) if the other Party assigns this Agreement (other than to an Affiliate) without the prior written consent of the terminating Party, in breach of Section 15.1 (Assignment); or

(iv) if a Change of Control occurs with respect to the other Party to which the terminating Party has not consented, provided however that the requirement for a Party to obtain the other Party's written consent hereunder shall not apply in the event the other corporation or person which is a party to the event or transaction effecting such Change of Control is an Affiliate of that Party; or

(b) Notwithstanding subsection 13.2(a) above, this Agreement may be terminated by the Supplier immediately upon notice if the Client fails to make any payment hereunder within sixty (60) days of the date the payment was due hereunder.

13.3 Material Breach

Either Party (the "**Defaulting Party**") shall be in Material Breach of this Agreement if it fails to perform any obligation hereunder which has a material adverse effect on the other Party (the "**Non-defaulting Party**"), and:

(a) such failure is not cured within thirty (30) days following notice (which for these purposes, in the case of a failure to perform a Service only, must be given within thirty (30) days after the date of performance, attempted performance or non-

performance of the applicable Service) by the Non-defaulting Party, except that (i) if such failure is not reasonably capable of being cured within such thirty (30) day cure period, but is capable of being cured, and (ii) the Defaulting Party commences promptly on notice and thereafter continues diligently to attempt to cure the failure, then such thirty (30) day cure period shall be extended until the earliest of (A) the failure has been cured, (B) the Defaulting Party ceases to diligently attempt to cure the failure, or (C) unless otherwise agreed in writing by the Parties, the expiry of a further period of thirty (30) days (for clarity, the maximum permissible cure period under this paragraph (a) is sixty (60) days subject to the agreement of the Parties otherwise);

(b) and such matter has been determined to be a Material Breach by the Panel pursuant to the dispute resolution provisions set forth in Article 14 (Dispute Resolution).

13.4 Triggering Events

Each of the following events shall constitute a "**Triggering Event**" with respect to a Party for the purposes of Section 13.2 (Early Termination Events):

(a) a receiver (unless the receivership order is vacated within thirty (30) days), trustee in bankruptcy or any other similar officer (unless such officer's appointment is vacated within thirty (30) days) is appointed to take charge of all or any substantial part of the other Party's business or property;

(b) the other Party becomes an insolvent person or commits an act of bankruptcy within the meaning of those terms in the *Bankruptcy and Insolvency Act* (Canada);

(c) a petition is filed or any other action is taken with respect to the other Party for reorganization or for arrangement under any provision of the *Bankruptcy and Insolvency Act* (Canada) or any similar Law of Canada or any province thereof then in force and providing a plan for a debtor to settle, satisfy or to extend the time for payment of debts;

(d) any application, petition, certificate or order is made or granted for the winding up or dissolution of the other Party, voluntarily or otherwise.

13.5 Effect of Termination

(a) Upon any termination of this Agreement, all applicable Change Requests shall also terminate, with the exception of any Change Request in respect of a transition plan related to termination.

(b) Upon any termination of this Agreement, the Client shall remain liable to the Supplier for all of the Fees, Additional Expenses and Pass Through Charges that are to be paid by the Client in accordance with the provisions of this Agreement, including any applicable Schedule or Change Request hereto, in respect of the

Services that are provided by the Supplier up to the date of termination. The Client shall pay to the Supplier all amounts owing hereunder, without set-off or deduction, within ten (10) days of the date of termination of this Agreement. Any such termination or payment shall not prejudice the Client's rights to audit under Article 10 (Inspections, Continuous Improvement, Audits and Security) of this Agreement or its right to recover any amounts shown thereby to have been overcharged, plus Interest as provided in Section 10.2 (Inspections and Audits).

(c) Upon early termination of this Agreement by the Supplier pursuant to Section 13.2 (Early Termination Events), or termination by the Client for any reason other than in accordance with Section 13.2 (Early Termination Events), the Client shall compensate the Supplier for any severance expenses, early termination expenses and other costs to the Supplier for reallocating resources, early termination of sub-contracts and supply arrangements and, if necessary, winding up all or part of its operations, in each case that (i) are reasonable in the circumstances, (ii) cannot be avoided with commercially reasonable efforts, and (iii) result from such termination.

(d) Upon early termination of this Agreement by the Supplier pursuant to Section 13.2 (Early Termination Events), or termination by the Client for any reason other than in accordance with Section 13.2 (Early Termination Events), the Client shall pay to the Supplier Fees for the balance of the Term of this Agreement based on the average of the Fees attributable to the Core Services plus ATCO-CIS Core Application Maintenance Fee for the three (3) months immediately preceding the earlier of (i) the early termination of the Agreement, or (ii) the date a notice or early termination of this Agreement is received, as such Fees are identified in Schedule C (Fee Schedule).

(e) Termination of this Agreement by the Supplier for any reason whatsoever shall not deprive the Supplier of any of its rights, remedies or actions against the Client. Except as expressly provided elsewhere in this Agreement, the Supplier shall be discharged from and have no further obligations or liability to the Client for Claims arising directly or indirectly following the date of termination, including for consequential losses or any other losses suffered or incurred by the Client as a result of the Supplier's termination of this Agreement, including termination of the Services. For clarity, termination of this Agreement by a Party for any reason whatsoever shall not deprive a Party of any of its rights, remedies or actions against the other Party pursuant to this Agreement in relation to Claims which have accrued prior to the date of termination.

(f) Upon any early termination of this Agreement by the Client pursuant to subsection 13.2(a)(i) or subsection 13.2(a)(ii) (Early Termination Events), Supplier shall pay the Client all commercially reasonable direct costs incurred by the Client to transfer the provision of Services back to the Client or their Third Party service provider, and, notwithstanding anything contained in Section 13.6 (Transition Plan for Termination) or Schedule F (Arbitration) to the contrary, Supplier shall be responsible for all costs incurred by either Supplier or the Client

in connection with items 1, 2, 5 and 7 of the Termination Transition Plan set out in Schedule H (Termination Transition Plan).

(g) The payment obligations of the Client under this Section 13.5 shall be cumulative.

13.6 Transition Plan for Termination

(a) Upon expiry or termination of this Agreement for any reason whatsoever, the Supplier shall, subject to the terms and conditions of this Article 13 (Term and Termination), and the limitations of the Supplier's liability set forth herein, including Article 9 (Warranties and Liabilities), provide transition services ("**Termination Transition Services**") to the Client in accordance with Schedule H (Termination Transition Plan) for a period of up to a maximum of twelve (12) months after the date of such termination, or in the case of expiry of the Agreement, during the twelve month period prior to the expiry thereof ("**Termination Transition Assistance Period**"). During the Termination Transition Assistance Period, the Client shall continue to pay all applicable Fees to the Supplier for the Services, and any additional tasks performed by the Supplier, including the Termination Transition Services, shall be charged to the Client on a Time and Materials Rate basis, or otherwise as agreed in a Change Request, including the Termination Transition Plan. The Supplier shall perform the Termination Transition Services in a timely, workmanlike, competent, conscientious and professional manner, in accordance with generally accepted standards of care in the distribution energy customer care and billing industry.

ARTICLE 14
DISPUTE RESOLUTION

14.1 Disputes

In the event of a Dispute that the Client Manager and Supplier Manager can't agree on within 5 days not subject to an exception pursuant to Section 14.3 (Exception), the following dispute resolution process will be followed:

(a) Level 1: Upon the written request of either Party, the President or Vice President of both Parties will meet for the purpose of endeavoring to resolve the Dispute or to negotiate for an adjustment to the provisions of this Agreement, including any affected Change Request. The President(s) or Vice President(s) will meet as soon as possible following either Party receiving notice of the Dispute, giving due regard to the nature and the impact of the issue under consideration, and as often as the Parties reasonably deem necessary in order to gather and furnish to the other all information with respect to the matter in issue which the Parties believe to be appropriate and germane to its resolution. The President(s) or Vice President(s) will discuss the Dispute and use commercially reasonable efforts to negotiate a resolution to the Dispute or renegotiate the applicable provision(s) of the Agreement without the necessity of any formal proceeding relating thereto. The specific format for such discussions will be determined by the President(s) or

Vice President(s) but may include the preparation of agreed upon statements of fact or written statements of position furnished to the other Party. If the Dispute is not resolved within ten (10) days following delivery of the initial written request initiating this level 1 review, or if both President(s) or Vice President(s) conclude that resolution of the Dispute through continued negotiations during this ten (10) day period is not likely to occur, then either Party may escalate the Dispute to level 2.

(b) Level 2: The person to whom the President(s) or Vice President(s) report (each a "**Chief Executive**"), for each Party shall represent such Party in a negotiation to resolve the Dispute. If the Dispute is not resolved within ten (10) days of the commencement of this level 2 review, or if both designated Chief Executives conclude that resolution of the Dispute through continued negotiations during this ten (10) day period is not likely to occur, then either Party may escalate the Dispute to arbitration pursuant to Section 14.2 (Arbitration).

14.2 Arbitration

Subject to Section 14.3 (Exception) and subject to first complying with the Dispute resolution process set out in Section 14.1 (Disputes) (or upon one (1) Party refusing or failing to so participate), any Dispute will be settled by final and binding arbitration conducted by a panel of arbitration (the "**Panel**") in accordance with Schedule F (Arbitration). Judgment upon the Award rendered in any such arbitration may be entered in any court having jurisdiction thereof, or application may be made to such court for a judicial acceptance of the Award and an enforcement order, as the Law of such jurisdiction may require or allow.

14.3 Exception

The Parties acknowledge and agree that, with respect to any Dispute arising under Article 12 (Confidentiality) or to protect an IP Right or in respect of a Claim for injunctive relief, a Party may refer such matter to arbitration in accordance with this Article 14 (Dispute Resolution) or apply to the appropriate court for relief.

14.4 Exclusive Remedy

Other than any action necessary to enforce the Award of the Panel, and subject to Section 14.3 (Exception), the Parties agree that the provisions of this Article 14 (Dispute Resolution) are a complete defense to any suit, action or other proceeding instituted in any court or before any administrative tribunal with respect to any Dispute arising under or in connection with this Agreement or any Change Request. Nothing in this Article 14 (Dispute Resolution) prevents the Parties from exercising their rights to terminate this Agreement, including any Change Request, in accordance with this Agreement or the provisions of such Change Request.

ARTICLE 15
GENERAL

15.1 Assignment

(a) Except as provided in Section 15.1(b), neither Party shall assign this Agreement, or any of its rights, benefits, warranties or obligations hereunder, in whole or in part, without the prior written consent of the other Party, provided that the other Party's consent shall not be unreasonably withheld, shall be given in a timely fashion, with no unreasonable conditions or delays.

(b) Either Party may assign this Agreement and its rights, benefits, warranties and obligations hereunder, in whole or in part, to an Affiliate, without the other Party's consent, on notice to the other Party.

(c) For the purposes of this Section 15.1, it shall be reasonable for a Party to withhold its consent, if in its opinion, acting reasonably applying reasonable, material, commercial criteria, the proposed assignee does not have the financial and other capabilities to meet prospective obligations hereunder, or if the proposed assignee is a direct competitor of the other Party in the case of the Client, in the electric distribution business in Alberta, and in the case of the Supplier, in the provision of services substantially similar to the type and scope of the present or future Services hereunder.

15.2 Non-Solicitation of Representatives

(a) Except as otherwise agreed by the Parties in writing, for the Term, any renewal term and for a period of one (1) year thereafter, neither Party will, directly or indirectly (including through a successor service provider used by the Client), recruit, hire as an independent contractor or offer employment to any Representative of the other Party who is or was substantially involved in the delivery or receipt of Services without the prior written consent of the other Party or until a period of at least twelve (12) months has elapsed after such Representative's employment with the other Party has ended.

(b) In the event of a termination of the Agreement pursuant to subsection 13.2(a)(i) or (ii) hereof, the Supplier and the Client will, as soon as reasonably possible, develop a written list of the Supplier employees that the Client would propose to offer employment to. The Parties will have five (5) Business Days from the receipt by the Supplier of the list of employees to agree whether such employees can be offered employment by the Client. If no agreement is reached within such time period either Party may submit such dispute to dispute resolution in accordance with Article 14 (Dispute Resolution). For greater certainty, all Supplier employees identified in the list of employees above shall continue in the employ of the Supplier until the dispute is resolved.

15.3 Severability

If any term or provision (other than a term or provision relating to any payment obligation) of this Agreement or the application thereof to any person or circumstances shall, to any extent, be held invalid or unenforceable, the remainder of this Agreement or the application of such term or provision to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each term and provision of this Agreement shall be valid and enforceable to the extent permitted by Applicable Law.

15.4 Independent Contractors

The Parties acknowledge that they are independent contractors and that this Agreement shall not create a relationship of employment, partnership or joint venture between the Parties or between a Party and the other Party's Representatives. Each Party specifically acknowledges that its Representatives are not employees, agents or partners of the other Party. Each Party has the sole right and obligation to supervise, manage, contract, direct, procure, perform or cause to be performed all work to be performed by that Party under this Agreement. Nothing in this Agreement shall restrict or preclude the Supplier from performing customer care and/or billing services from time to time for the Supplier's other present or future clients.

15.5 Governing Law

This Agreement and any Disputes arising or resulting from the transactions contemplated under this Agreement shall be exclusively construed and governed in all respects by the Laws of the Province of Alberta and of Canada applicable therein. The Parties submit to the exclusive jurisdiction of the courts of Alberta for any Dispute not submitted to arbitration pursuant to this Agreement.

15.6 Survival

Notwithstanding the termination of this Agreement for any reason, any obligations which by their nature are intended to survive such termination shall continue in full force and effect until discharge of the obligation or until the Parties mutually agree to a release of such obligation, which obligations shall include any obligations dealing with Fees, Pass Through Charges, Additional Expenses and any other payments, warranties, indemnities and liabilities (Article 9 Warranties and Liabilities), records and inspections (Section 10.1 and Section 10.2(b)), ownership (Article 11 Ownership), confidentiality (Article 12 Confidentiality), dispute resolution (Article 14 Dispute Resolution), non-solicitation of Representatives (Section 15.2 Non-Solicitation of Representatives) and governing law (Section 15.5 Governing Law).

15.7 Entire Agreement

This Agreement constitutes the entire agreement between the Parties hereto pertaining to the subject matter of this Agreement and supersedes all prior and contemporaneous agreements, understandings, representations, negotiations and discussions, whether oral or written, including letters of intent or other agreements of the Parties hereto including the MSA, and there are no warranties, representations or other agreements between the Parties hereto, implied or express, statutory or otherwise, in connection with the subject matter hereof except as specifically set

forth herein. For further clarification, the Client acknowledges and agrees that it is not relying upon any representation in any advertising, marketing material, catalogues, background materials, volume estimates, proposals or similar materials provided or distributed by the Supplier. This Agreement may not be amended, modified or superseded unless expressly agreed to in writing by both Parties. Any Schedule(s), Change Request(s) or may contain additional terms and provisions applicable to this Agreement. In no case shall the pre-printed terms and conditions on the Client's purchase order or other standard transactional documentation modify the Agreement or otherwise apply to the Supplier.

15.8 Consent to Breach not Waiver

The observance of any Term of this Agreement may be waived (either generally or in a particular instance and either retroactively or prospectively) by the Party entitled to enforce such term, but such waiver shall be effective only if it is in writing and signed by the Party against whom such waiver is to be asserted. Unless otherwise expressly provided in this Agreement, no delay or omission on the part of any Party in exercising any right or privilege under this Agreement shall operate as a waiver thereof, nor shall any waiver on the part of any Party of any right or privilege under this Agreement operate as a waiver of any other right or privilege under this Agreement nor shall any single or partial exercise of any right or privilege preclude any other or further exercise thereof or the exercise of any other right or privilege under this Agreement.

15.9 Notices

(a) Any notice, document or other communication required or permitted to be given hereunder shall be in writing and shall be sufficiently given if sent by prepaid mail, if delivered personally, or if sent by facsimile transmission, to the following addresses:

(i) To the Supplier:

ATCO I-Tek Business Services Ltd.
10035-105 Street
Edmonton, Alberta T5J 2G5

Attention: Account Manager, Distribution
Facsimile: (780) 420-7746

(ii) To the Client:

ATCO Electric Ltd.
Customer Care & Billing Governance
10035-105 Street
Edmonton, Alberta T5J 2G5

Attention: Manager, Customer Care & Billing Governance
Facsimile: (780) 420-8984

(b) Any such notice shall be deemed to have been given:

(i) if mailed, on the fifth (5th) Business Day following such mailing, provided that in the event of a disruption in postal service any notice so mailed shall be deemed to have been delivered on the fifth (5th) Business Day following the resumption of regular postal service;

(ii) if delivered personally, on the Business Day delivered, or if the day of delivery is not a Business Day, then on the next Business Day following such delivery;

(iii) if sent by facsimile transmission, if delivered prior to 4:00 p.m. on a Business Day then on that Business Day, otherwise on the first Business Day following such delivery or transmission, provided that the sending Party receives verification from the facsimile machine used to send the notice that the complete facsimile was transmitted without error. Any notice sent by facsimile transmission shall be followed with a copy sent by prepaid mail within one (1) Business Day of such transmission.

(c) Each of the Parties hereto shall be entitled to specify a different address by giving notice in accordance with the terms hereof.

(d) Any notice, document or other communication relating to a Schedule may be sent to the person or address designated in such Schedule.

15.10 Successors and Assigns

This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns, if any, of the Parties hereto, except that nothing contained in this clause shall be construed to permit any attempted assignment which would be unauthorized or void pursuant to any other provision of this Agreement.

15.11 Further Assurances

The Parties agree to do or cause to be done all such further acts or things required to implement and carry into effect this Agreement to its full extent.

15.12 Currency

Unless indicated otherwise in a particular Schedule, invoice or Change Request, all amounts referred to herein are stated and shall be payable in Canadian funds.

15.13 Force Majeure

Except with respect to payment obligations hereunder, neither Party hereto shall be liable to the other Party or considered to be in default under this Agreement for any delay or failure to perform its obligations hereunder due to strikes, labour disputes, riots, terrorism, explosions, earthquakes, acts of God, pandemic, severe weather conditions materially preventing or

impairing work, failure or fluctuations in electrical power, heat, light, air conditioning, telecommunications equipment or lines, acts of any Governmental Authority, war, failure or delay of any Third Party supplier, unavailability or shortages of materials, equipment failures or any other cause or causes which are beyond the reasonable control of such Party and which could not have been reasonably foreseen and provided against. A Party seeking relief from its obligations pursuant to this Section shall promptly give notice of the event giving rise to its claim to relief and use commercially reasonable efforts to avoid or, if unavoidable, minimize the effects of any such event upon the performance of their respective obligations under this Agreement, including through the operation of their respective business continuity plans then in effect.

15.14 Timely Performance

Unless otherwise specified, references to time of day or date mean the local time or date in the City of Edmonton, Alberta. Time is of the essence in the performance by the Parties of their respective obligations hereunder.

15.15 Remedies Cumulative

Unless stated otherwise herein, all remedies provided for in this Agreement shall be cumulative and in addition to and not in lieu of any other remedies available to either Party at Law, in equity or otherwise. No single or partial exercise by a Party of any right or remedy precludes or otherwise affects the exercise of any other right or remedy to which that Party may be entitled.

15.16 Understanding

Each of the Parties acknowledges that it has read and understood this Agreement and agrees to be bound by its provisions.

15.17 Facsimile; Counterparts

This Agreement, and any document contemplated under this Agreement, may be executed in any number of counterparts which may be exchanged by facsimile, each of which shall be deemed an original and all of which together shall constitute one and the same Agreement.

15.18 Inter-Affiliate Code of Conduct

Each of the Parties hereto represents and warrants to the other that this Agreement, as amended hereby, complies with the ATCO Group Inter-Affiliate Code of Conduct (EUB Decision 2003-040).

IN WITNESS WHEREOF the Parties have executed this Agreement effective as of the date first above written.

ATCO I-TEK BUSINESS SERVICES LTD.

Per: _____
Name:
Title:
Date Executed:

Per: _____
Name:
Title:
Date Executed:

ATCO ELECTRIC LTD.

Per: _____
Name:
Title:
Date Executed:

Per: _____
Name:
Title:
Date Executed:

CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Effective January 1, 2010

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Definition of Services

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Appendix A: Client Deliverables
Appendix B: Standard Reports

1. Introduction

This is Schedule A to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. (the "**Supplier**") and ATCO Electric Ltd (the "**Client**").

1.1. Scope

This Schedule describes the Services provided by the Supplier to the Client pursuant to the Agreement. It is not a comprehensive list of all business policies or detailed procedures.

The Services described herein are directly related to the Client's provision of electric distribution service and meter data management to its Customers.

Section 1 contains the following information:

- definitions used in this Schedule.
- a description of how this Schedule is organized.
- assumptions upon which the Services are based.
- an brief summary of how the Client, Retailers, Customers and the Supplier will interact regarding the Services.

1.2. Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Additional Responsible Parties**" or "**ARP**" means Persons who share financial responsibility for a Statement Account in accordance with the Service Policies (e.g. a roommate, spouse, guardian or guarantor);

"**Agent**" means a company authorized by a Retailer or Distributor Site Customer, as the case may be, to act on its behalf, including to manage their day to day affairs with the Client;

"**Automated Meter Reading**" or "**AMR**" means the process by which the Client obtains meter reading automatically and electronically sends them to ATCO-CIS;

"**AUC**" or "**Commission**" means the Alberta Utilities Commission;

"**CAC Regular Hours of Operation**" means the hours between 7:00 a.m. and 7:00 p.m. on Business Days;

"**Company Use Accounts**" means Service Accounts set up for the Client for their own use (e.g., for the Client to operate a substation or other Client facility);

"**CONP**" means cut off for non payment;

"**Customer**" means Retailers, Site Customers, Site Owners, Site Contacts and Additional Responsible Parties;

"**Customer Assistance Centre**" or "**CAC**" means the Supplier's call centre. The CAC handles account and distribution service related inquiries as described herein;

"**Daily Cumulative Meter**" or "**DCM**" has the meaning described in the SSC;

"**De-Enrollment**" means the process of removing a Retailer from providing energy to a Site;

"**Distribution Charges**" or "**Distribution Tariff**" or "**D-Tariff**" means the charges from the Client to the Retailer or Distributor Site Customer for the distribution and transmission of electricity to a Site;

"**Distributor**" has the meaning given in the *Gas Utilities Act* (Alberta) in respect of the gas distribution business, and the meaning given in the *Electric Utilities Act* (Alberta) in respect of the electricity distribution business, as the case may be;

"**Distributor Support Services**" means the Supplier's workgroup that coordinates electronic communications with Retailers (e.g., Tariff Bills, E-bills, Enrollments, etc.);

"**DropChute™**" means an Internet based tool used to exchange data electronically with Distributors and Retailers as required by Applicable Law in Alberta;

"**Enrollment**" means the assignment of a Site to a Retailer for the provisioning of energy by the Retailer and load settlement by the Load Settlement Agent;

"**Field Order**" means a request, typically initiated in ATCO-CIS that generates a request for field work in the Client's Work Management System(s);

"**Historical Usage File**" or "**HUF**" means the electronic transactions used to support "Standards for Requesting and Exchanging Site-Specific Historic Usage Information for Retail Electricity and Natural Gas Markets Rules";

"**Idle Service**" means a service that has been temporarily de-energized with the intent of being re-energized at a later date;

"**Idle Sites**" means a Site that is not energized but does not have charges payable to the Client;

"**Independent System Operator**" or "**ISO**" has the meaning given in Section 7 of the *Electric Utilities Act* (Alberta);

"**Isolated Site**" means a Site for which the Client provides wires and energy related products and services which is not connected to the province-wide electricity supply grid and is not eligible for retail electricity services;

"**Load Settlement Agent**" or "**LSA**" means the party conducting load settlement calculations for a particular settlement zone;

"**Mass**" will apply when the Client submits a request for service that either increases the volume of work from normal volumes or requests the services be

completed on a timeline that causes the Supplier to add additional resources to comply with the request;

"**Policy Manual**" the Supplier will use the Service Policies to deliver Services to the Client. The Service Policies will be owned by the Client and maintained by the Supplier. The Supplier and the Client each have responsibility to identify when changes to policies are warranted, with all changes subject to the approval of the Client;

"**Power Pool**" means an electric energy exchange in Alberta that is an independent, central, open-access pool that functions as a spot market, matching demand with the lowest supply to establish an hourly pool price;

"**Pre-authorized Payment Plan**" or "**PPP**" means a payment plan that allows Distributor Site Customers to have funds automatically withdrawn from their bank account to pay their bills;

"**REAL**" means Rural Electrification Association Limited;

"**Retailer Guide**" means a handbook of procedures, forms and other information used by Retailers to conduct their business with the Client, acting through the Supplier;

"**Service Account**" means an account set up for the purposes of calculating charges for a service for a specified period of time;

"**Service Category**" has the meaning described in Section 1.3.1 (Service Categories) of this Schedule;

"**Settlement System Code**" or "**SSC**" means the information sharing standards established by the Independent System Operator pursuant to the *Electric Utilities Act*, S.A. 2003, c. E-5.1, as amended from time to time;

"**Site ID**" means the unique thirteen (13) digits assigned to a Site and is the key element for sharing information between Retailers, Distributors, Load Settlement Agents, Site Customers and other parties;

"**Statement Account**" means an account assignment to a Customer or Retailer which brings together financial transactions for one or more Service Accounts, (e.g. charges, payments, and late pay fees);

"**Tariff Bill Code**" or "**TBC**" means the rule that set out the minimum obligations of a Distributor under the supervision of the AUC to provide timely and accurate tariff bill-ready information to Retailers for distribution and system access service provided by the Distributor to the Retailer;

"**Tariff Bill File**" or "**TBF**" means a physical electronic file containing Site-specific tariff charges, usage, and demand information for given tariff bill periods; it may also contain applicable Site-specific one-time charges;

"**Terms and Conditions for Distribution Access Service**" means the terms and conditions that outline the rules that Retailers and Agents must follow to engage in Retailer transactions with the Client;

"**Terms and Conditions for Distribution Service Connections**" means the terms and conditions that serve as a companion to the Terms and Conditions for Distribution Access Service, which is intended to enable Retailers to acquire access to the Client's electric distribution system for the purposes of allowing them to sell electricity directly to end-use Customers;

"**Update Customer Information**" or "**UCI**" means the electronic transaction used by Retailers in accordance with the SSC to send Customer information such as the Site Contact, the financially responsible party, their phone number and billing address, to the Distributor;

"**Work Management System**" means the Client system that receives, packages, initiates and completes work requests;

"**Work Request**" means the request generated by the Client's Work Management System for field work; and

"**Work Queue**" means an ATCO-CIS feature used to manage items that need review and approval, for example, refund requests, adjustments, high or low usage, or too many consecutive estimates.

1.3. How this Schedule is Organized

1.3.1 Service Categories

The Services are described in this Schedule under the following Service categories (the "Service Categories", each being a "Service Category"):

- **Relationship Management:** How the Supplier interacts with Retailers, Site Customers and Site Contacts, including the mode of communication.
- **Account Management:** The Services the Supplier provides to manage the Clients' accounts with Retailers and Distributor Site Customers.
- **Revenue Management:** The Services the Supplier provides to manage meter reads, usage, charges and adjustments, including calculations, quality assurance and how the Supplier provides this information to Retailers, Site Customers and Site Contacts.
- **Equipment Information Management:** The Services the Supplier provides related to meters and other equipment.
- **Receivables Management:** The Services the Supplier provides to manage payments, credit adjustments and credit-related activities for the Clients' accounts receivable.
- **Financial Management:** The Services the Supplier provides for balances and controls of internal accounts and Services, financial reporting and other Services related to the Client's third party accounts.
- **Consulting and Special Services:** Optional Services the Supplier can provide to the Client.
- **Administration:** The processes for how the Supplier and the Client work together.

1.3.2 Core vs. Optional Services

This Schedule describes the Core Services to be provided by the Supplier under this Agreement as well as optional Services that can be provided by the Supplier pursuant to a Change Request.

Pricing for the Services is specified in Schedule C (Fee Schedule) of the Agreement.

Optional Services are designated as **"(optional)"** throughout this Schedule. Pricing for optional Services is either specified in Schedule C (Fee Schedule) of the Agreement, or will be defined by the Client and the Supplier pursuant to the applicable Change Request.

With the exception of Core Services, prices defined in Schedule C (Fee Schedule) are noted throughout this Schedule as indicated below. Fee schedules are listed **only** for those services that are not covered under the Core Services Fee e.g. Statement of Work, Pass-Through Charges.

Fee Schedule: Statement of Work (Optional Service)

Pass-Through Charges

1.3.3 Statements of Work

During the Term of the Agreement, the Client may request or the Supplier may recommend that the Supplier undertake a specific project which may result in additional Services being performed by the Supplier or will result in the provisions of the Services being changed, modified or enhanced.

Upon the Supplier receiving such a request from the Client, the Supplier will prepare a Statement of Work in accordance with the procedures and requirements outlined in Article 4 (Changes in Service and Projects) of the Agreement.

For greater certainty, a Statement of Work will be prepared for projects that have a clearly defined start and end date, but may change, modify or enhance the Supplier's Services provided to the Client after the project is completed. If at the completion of the project the Services provided to the Client are changed, modified or enhanced, the Statement of Work will govern the service.

In the event that a change is requested to a Service that is provided to the Client that has an outstanding Statement of Work a Change Addendum will be provided by the Supplier.

1.3.4 Change of Service Requests

During the term of the Agreement, the Client or the Supplier may seek a change, modification or enhancement to the Services. In such cases, the Supplier will prepare a Change of Service Request in accordance with the procedures and requirements outlined in Article 4 (Changes in Service and Projects) of the Agreement.

1.3.5 Policy Manual

The Supplier will use the Service Policies to deliver Services to the Client. The Service Policies will be owned by the Client and maintained by the Supplier. The Supplier and the Client each have responsibility to identify when changes to policies are warranted, with all changes subject to the approval of the Client.

1.3.6 Client Deliverables

Some billing policies and processes are Client driven, e.g., number of days before late pay fees become payable by a Customer, late pay fee percentage and credit policies. Processes and policies that require Client direction and input are identified throughout this Schedule with a table similar to the table below:

Client to Provide...	Format	Timing
Description of deliverable	Expected format	When required

1.4. Assumptions

The Services described herein are based on the following assumptions:

- The Client provides wires-related products and services and does not sell energy to any Sites. If a Site is connected, the Client bills the Retailer for distribution charges. The Retailer charges the Retailer Site Customer for distribution charges.
- All connected Sites other than Distributor Site Customers' Sites must be Enrolled with a Retailer on a competitive retail plan, the regulated rate tariff, or the Default Supplier.
- The Client only bills Distributor Site Customers (other than Isolated Sites) directly when a Site is not connected and not Enrolled with a Retailer, or for miscellaneous charges that are billed directly to the Distributor Site Customer.
- The Client bills Isolated Sites directly for both Distribution Charges and energy charges, where applicable.
- The Client is responsible for ensuring the quality of meter reads and usage, including investigating items flagged by the Supplier for review. The Supplier is responsible for billing adjustments required as a result of changes to meter reads and usage data provided by the Client.
- The Supplier will create ATCO-CIS Field Orders to initiate investigations in a manner consistent with the Client's current practices. This makes the Supplier aware of the activity when dealing with inquiries or internal quality assurance processes.
- The Services described herein are based on the current and approved Client Terms and Conditions for Distribution Access Service, Terms and Conditions for Distribution Service Connections and the requirements of Applicable Law in effect as of January 1, 2010.

1.5. Role of Client, the Supplier, Retailers and Site Customers

Communication among the Supplier, the Client, Retailers and Site Customers in connection with the Services is set forth in this Schedule and the applicable Service Policies.

The Supplier is the initial point of contact for inquiries made by Retailers, Site Customers, Site Contacts and ARP's.

The Supplier will re-direct Site Customers to the Client when the inquiry relates to a request for new distribution service lines and distribution service alterations.

The Supplier will re-direct Retailer Site Customers to their Retailer when the inquiry is related to Retail billing or account management issues.

The Client is responsible for notifying the Supplier of all distribution business activities that may require Retailer, Site Customer, Site Contact and/or ARP communications to be initiated or that may impact upon inbound call center activity.

An example of how these activities are coordinated is set forth below:

Client to Provide...	Format	Timing
Policy on communications between the Supplier, Retailer, Site Customers and Site Contacts. D2-100	MS-Word	
Policy on acceptable forms for making inquiries. D2-110		
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		
Policy on handling customer account inquiries. D2-145		

Example: *The Supplier coordinates work between the Client and the Retailer or Retailer Site Customer.*

The Client is responsible for keeping the Supplier informed of all Change in Law, including changes in information systems, business processes, data standards and other similar items mandated by the Alberta Government or any other Governmental Authority that may affect the Services described herein. The Client must provide the Supplier with sufficient notice to permit the Supplier to evaluate and implement the requested change on or before the required date.

When the Client requests such changes, the Supplier will assess the impact upon the Services, and determine if a Change Request is required. The Supplier will coordinate the testing and implementation of these changes with the Retailer, Distributor, Load Settlement Agent and other affected parties.

When the Supplier is contacted regarding matters not within their scope of Services, the Supplier will refer the caller to the appropriate Retailer or Governmental Authority as required by Applicable Law.

2. Relationship Management

This Section outlines how the Supplier will manage the relationship with Retailers, Distributor Site Customers, Retailer Site Customers and Site Contacts for the Client.

The Supplier will interact with Retailers, including Self-Retailers and Agents, in a manner consistent with Service Policies.

The Supplier will interact with Site Customers, Site Contacts and ARP's in a manner consistent with Service Policies, using Client-approved scripts and training materials unique to the Client's business where appropriate.

The nature of the Supplier's interactions and modes of communication with Retailers, Site Customers, Site Contracts and ARP's are described in further detail below.

Client to Provide...	Format	Timing
Policy that specifies the type of communications the Supplier will have with Retailers, Distributor, Site Customers, Retailer Site Customers, Site Contacts and ARP's. D2-100	MS-Word	

2.1. Inbound Contacts

This Section identifies how the Supplier will handle inquiries and requests from Retailers, Site Customers, Site Contacts and ARP's. Refer to Appendix A (Client Deliverables) for a summary table.

Client to Provide...	Format	Timing
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		

Retailer Inquiries

The Supplier will handle the following inquiries from Retailers including but not limited to:

- Site Enrollment and De-Enrollment status.
- Site ID inquiries.
- SSC, TBC, HUF transactions.
- Usage-related issues.
- Statement Account billing inquiries, e.g., interpreting Tariff Bill Files, comparing gross billing amounts of current and past statements, etc.
- Deregulation related matters, e.g. rebates, options available, etc.
- Price inquiries related to the Distribution Tariff and other fees charged by the Client.
- General billing and high bill inquiries.

Client to Provide...	Format	Timing
Policy that specifies the type of communications the Supplier will have with Retailers, Site Customers, Site Contacts and ARP's. D2-100	MS-Word	
Policy defining acceptable forms and methods for making requests. D2-110		
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		

Retailer Site Customer Inquiries

The Supplier will advise Retailer Site Customers to contact their Retailer for billing-related matters, e.g., high bill complaints or wrong energy price Schedule.

The Supplier will handle inquiries for deregulation-related matters, e.g., Site ID or general options available with deregulation.

The Supplier will handle facility-related inquiries from Retailer Site Customers in accordance with the Service Policies including:

- Price inquiries related to the Distribution Tariff (not including miscellaneous fees).
- Emergency and outage.
- Meter reads.
- Facility related inquiries, e.g., meter moves, meter upgrades.
- Distribution service quality complaints.

Client to Provide...	Format	Timing
Policy that specifies the type of communications the Supplier will have with Retailers, Site Customers, Site Contacts and ARP's. D2-100	MS-Word	
Policy on managing inbound calls relating to the Motorist Observation Program(MOP). D2-105		
Policy defining acceptable forms and methods for making requests. D2-110		
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		

Distributor Site Customer Inquiries

The Supplier will handle billing and Site related inquiries from Distributor Site Customers in accordance with the Service Policies including:

- Customer Service (distribution service requests).

- Meter Reading.
- General Inquiries (including but not limited to price inquiries, deregulation, deposit requirements, and distribution service quality inquiries).
- Emergency and outage.
- Providing a history of meter reads and usage.
- Customer provided meter reads.
- Updating Site Customer / Contact / Owner information, e.g., name and phone.
- Site energizes, de-energizes, safety or seasonal de-energizes and special meter read requests.
- Meter equipment changes.
- Account balance, general billing and high bill inquiries.
- Missing or misapplied payments.
- Explanation of credit letters, notices, etc.
- Facility-related inquiries.

Client to Provide...	Format	Timing
Policy that specifies the type of communications the Supplier will have with Retailers, Site Customers, Site Contacts and ARP's. D2-100 Policy defining acceptable forms and methods for making requests. D2-110 Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115	MS-Word	

Site Contact and ARP Inquiries

The Supplier will handle Site Contact and ARP inquiries in accordance with the Service Policies, e.g., handle calls and provide information to the Client or advise the Site Contact or ARP to contact the Client directly.

Client to Provide...	Format	Timing
Policy that specifies the type of communications the Supplier will have with Retailers, Site Customers, Site Contacts and ARP's. D2-100 Policy defining acceptable forms and methods for making requests. D2-110 Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115	MS-Word	

Retailer Requests

The Supplier will receive and process requests from retailers in accordance with the Settlement System Code, the Tariff Billing Code and HUF (Rule 010 – Historic Usage Procedures) including but not limited to

- Site Enrollments and De-Enrollments.
- Updating Retailer Site Customer (including Site Contact) information.
- Site connections, disconnections, safety or seasonal disconnects and special meter read requests.

The Supplier can receive Site-related requests and coordinate with the Client in accordance with Service Policies including:

- Providing standard usage reports as specified by the Client.
- Routine Site inspections.
- Metering changes.

Client to Provide...	Format	Timing
Policy that specifies the type of field orders that can be issued by the Supplier. D2-380	MS-Word	

The Supplier can apply special charges to Retailers for their requests at the direction of the Client.

Client to Provide...	Format	Timing
Policy defining when service fees are charged and/or waived. D2-510	MS-Word	

Retailer Site Customer Requests

The Supplier can handle billing related requests in accordance with the Service Policies including:

- Providing a history of meter reads and usage.
- Site Contact provided meter reads.
- Updating Site Customer / Contact / Owner information, e.g., name and phone.

The Supplier can receive facility related requests and coordinate with the Client in accordance with the Service Policies including:

- Site connections, disconnections, safety or seasonal disconnects.
- special meter read requests.
- Metering changes.

Client to Provide...	Format	Timing
Policy that specifies how the Supplier will manage customer inquiries. D2-100	MS-Word	
Policy defining acceptable forms and methods for making requests. D2-110		
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		
Policy defining the conditions required when Field Orders are requested by the Supplier. D2-325		
Policy on how the Supplier will manage Retailer requests to cancel a de-energize order D2-327		

Distributor Site Customer Requests

The Supplier will handle billing related requests including:

- Providing a history of meter reads and usage.
- Customer provided meter reads.
- Updating Site Contact information, e.g., name and phone.

The Supplier can receive facility related requests and coordinate with the Client in accordance with the Service Policies including:

- Site connections, disconnections, safety or seasonal disconnects.
- Special meter read requests.
- Metering changes.

Client to Provide...	Format	Timing
Policy that specifies how the Supplier will manage customer inquiries. D2-100	MS-Word	
Policy defining acceptable forms and methods for making requests. D2-110		
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		
Policy defining the conditions required when Field Orders are requested by the Suppliers. D2-325		
Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327		

2.2. Inbound Contact Methods

This Section describes how the Supplier will handle inbound contact from the Client, Retailers, Site Customers, Site Contacts, Site Owner, and ARP's.

Phone

The Supplier's Customer Assistance Centre (CAC) will handle inbound inquiries from Retailers, Site Customers, Site Contacts, Site Owner, ARP's and others (collectively "Callers").

The Supplier uses an auto-attendant feature that allows Callers to select specific call queues.

The Supplier will record, store, and provide Client access to all recorded calls to the CAC for reference in accordance with the terms of the Agreement, including Sections 10.3 (Continuous Improvement) and 10.5 (Charges) thereof. All recordings are retained for a three (3) month period. Individual calls may be retained for longer periods at the request of the Client or at the Discretion of the Supplier.

The Supplier will provide the Client with access to individual recordings with twenty four (24) hours notice from the Client, subject to having sufficient information to locate the call, i.e., date and approximate time. The Supplier will also provide the Client with more immediate access to individual recordings as requested, for calls that are involved in escalated or emergency situations or issues, provided there is sufficient information to locate the recording.

Full Interactive Voice Response system/Voice Recognition Unit capability is available **(optional).**

Fee Schedule: Statement of Work

The Supplier can retain recordings for a period greater than three (3) months. **(optional)**

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Policy that specifies the type of requests the Supplier will accept by phone. D2-110 Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115 Policy that defines how the auto-attendant feature is used. D2-120 Policy on redirecting emergency calls. D2-142	MS-Word	

Written Correspondence

The Client, Retailers, Site Customers, Site Contacts, Site Owner, and ARP's can contact the Supplier by fax, regular mail or courier.

Client to Provide...	Format	Timing
Policy that specifies the type of requests the Supplier will accept by written correspondence. D2-110 Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115	MS-Word	

Returned Mail

The Supplier will handle mail returned due to incorrect addressing, changes in residency, etc. and follow up as per Service Policies.

Client to Provide...	Format	Timing
Policy that defines how the Supplier will manage returned mail. D2-160	MS-Word	

E-Mail

The Client, Retailers, Site Customers, Site Contacts, Site Owner, and ARP's can contact the Supplier by e-mail.

Client to Provide...	Format	Timing
Policy that specifies the type of requests the Supplier will accept by e-mail. D2-110	MS-Word	
Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115		

The Supplier can also create and manage e-mail addresses specified by the Client.

Fee Schedule: Pass-Through Charges (Domain registration, hosting, etc.)

DropChute™

DropChute™ is an Internet based tool used to exchange data electronically with Distributors and Retailers as required by regulations in Alberta.

The Supplier will accept and respond to requests, and exchange information with Retailers, Self-Retailers, and Agents using industry standard **DropChute™** transactions in accordance with Service Policies and the Client's Terms and Conditions for Distribution Access Service. Examples of these transactions include, but are not limited to, the following:

- Field Orders (energize, de-energize, meter reads).
- Enrollments.
- De-Enrollments.
- Update Customer Information.
- Site Usage Information.
- Load Settlement Information.

Client to Provide...	Format	Timing
Policy defining the conditions that must exists for the Supplier to initiate Field Orders for connections, reconnections and disconnections. D2-325		
Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327		
Policy defining when it is acceptable for the Supplier to accept a Customer provided meter reading. D2-450		
Policy defining when the Supplier can request an 'off-cycle' meter reading. D2-460		
Policy defining the Client's responsibility for confirmation of site enrollment by Retailers. D2-295		
Policy defining when the Supplier is to follow up on enrollment requests. D2-300		
Policy identifying when the Client's requirements for processing Retailer site de-enrollments. D2-310		
Policy specifying financial responsibility for site. D2-322		
Policy on updating Site Customer information. D2-260		
Policies on how the Supplier will manage site usage information requests. D2-100 and D2-523		
Policy relating to validating and managing load settlement and Daily Cumulative Meter data. D2-664		

Communication Log

The Supplier will record all inbound CAC communications in a communication log for communications related to Sites in the Client's service area.

Client to Provide...	Format	Timing
Policy that specifies the type of communications with Site Customers, Site Contacts, ARP's or Retailers relating to Services the Supplier provides. D2-100	MS-Word	
Policy that specifies when communication records should be recorded, e.g., for billing disputes, accounts over $**x**, etc. D2-150		

2.3. Outbound Contacts

This Section describes how the Supplier will communicate with the Client's Customers where the Client initiates the contact.

Bill Messaging

The Supplier will use ATCO-CIS to include messages on paper bills sent to Distributor Site Customers.

Client to Provide...	Format	Timing
Policy outlines responsibilities of the Client and the Supplier related to bill messaging. D2-275	The Supplier to Provide Form	

Messaging Options

The Supplier provides three types of bill messages:

1 – Pre-defined, system-generated messages used when pre-defined conditions occur, e.g., missed payment, thank you for your payment.

2 –Client-defined messages using pre-defined selection criteria, e.g., advising of price changes or a payment plan promotion to relevant accounts.

3 –Client-customized messages with Client-customized selection criteria **(optional)**.

Pre-Defined Selection Criteria (Includes options 1 & 2 above)

The pre-defined selection criteria cover most common messaging situations. Criteria that can be used separately or in combination[1] includes but is not limited to:

- Service Account Use Class, e.g., residential, commercial or industrial.
- Price Schedule.
- District, community or municipality.
- Credit rating.
- Last payment source.
- Last statement amount and/or overdue amount ranges.
- Postal code.
- Pre-authorized payment accounts.

[1] A complete list of criteria and allowable combinations will be provided in the Service Policies. The above list of criteria is for example only.

Custom Selection Criteria (Optional)

The Supplier can work with the Client to define custom selection criteria when the pre-defined criteria are not appropriate. After reviewing the Client's specific requirements, the Supplier will provide a variety of options.

The time and effort required to define custom selection criteria depends on the complexity of the criteria. Sufficient advance notice from the Client is required for system programming and testing by the Supplier.

Fee Schedule: Change of Service Request

Note: This item allows you to totally customize the messaging to be different from current practices. Our system is built to accommodate many selection criteria, but this item covers situations where you request a selection method that we do not currently have in place.

Client to Provide...	Format	Timing
Bill message text and selection criteria.	The Supplier to Provide Form	At least five working days for message text. Number of days required for new criteria varies with complexity
Policy outlines responsibilities of the Client and the Supplier related to bill messaging. D2-275	The Supplier to Provide Form	

Customer Letters

The Supplier will send credit-related letters to Site Customers based on the Service Policies, e.g. credit rating, amount in arrears, number of days in arrears, etc.

The Supplier will notify Site Customers by letter of changing security requirements in accordance with the Service Policies.

The Supplier will also send manually created letters to respond to specific matters in accordance with the Service Policies.

Fee Schedule: Additional Services, Letter Printing
Pass-Through Charges (Letterhead, envelopes, etc.)

Client to Provide...	Format	Timing
Approval of form letters and criteria for mailing.	MS-Word-	Before Service commences

Fax and E-Mail

The Supplier will send faxes and e-mail to persons authorized to receive the information. The Supplier will only release information to the Client's Customers if the Supplier has received prior written authorization in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy for releasing information to authorized third parties. D2-180	MS-Word-	

DropChute™ (Retailers only)

The Supplier will send information to Retailers using DropChute™ as required by the Settlement System Code.

2.4. Standard Languages

Verbal Services

The Supplier will provide verbal Services in English only.

The Supplier can provide verbal Services in French or other languages **(optional)**.

Fee Schedule: Change of Service Request

Written Services

The Supplier will provide written Services, e.g., letters, bills or bill inserts, to Customers in English only.

The Supplier can provide written Services, e.g., letters, bills or bill inserts, to Customers in French or other languages **(optional)**.

Fee Schedule: Change of Service Request

2.5. Special Needs

Hearing Impaired Services

The Supplier will provide the following options for serving hearing impaired.

- E-mail,
- Fax.

The Supplier can also provide a TDD (Telephone Device for the Deaf) Service.

Translation Services

The Supplier can also access external translation Services for many languages.

Fee Schedule: Pass-Through Charges

2.6. Release of Information

The Supplier will comply with the Service Policies governing privacy and access to information, as required.

The Supplier will discuss account and meter read information with only the person or company with financial responsibility or those who have been authorized to receive the information. In other situations, the caller is advised that the information cannot be provided without consent.

The Supplier will discuss reads and usage with the Retailer Site Customer on record in accordance with the Service Policies.

Retailers and Site Customers can authorize the Supplier to discuss their accounts with a specific person in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on the release of information to Retailers, Site Customers, Site Contacts and ARP's e.g., when written or verbal authorization is required. D2-180	MS-Word-	

2.7. Working with Retailers

This Section describes how the Supplier will manage Retailers for the Client, including:

- Retailer Qualification.
- Retailer Setup and Compliance Testing.
- Ongoing Monitoring of Retailer Transactions.
- Retailer Business Processes.
- Communicating with Retailers and Their Agents.
- Retailer/Customer Issue Management.

Retailer Qualification

The Client will establish the criteria and processes for Retailer qualification. The Client is also responsible for approving or disqualifying Retailers based in part on information obtained by the Supplier from the Retailer and as reported by the Supplier based on the Retailer's performance.

The Client will provide the Supplier with its Terms and Conditions for Distribution Access Service.

Client to Provide...	Format	Timing
Retailer qualification under Terms and Conditions for Distribution Access Service.	MS-Word-	Before Service Commences

Retailer Setup and Compliance Testing

The Supplier will setup the required systems, processes, accounts and other requirements when the Client notifies the Supplier that a new Retailer has qualified for distribution access.

The Supplier will work with Retailers to test electronic transactions sent to the Supplier with DropChute™. Before a Retailer can serve Retailer Site Customers and conduct key transactions, a Retailer must demonstrate that it can communicate electronically with the Supplier as specified in the Settlement System Code, the Supplier's technical standards and the Client's Terms and Conditions for Distribution Access Service.

Fee Schedule: Statement of Work

Ongoing Monitoring of Retailers Transactions

The Supplier will monitor and report the Retailers adherence to their obligations under the Terms and Conditions for Distribution Access Service and its Retail

Service Agreement and on other Retailer activities regarding the following matters:

- Quality of Retailer transactions, e.g., Enrollment success rate.
- When significant disputes arise about account-related activities, e.g., disputed bills.
- Enrollments or De-Enrollments that cannot be easily resolved. These disputes do not include normal investigation and resolution of account activities.

Client to Provide...	Format	Timing
Policy on what the Supplier will monitor and the reports the Supplier will produce D2-630	Expected format	When required

Retailer Business Processes

The Supplier will provide ongoing consulting Services to the Client to maintain the handbook for Retailers and to help achieve efficiencies and work with the Client to streamline the business processes for dealing with Retailers.

Client to Provide...	Format	Timing
The Supplier with detailed business processes that document how the Supplier, the Client and Retailers will work together.		
Specific requirements for the Retailer Guide, e.g., electronic versus print format, specific items to be included, etc.	MS-Word-	Before Service Commences

Communicating with Retailers and Their Agents

The Supplier will communicate with Retailers in accordance with the guidelines established in the Settlement System Code and as defined by the Client.

The Supplier will provide Retailers with the Client's standards for transactions that can be sent by DropChute™, fax or email in accordance with the Settlement System Code as defined in the Service Policies.

If a Retailer uses an Agent, the Retailer must provide the Client with written authorization for the Agent to conduct business on their behalf and the Client must provide a copy of such authorization to the Supplier.

If a Retailer uses an Agent, the Supplier will only send account-related information to the Agent. Duplicate information will not be sent to the Retailer. The Agent is responsible for keeping the Retailer informed of all activity and obligations.

The Supplier will only send information to one DropChute™ address and one e-mail address for each Retailer. One User ID and password will be provided to the Retailer for web access or other Systems used.

Client to Provide...	Format	Timing
Policy setting forth the Client's standards for transactions that can be sent by DropChute™ D2-205		

Customer Issue Management

The Supplier will work with the Client to resolve Site Customer and Account-related issues specific to distribution services in accordance with the Service Policies.

The Supplier will work with the Client to investigate and resolve issues or complaints received from Retailers specific to distribution services in accordance with the Service Policies.

Escalated Issues/Complaints

The Supplier will work with the Client to report and investigate escalated issues or complaints (written complaints and/or AUC, Member of the Legislative Assembly, Utilities Consumer Advocate Client Senior Management initiated). These escalated issues or complaints will be resolved in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on managing customer and account issues. D2-145	MS-Word	

2.8. Customer Care Advisories

Overview

The Client will provide Customer Care Advisories that may include overview, questions and answers, key messages, etc. to enable the Supplier to effectively respond to specific types of customer inquiries.

For planned situations, e.g., D-Tariff price changes, meter read frequency or route changes, change in corporate ownership, etc., the Client must provide the Supplier a reasonable amount of advance notice. A Statement of Work may be required.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Description of situation complete with scripts and Customer messages the Supplier will provide to staff.	MS-Word	

2.9. Customer Threats

The Supplier will manage threats to employees or Client facilities as per Service Policies.

Client to Provide...	Format	Timing
Policy that specifies the Suppliers management of threats to employees or Client facilities. D2- 925	MS-Word	

3. Account Management

This Section describes how the Supplier manages Customer Accounts for the Client, including:

- Account Organizational Structure
- Billing Models for Distributor Site Customers
- Customer Information
- Statement Accounts
- Retailer Service Accounts
- Distributor Site Customer Service Accounts
- Erroneous Enrollment
- Site Distribution Site Customer Contracts
- Financial Responsibility for Sites
- Field Orders
- Record of Account History
- Account Transfers
- Site Information

3.1. Account Organizational Structure

This Section explains how the Supplier manages accounts when Sites are Enrolled with Retailers or when the Client directly bills the Distributor Site Customer.

The Supplier's Service offering is based on how ATCO-CIS manages information. Each account is split into separate components. The different components are:

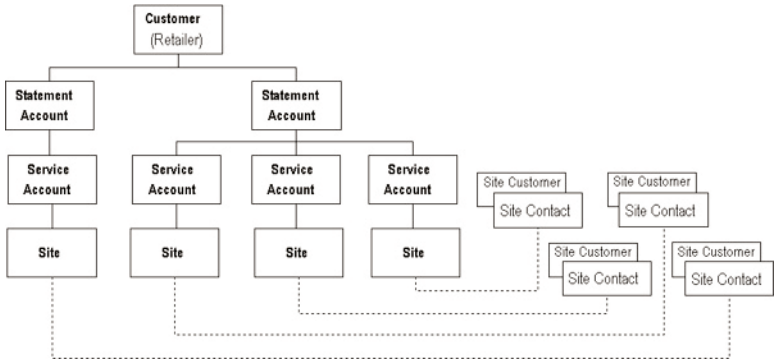
- Customer Information: Basic information on who the Customer is. For Sites Enrolled by Retailers, the Retailer is the Customer. When the Client directly bills the consumer, the Distributor Site Customer is the Customer.
- Statement Account: The financial portion of the account that combines charges from all Service Accounts.
- Service Account: The account for the actual product or distribution service provided by the Client to its Customers.
- Site Information: Information about the Site where the Client delivers the product, i.e., address, unique Site ID and the Site Contact.

Basic information about accounts:

- One bill is created for each Statement Account.
- Statement Accounts may have multiple Service Accounts, e.g., a Retailer or Distributor Site Customer with many Site locations.
- The Statement Account number does not change when Service Accounts are added or removed.
- A Service Account tracks financial responsibility for a Site.
- Each Service Account is connected to a Site.

Retailer Accounts

The diagram below shows an example of how these components are used to form the overall 'account' when a Retailer provides energy to a Site.



This example shows a Retailer with four utility services. Note that the Retailer is entered only once and that each Site has a Site Customer and Site Contact.

This Retailer receives two statements. One statement has a single Service Account. The other statement has three Service Accounts.

If a Site Customer or Site Contact changes and the Retailer continues to provide energy, the Service Account remains unchanged. The Site Customer and Site Contact information is end dated and then updated with new information but does not affect the financial responsibility of the Retailer.

If a Site Customer changes and the Retailer no longer provides energy, the Service Account is ended and the Site Customer and Site Contact is end-dated.

If a Retailer De-Enrolls then re-Enrolls the same location at a later time, a new Service Account is added. The prior Service Account remains ended and is not affected. The billing history for each Service Account is maintained separately.

Distributor Site Customer Accounts

The diagram below shows an example of how these components are used to form the overall 'account' when the Client directly bills the Distributor Site Customer, e.g., when a Site has been built but not yet Enrolled by a Retailer, or it not eligible for enrollment and the Distributor Site Customer pays for the D-Tariff charges.

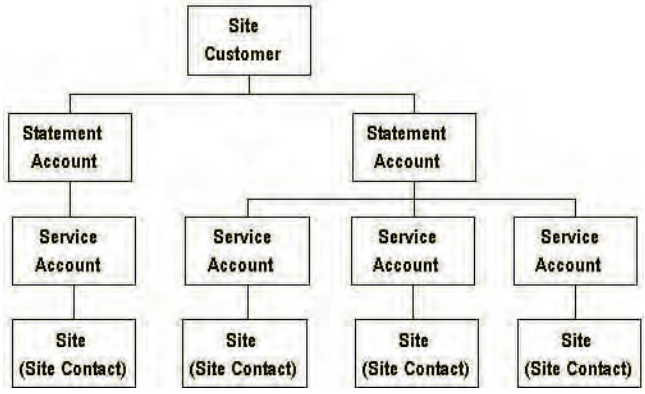


Figure 1

This example shows one way a Distributor Site Customer with four utility services can manage their accounts. Note that the Distributor Site Customer is entered only once.

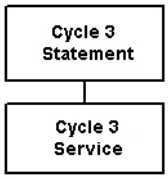
This Distributor Site Customer receives two statements. One statement has a single Service Account. The other statement has three Service Accounts.

Each Site can have Site Contact if the Distributor Site Customer designates one.

3.2. Billing Models for Distributor Site Customers

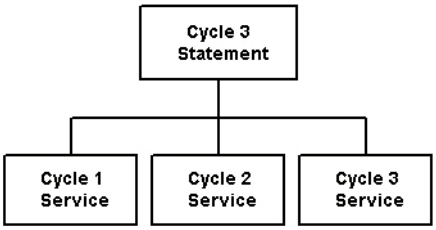
The Supplier will use ATCO-CIS to provide Distributor Site Customers with the following statement options.

A) Single Service Statements



These are statements with a single Service Account.

B) Consolidated Billing



This option allows a Distributor Site Customer to have multiple distribution services on one monthly statement. The statement cycle is selected by the Client to best manage revenue.

Fee Schedule: Statement of Work (expect to be rarely used)

Client to Provide...	Format	Timing
Policy on the use of billing options, e.g., minimum number of Service Accounts per Statement, if and when contract consolidated bills can be used, payment terms, etc. D2-240 Policy on managing statement and charge cycles and frequencies. D2-270		

3.3. Customer Information

Retailers

The Supplier will add a Retailer to ATCO-CIS after the Client notifies the Supplier that the Retailer has met all eligibility requirements. One record is added for each Retailer, including the following information:

- Legal name and aliases.
- General mailing address and phone number.
- Corporate registration number and date of incorporation.
- Retailer ID.
- Current eligibility for new Enrollments.
- Prudential requirement information including security or guarantee type, effective date, value, expiry date and identification of guarantor.
- Compliance or application testing, if required, is not included.

Retailer Site Customers, Site Contacts and Additional Responsible Parties

Adding Information

The Supplier will add Retailer Site Customers, Site Contacts, Additional Responsible Parties and Site Owners from information provided by Retailers in Update Customer Information (UCI) transactions (as defined in the SSC) using DropChute™. The information is automatically entered into ATCO-CIS.

Updating Retailer Site Customer Information

The Supplier will update information when the Retailer sends a UCI transaction to the Supplier with Retailer Site Customer, Site Contact, Additional Responsible Parties or Site Owner changes.

The Supplier can manually update Site Contact information in ATCO-CIS when advised of changes by the Retailer Site Customer, Site Contact or ARP in accordance with the Service Policies. If the Supplier manually updates the information, the Retailer Site Customer, Site Contact or ARP must also contact the Retailer. Information entered by the Supplier is overwritten by UCI transactions sent by the Retailer at a later date.

The Supplier can follow up on UCI information that does not match information in ATCO-CIS in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on whether or not the Supplier is to manually update Site Contact information for retail Sites. D2-260		
Policy on following up on UCI transactions that do not match information in ATCO-CIS. D2-261		

Distributor Site Customers

Distributor Site Customers are end use Customers at a Site whom the Distributor bills directly. As Distributor Site Customers are identified by the Client, the Supplier will add Distributor Site Customers into ATCO-CIS. After receiving information on a new Site from the Client one customer record is added for each Distributor Site Customer, including the following information:

- Legal name and aliases.
- General mailing address and phone number.
- Meter and transformer information.
- Applicable price schedules.

Updating Distributor Site Customer Information

The Supplier changes Distributor Site Customer information when advised by the Distributor Site Customer or the Client. It is the Distributor Site Customer's responsibility to notify the Supplier of name, address and phone number changes in a timely manner.

3.4. Statement Accounts

Creating New Statement Accounts

The Supplier will create new Statement Accounts as per the billing models selected by the Client. New Statement Accounts are typically required when:

- A new Retailer starts service in the Client's territory.
- A Distributor Site Customer is to be billed directly by the Client.
- The Client requests the Supplier to create a new Statement Account for better management of accounts receivable.
- When the Supplier determines a new Statement Account is required for system efficiencies.

Statement Cycle and Frequency

The Supplier will assign each Statement Account to one of the Supplier's twenty (20) monthly bill cycles in accordance with the Service Policies.

The Supplier will create statements on the scheduled statement cycle. The Supplier will not create off cycle statements for off cycle charges in accordance with the Service Policies.

The Supplier can change statement cycles as directed by the Client. Changing a statement cycle allows the bill to be sent on a specified day of the month. The Client must provide the Supplier with policies on changing the statement cycle.

This practice is important for managing cash flow when there are multiple Service Accounts read on different cycles on the same statements. Some considerations are the charge amount, number of other Service Accounts on the bill and the difference in read cycles.

Client to Provide...	Format	Timing
Policies for changing the charging and statement cycles. These policies must clearly state the Client's revenue management objectives. D2-270		
Policy outlines how the Supplier will manage the Client's Tariff Bill Calendar and Site-Cycle Catalogue D2-265		
Policy on off cycle statements. D2-271		
Policy on when statements and tariff bill invoices can be voided and what the Supplier will do when this occurs. D2-553		

Statement Media

The Supplier will provide statements to Retailers in standard electronic file format in accordance with the Tariff Billing Code (Tariff Bill File). The Supplier can modify the content and format of this file with a Change of Service Request. The Supplier can provide Retailers with a paper summary that does not contain detailed information provided in the Tariff Bill File.

Distributor Site Customer Statements

The Supplier will provide Distributor Site Customers with a paper bill.

Special Handling

The Supplier can special handle Statement Accounts at the Client's request. These accounts are flagged for manual review before sending.

Additional Responsible Parties

The Supplier will track parties who share financial responsibility for a Statement Account in accordance with the Service Policies, i.e., a roommate, spouse, guardian or guarantor. These Additional Responsible Parties (ARP's) share financial responsibility for all Service Accounts on the statement.

The ARP does not receive a printed copy of the statement.

Depending on the number and length of ARP names, the name(s) may be printed on the statement or be shown as 'et al'.

Client to Provide...	Format	Timing
Policy on handling Additional Responsible Parties. D2-155	MS-Word	

Memo Statements

The Supplier can send printed copies of Distributor Site Customer statements to persons who do not have financial responsibility. These are typically accountants, district offices, an agent who manages accounts or a relative who manages the Distributor Site Customer's affairs while away. Memo Statements will only be provided when written authorization is provided to the Supplier in accordance with the Service Policies.

Additional Statement Copies

The Supplier can provide Distributor Site Customers with multiple copies of printed statements.

Client to Provide...	Format	Timing
Policy regarding the use of additional statement copies and memo statements. D2-280	MS-Word	

Preauthorized Payment Plan (PPP)

The Supplier will automatically withdraw payments from Retailer's and/or Distributor Site Customers' bank accounts as authorized by such Customer. Refer to the PPP Section for more information.

Client to Provide...	Format	Timing
Policy on acceptable forms and methods of payment. D2-585 Policy on criteria for managing Pre-Authorized Payment Plan. D2-594	MS-Word	

Statement Account Maintenance

The Supplier maintains basic Statement Account information, changing items as requested by the Retailer or Distributor Site Customer. For example, adding or removing PPP or changing the statement mailing address.

3.5. Retailer Service Accounts

Enrollments / Adding New Service Accounts

The Supplier will Enroll a Retailer as the energy provider for a Site and create a new Service Account in ATCO-CIS when a qualified and approved Retailer sends an Enrollment request via **DropChute™**.

The Supplier will accept Enrollment requests from Retailers via **DropChute™**.

The Supplier will validate Enrollment requests and determine whether they conform to the content and format requirements of the SSC.

If the Enrollment request does not conform, the Supplier will reject the Enrollment request, and notify the Retailer of the failed Enrollment.

If the Enrollment request passes validation tests the Supplier will process the Enrollment request, and notify the Retailer of the successful Enrollment.

If a Retailer does not request a physical connection for a disconnected Site, the Site will be Enrolled and the Service Account will be set up, but the Site will not be connected.

The Supplier will apply the Client's distribution price schedules, distribution service fees, and charge cycle applicable for each Service Account as provided by the Client.

The Supplier can request and process additional Enrollment information from Retailers in accordance with the Service Policies. **(optional)**

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Applicable price schedules and distribution service fees for Enrollments. D2-290	MS-Word	Before Service Commences
Policy on processing enrollments. D2-295		
Policy on the management of Tariff Bill Reject (TBR); the Tariff Bill Reject Notification (TRN); and the Tariff Bill Dispute TBD transactions. D2-575		

Following up on Enrollments

The Supplier can follow-up manually on specific successful Enrollments in accordance with the Service Policies, e.g., Confirmation of enrollment via email or phone call.

The Supplier can follow-up manually on failed Enrollments when requested by a Retailer in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy clarifying when to follow up on failed Enrollments when requested by Retailers and what actions can be taken. D2-300	MS-Word	

Energize Sites

The Supplier will process and validate the Retailer's request to energize a Site in addition to, and separate from, the Enrollment request.

If the Client advises the Supplier that the Site has been connected, the Supplier will record that information and the Retailer will be notified electronically via the Site Metering Characteristics transaction and in accordance with the SSC.

Client to Provide...	Format	Timing
Policy on the conditions that must exist for service connection or reconnection D2-325 Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327 Policy defining financial responsibility for sites. D2-322	MS-Word	

Service Account Maintenance

The Supplier will make individual changes to Service Accounts including:

- Changes to the charge cycle as provided by the Client.
- Changing the assigned distribution access price schedules.
- Use Class/Type of business, etc.
- Service status, e.g., standby, safety disconnect, etc.
- Special handling requirements.

Mass changes to Service Accounts require a Statement of Work.

De-Enrollments / Ending Retailer Service Accounts

Individual De-Enrollments

The Supplier will De-Enroll individual Sites in accordance with the Service Policies when requested by Retailers, including the following tasks:

- End the Retailer's Service Account and advise the Retailer of final billing issues, e.g., distribution service fees.
- If the Site is not eligible for the regulated rate, notify the Default Supplier if another Retailer does not Enroll the Site, or, if the Site is eligible for the regulated rate, notify the regulated rate provider.
- Prepare the final charges.
- End the Site Contract.

Client to Provide...	Format	Timing
Policy on when the Supplier will receive, process and/or cancel de-enrollment requests from Retailers. D2-310	MS-Word	

De-Enrollment Cancellations

The Supplier will cancel De-Enrollment requests received from Retailers via the optional Revoke De-Select Request transaction in accordance with the Service Policies.

The Supplier will cancel De-Enrollments at the request of the Retailer who submitted the De-Enrollment, in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on defining financial responsibility for sites. D2-322	MS-Word	

Mass De-Enrollments

The Supplier will process Mass volume De-Enrollments in accordance with a Statement of Work, e.g., Retailer Bankruptcy or when a Retailer discontinues energy service to a Mass volume of Retailer Site Customers.

Fee Schedule: Statement of Work

Working with the Default Supplier

The Supplier will notify the Default Supplier of De-Enrollment requests and the status of De-Enrollments and will notify the Default Supplier for Enrollments in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on defining financial responsibility for sites. D2-322	MS-Word	

De-Enrollment and Enrollment Errors

The Supplier cannot change Enrollment or De-Enrollment dates after they have been processed, e.g., if a Retailer Enrolled an incorrect Site or requested Enrollment for the wrong date.

The Supplier can manually calculate charges as directed by the Client and create one time charges or credits to the affected Service Accounts in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on De-Enrolling Sites, e.g., number of days to wait before De-Enrolling, action to be taken to identify the new Site Customer, when to advise Default Supplier, canceling De-Enrollments, etc. D2-310	MS-Word	
Policy on when and how the Supplier is to calculate and apply one time charges or credits to adjust for discrepancies in Service Account start and end dates due to enrollment errors after-the-fact. D2-315		
Policy defining the Client's responsibility for managing financial responsibility for sites both connected and disconnected. D2-322		
Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327		

3.6. Distributor Site Customer Service Accounts

Isolated Sites and Rural Electrification Association Limited (REAL's)

Distributor Site Customer Service Accounts include accounts for Isolated Sites. They also include accounts for the Manning and Lakeland Alberta Rural Electrification Area (REAL). The Supplier will manage these accounts in the same manner as other Distributor Site Customer Service Accounts except for the following:

- Accounts for Isolated Sites are:
  - also billed for energy provided by the Client from local generating facilities,
  - not enrolled with Retailers,
  - manually started and ended by the Supplier.
- Accounts for the Manning and Lakeland REAL are:
  - only billed on the transmission component of the distribution charges and are not billed for the distribution component,
  - based on reads provided by the Manning REA and Lakeland REA,
  - included in the Client's load settlement services.

The Supplier can provide other services for Isolated Sites or for other REAL's.

Fee Schedule: Change of Service Request

Client to Provide...	Format	Timing
Policy on managing Independent Distributor accounts D2-930	MS-Word	

Adding Distributor Site Customer Service Accounts

The Supplier will manually add a new Service Account in ATCO-CIS when:

- Requested by the Client.
- When the Distributor Site Customer is to be billed directly for special charges in accordance with the Service Policies.
- When a Site is De-Enrolled and disconnected and the Distributor Site Customer is to be billed directly in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on creating Service Accounts for Distributor Site Customers. D2-347	MS-Word	

Maintaining Distributor Site Customer Service Accounts

The Supplier will maintain basic information on Distributor Site Customer Service Accounts including:

- Changes to the charge cycle as provided by the Client.

- Changing the assigned distribution access price schedules.
- Changing the Use Class/Type of business, etc.
- Updating special handling requirements.

Ending Distributor Site Customer Service Accounts

The Supplier will manually end a Distributor Site Customer Service Account when requested by the Client or when another Distributor Site Customer advises the Supplier that they are taking responsibility for the Site.

The Distributor Site Customer Service Account is automatically ended when a Retailer enrolls a Site.

3.7. Erroneous Enrollment

The Supplier will work with the Client to resolve situations where a Site is enrolled in error by a Retailer, in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on actions the Supplier is to take for handling site enrollment errors. D2-315	MS-Word	

3.8. Distributor Site Customer Contracts (Optional)

The Supplier can administer the Client's contracts with Distributor Site Customers if requested by the Client. The Client must provide the Supplier with a copy of the contract or a detailed summary of billing terms to be entered into ATCO-CIS. In all circumstances, the Client is responsible for determining its contractual requirements and for informing the Supplier of same.

The Supplier is responsible for:

- Entering contract terms into ATCO-CIS.
- Applying contract terms to monthly billing of Distributor Site Customer Service Accounts, in accordance with the Service Policies.
- Administering specific contract terms.

The Supplier will enter the following billing factors as requested:

- Minimum dollar amount.
- Minimum usage and/or demand amount.
- Penalties for non-compliance.
- Length (days, months, or years).

Client to Provide...	Format	Timing
Contract details whenever new contracts are negotiated or existing contracts are changed.	MS-Word	
Policies for applying contract penalties, transferring contracts, ending contracts before the specified end date when a customer moves, etc., including the amount of discretion the Supplier has. D2-330		

3.9. Financial Responsibility for Sites

General Information

The following table summarizes who is responsible for charges in various situations.

	Retailer Enrolled	Not Enrolled
Connected	Retailer	Not Allowed – Enroll with Default Supplier
Disconnected	Retailer or Default Supplier	Client or Distributor Site Customer in accordance with the Service Policies

Connected: Energy is flowing. The Site is physically connected to the Client's distribution system.

Disconnected: Energy is not flowing. The Site is physically disconnected from the Client's distribution system. Includes seasonal and safety disconnects.

Activities Undertaken

The Supplier will manage financial responsibility for charges in accordance with the Service Policies, e.g., notify the Default Supplier within a predetermined number of days of a De-Enrollment request, request the Client to make a Site visit to determine who is at the Site, etc.

The Supplier will undertake specific actions including:

- When a Site is De-Enrolled, the Supplier will notify the Default Supplier within the timeframe specified in the Service Policies.
- Notify the Default Supplier if the Site is Enrolled by another Retailer.
- When new Sites are built, the Supplier will create a Service Account for the Distributor Site Customer if the Site is not Enrolled with a Retailer as per the Service Policies.

The Supplier can take additional actions to manage financial responsibility for Sites as requested by the Client **(optional)**.

Fee Schedule: Statement of Work or Change of Service Request

Client to Provide...	Format	Timing
Policy on managing financial responsibility for Sites. D2-322	MS-Word	

3.10. Field Orders

Role of the Supplier and the Client

The Supplier will create Field Orders submitting them to the work management system as per the Service Policies when the Supplier determines field work is required (e.g., when a customer calls regarding a damaged street light). The Supplier will also create a Field Order when Retailers or Site Customers request field work. These situations may also be identified by the Supplier's quality assurance processes or when the Supplier is contacted by the Client.

In all instances, the Client is responsible for providing the complete and accurate information back to the Supplier in a reasonable timeframe, e.g., meter reads, equipment identifiers and, where applicable, instructions for billing adjustments.

The Supplier is responsible for communicating non field work requests (e.g.: confirmation of price schedule, energize date confirmation, meter change discrepancies) to ATCO Electric staff in accordance with the Service Policies.

The Supplier will contact the Retailer Site Customer or Retail Site Contact as provided by the Retailer when necessary.

The Supplier is responsible for the completion of work requests as per the Service Policies.

Client to Provide...	Format	Timing
Policy on when the Supplier will initiate a field work request to the Client. D2-380	MS-Word	

Fieldwork Initiated by the Client

The Client will create a Field Order in ATCO-CIS for locally initiated fieldwork and will notify the Supplier of changes being made that affect charging upon completion of that work request. The Client must enter complete and accurate information into the Work Management System, e.g., meter equipment numbers, dates and readings. Additional instructions may be communicated to the Supplier as per Service Policies.

Client to Provide...	Format	Timing
Policy defining the Client's responsibility to inform the Supplier when the Client completes field work without a Field Order request initiated by the Supplier. D2-380	MS-Word	

Non Field Work Requests

The Supplier will communicate with the Client on distribution service-related matters that do not require field work as per Service Policies, e.g., meter read, service connections or disconnections discrepancies.

The Supplier can send requests for work to the Client using other methods specified in the Service Policies. The Client can send work request completions to the Supplier using the same methods as per the Service Policies. **(optional)**.

Fee Schedule: Statement of Work

Providing Updates on Work Request Status

The Supplier will advise the Site Customer or Retailer of the status of fieldwork in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when the Supplier will advise the Site Customer or Retailer of the status of Work Requests. D2-380	MS-Word	

Completing and Returning Orders

The Client must return work request completion files to the Supplier in a reasonable timeframe, or will provide update information when a work request cannot be returned in a timely manner. If the Field Order cannot be completed, it will be cancelled with notes to indicate the reason for non-completion by the Client.

Field Order History and Monitoring

The Supplier will retain a history of Field Orders in ATCO-CIS. The Supplier monitors the status of Field Orders they have initiated in ATCO-CIS and follows up on those not completed by the requested date as per the Service Policies.

The Client is responsible for maintaining a history of information in their Work Management Systems. The Client is also responsible for monitoring and following up on the Field Orders they have initiated in ATCO-CIS.

Charges for Work Requests and Field Orders

The Supplier will calculate charges for Field Orders and apply charges to Service Accounts in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when the service fees will be charged and/or waived by the Supplier. D2-510	MS-Word	

External Order Requests

The Supplier will process and validate requests for field work that are sent by retailers to energize, de-energize or read meter for a site as per the Service Policies.

The Client will send completion data via their Work Management System to the Supplier. The Supplier will retain the information and the Retailers will be notified electronically in accordance with the SSC.

Client to Provide...	Format	Timing
Policy on when the Supplier will initiate a fieldwork request for Retailer requests. D2-325	MS-Word	
Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327		

Other Client Order System (Optional)

The Supplier can coordinate fieldwork using other Systems provided by the Client. Systems interface design, data exchange requirements and business processes must be defined in a Statement of Work.

Fee Schedule: Statement of Work and/or Change of Service Request

Coordinating Orders with Third Parties (Optional)

The Supplier can coordinate account-specific activities with third parties on behalf of the Client using Field Orders, e.g., if the Client contracts a third party to obtain special meter reads or process meter exchanges.

Fee Schedule: Statement of Work or Change of Service Request

Client to Provide...	Format	Timing
Policy on the use of and charges for Field Orders. D2-380	MS-Word	
Policy clarifying the situations when the Supplier is to create Field Orders when the Client advises the Supplier of field work already completed or to be completed. D2-380		
Policy clarifying whom of the Client's employees can request Field Orders. D2-380		
Policy on when the Supplier is to contact Retail Site Customers, Distributor Site Customers, Site Contacts, ARP's or Retailers on the status of field work. D2-380		
Policy on what information is to be included on Field Orders sent to the Client and returned to the Supplier. D2-380		
Policy defining the Client's responsibility to inform the Supplier when the Client completes field-work without a Field Order request initiated by the Supplier. D2-380		

3.11. Record of Account History

Electronic Data

The Supplier will maintain the following electronic account history:

Item	Criteria	Retention Period
Online Audit Trail	n/a	12 months
Statement Summary	n/a	24 months
Statement Details	n/a	12 months
Statement Images	n/a	3 months
Payments	n/a	24 months
Metering and Usage	All Rates	24 months
Charge	All Rates	24 months
Site Customer, Statement Account & Service Account	N/A	N/A

The Supplier can provide additional account history online or in other formats **(optional)**.

Fee Schedule: Statement of Work

The Supplier can retrieve archived information when requested by the Client.

Paper-Based Information

The Supplier will retain paper-based financial transactions, reports and other financial documents in accordance with the Service Policies. (**optional**)

Fee Schedule: Pass-Through Charges (off-site storage)

Client to Provide...	Format	Timing
Policy defining the requirements for retaining customer account information and reports. D2-390	MS-Word	

3.12. Account Transfers

The Supplier reserves the right to transfer Statement Accounts or Service Accounts at the Supplier's Discretion for System efficiencies, e.g., when the number of Service Accounts on a single Statement Account adversely affect System processing. These transfers will be done within the same statement cycle. The Supplier will inform the Client and the Retailer or Distributor Site Customer when the Supplier makes this type of transfer.

Client to Provide...	Format	Timing
Policy on when the Supplier will create a new Retailer Statement Account when the number of service accounts exceeds an efficient processing level. D2-270		

3.13. Site Information

Site ID List

The Supplier will create Site IDs and publish daily a list of Site IDs in accordance to the SSC. The Supplier will publish the Site IDs on the Client's web site.

Client to Provide...	Format	Timing
Policy defining how the Client's Site ID list will be made available to Retailers. D2-205	MS-Word	

Basic Site Information

The Supplier will manage basic Site information as provided by the Client including the address, installed equipment and parties responsible for the Site (e.g. Retailer, meter data manager, etc.) in accordance with the Service Policies. The Client will also manage selected Site information, e.g., Adding new Site Contacts.

Client to Provide...	Format	Timing
Policy defining the Supplier role in creating new sites. D2-421	MS-Word	

Customer-Specific Site Information

The Supplier can manage customer-specific Site information including:

- Site Contact for emergencies and Client distribution service-related matters.
- Annual usage.
- Service connection status.

Client to Provide...	Format	Timing
Policy defining the Supplier's role in updated Site Contact Information. D2-260 Policy defining the Supplier's role in following up on UCI information from Retailers. D2-261		

New Service Locations

The Client will enter information on new Sites (e.g. premises address, district, Site Customer, Site Contact) into ATCO-CIS when a new Site is requested, and prior to it being constructed whenever possible.

The Supplier will update other meter or Site information provided by the Client (e.g. installed equipment, price schedule information).

Client to Provide...	Format	Timing
Annual usage values for all use classes. Policy for the use of System versus manually entered annual usage for read estimates and billing. D2-440 Policy on the Supplier's role on creating new sites. D2-421	MS-Word	Before Service Commences

Meter Read Route and Sequence

The Client will plan and manage meter read routes and frequency as described in Article 4.1 (General).

Service Connections and Disconnections

The Supplier will process requests for service connections and disconnections in accordance with the Service Policies.

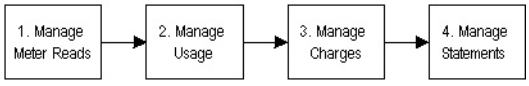
Client to Provide...	Format	Timing
Policy for processing requests for service connections and disconnections. D2-325 Policy on how the Supplier will manage Retailer requests to cancel a de-energize order. D2-327	MS-Word	

4. Revenue Management

This Section describes how the Supplier will manage meter reads for the Client, including:

- Information Managed by the Client.
- Information Managed by the Supplier.
- Automatic Meter Reading (AMR).
- Manual Meter Reads.
- Customer Provided Meter Reads.
- Off Cycle Meter Reads.
- Estimating Meter Reads.

This Section describes how the Supplier manages revenue for distribution charges based on meter reads, price schedules and other information provided by the Client. The basic steps in managing revenue are depicted and described below.



4.1. Managing Meter Reads

Information Managed by the Client

The Client will provide the Supplier with meter reads to be used for billing. The Client will plan and manage meter read routes and frequency. The Client will enter this information into ATCO-CIS. The Supplier will use the information entered by the Client to determine download and charge timing.

The Client is responsible for ensuring the quality of the meter reads and will research meter reads flagged for Client review based on parameters provided by the Client and entered into ATCO-CIS by the Supplier.

The Client is also responsible for researching meter reads and usage identified by the Supplier through Retailer or Site Customer interactions.

Information Managed by the Supplier

The Client will work with the Supplier to prepare annual meter read and download schedules. The Supplier can accommodate changes to the schedules if ten (10) Business Days prior written notice is provided. Meter Read Schedule changes may require a Statement of Work and/or Change of Service Request at the Discretion of the Supplier.

The Supplier will track energy and demand meter readings with the following units of measure:

- Watt
- Voltage
- Amps
- KwH

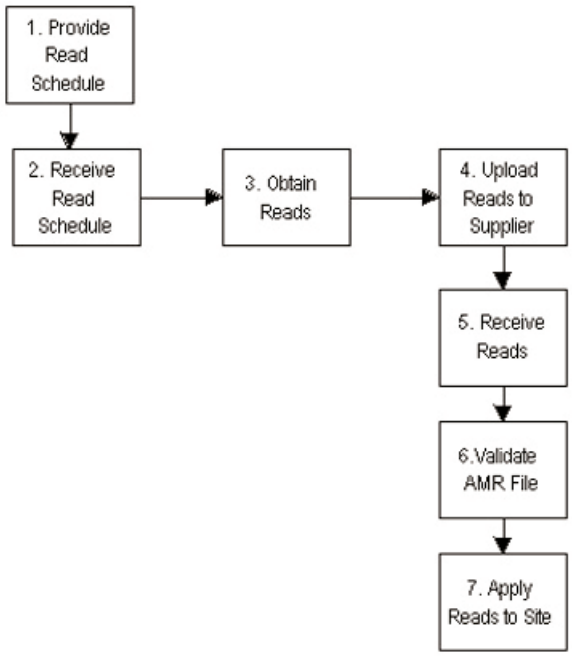
The Client will provide the following information for each meter read:

- Actual meter reading.
- Read date.
- Read method, e.g., AMR, Paper, etc.
- Read purpose.
- Meter number.
- Meter reader notes if applicable.

The Client will assign a status to each meter read, e.g., valid vs. invalid, use for charging vs. do not use for charging, based on validation parameters provided by the Client.

Automatic Meter Reading (AMR)

AMR meter reads will be managed as depicted and described in this Section.



1. Provide Read Schedule

- The Supplier will create a list of Sites to be read by AMR and will provide the list to the Client in an AMR data file on an agreed upon schedule.

2. Receive Read Schedule

- The Client will receive the data file from the Supplier.

3. Obtain Reads

- The Client will obtain the meter readings and assemble them into a data file.

4. Upload Reads to the Supplier

- The Client will send the file to the Supplier on a mutually agreed upon schedule, including the time of day specified by the Supplier.

5. Receive Reads

- The Supplier must receive the correct and complete file of meter reads from the Client on the mutually agreed upon schedule and time of day.

6. Validate AMR File

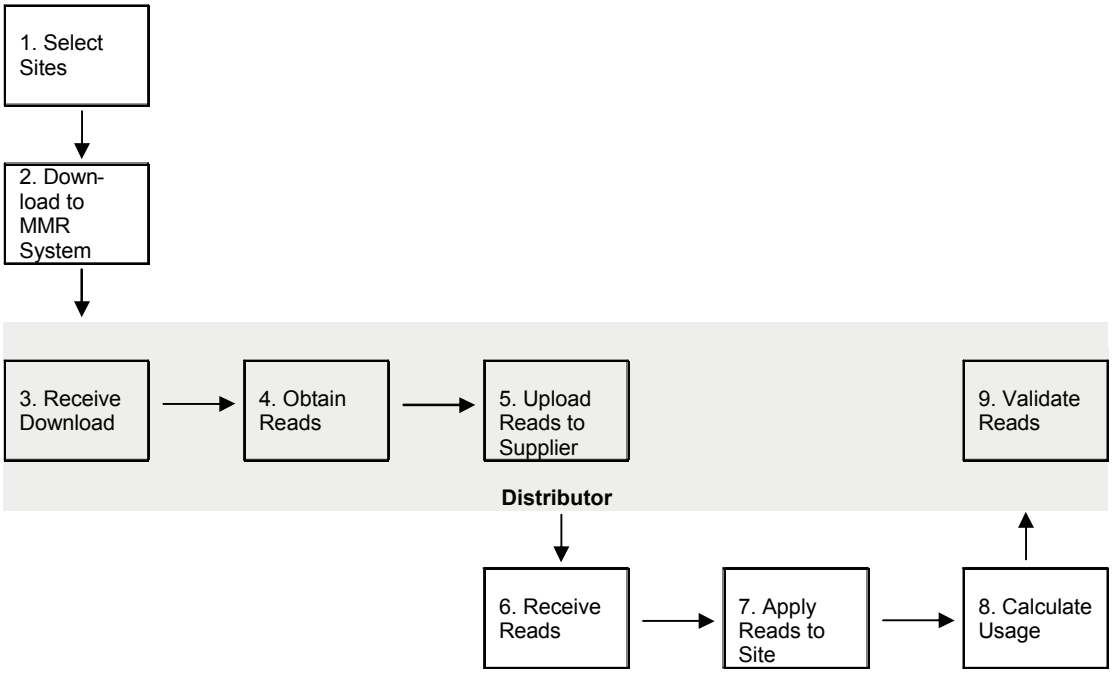
- The Supplier will validate AMR data file received against the request file sent to the Client. The meter reads are validated at a later time.
- The Supplier will contact the Client when a file fails validation.
- If a file fails validation, the Supplier will advise of the options available given the time available, the potential costs, operational and customer impacts:
    - Re-upload the file if time permits,
    - Proceed with billing without the data,
    - Delay billing.
- The Client will advise the Supplier what action to take.

7. Apply Reads to Site

- The Supplier will import the meter reads into ATCO-CIS, applying them to the appropriate meter.

Manual Meter Reads

Manual meter reads will be managed as depicted and described in this Section.



1. Select Sites

- The Supplier will select the Sites to be read using meter read cycle information from ATCO-CIS and the download schedule provided by the Client.

2. The Supplier File Transfers to Manual Meter Read System

- The Supplier will file transfer the information in accordance with the schedule provided by the Client.

3. The Client Receives the Manual Meter Read Information

- The Client will receive the file transferred from the Supplier.

4. Obtain Reads

- The Client will obtain meter readings for the requested Sites.

5. The Client File Transfers the Reads into ATCO-CIS

- The Client will send the file to the Supplier on the mutually agreed upon read schedule date and time.

6. The Supplier Receives Reads in ATCO-CIS

- The Supplier must receive the correct and complete file of meter reads from the Client on the mutually agreed upon read schedule date and time. If a file or files fail to file transfer, the Supplier will proceed with charging the

accounts without the data.

7. Apply Reads to Site

- The Supplier will apply the reads to the appropriate meter.

8. Calculate Usage

- The Supplier will calculate usage based on the reads provided. Any usage failing outside of the agreed to parameters will report to the Measured Usage Work Queue for further validation by the Client.

9. Validate Reads

- The Client is responsible for following up on all items that have failed usage validations and have appeared on the Measured Usage Work Queue.

Customer-Provided Meter Reads

The Supplier will accept meter reads provided by the Retailer, Site Customer or Site Contact in accordance with the Service Policies.

The Supplier will provide a "reasonability check" based on parameters stipulated in the Service Policies, and manually enter validated meter reads into ATCO-CIS.

Client to Provide...	Format	Timing
Policy on accepting meter reads from the Retailer, Site Customer or Site Contact. D2-450		

Off Cycle Meter Reads

The Supplier will request individual off cycle (special) meter reads from the Client in accordance with the Service Policies, e.g., when meter read provided is outside acceptable charge parameters, or when meter reads are missing for charging.

The Client can also obtain off cycle meter reads when following up on meter read and usage items in the Work Queue.

The Supplier will charge for off cycle meter reads in accordance with the Service Policies. For all Sites Enrolled with a Retailer, the Retailer will be charged for these meter reads in accordance with the Service Policies.

The Supplier can request Mass volumes of off cycle meter reads as directed by the Client.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Policy on when the Supplier will request off cycle meter reads. D2-460	MS-Word	

Estimating Meter Reads

The Supplier will use ATCO-CIS to calculate estimated meter reads based on the annual usage, degree days and actual meter reads according to the Service Policies, parameters and formulas. The Supplier or the Client will also manually calculate estimated meter reads using the Service Policies, parameters and formulas.

The Client or the Supplier will enter the estimated meter read into ATCO-CIS in accordance with the Service Policies.

The Supplier will normalize (calculated for an earlier date based on a later actual meter read) or prorate (calculated for a later date based on an earlier actual meter read) estimates in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when the Supplier will use a manual estimate, system generated estimate, pro-ration or normalization of meter reads for billing purposes. D2-470 Policy on when meter reads will be used for charging. D2-480	MS-Word	

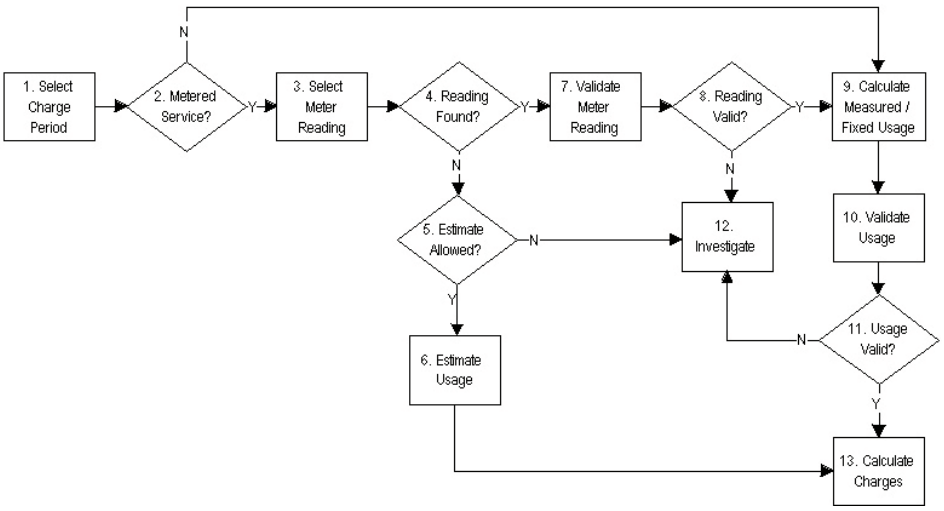
4.2. Converting Reads to Usage

The Supplier will calculate energy usage based on meter multiplier, meter equipment configuration information and meter readings supplied by the Client.

The Supplier will determine billing demand based on the Client's approved tariffs.

4.3. Managing Usage

The Client and the Supplier will manage usage as depicted and described below.



1. Select Charge Period:

- The Supplier will select the charge period for which usage is to be calculated, based on Service Policies.

2. Determine if Service is Metered:

- The Supplier will check the Site status to determine if Site is metered or unmetered.

3. Select Meter Reading:

- If Site is metered, the Supplier will select the appropriate meter read(s) in ATCO-CIS in accordance with the Service Policies.

4. The Supplier will determine if Reading is Found

5. If meter reading not found, the Supplier will determine if an estimated meter read is allowed:

- Check Estimated Allowed indicator and meter read history to determine if an estimate can be used in accordance with the Service Policies.

6. Estimate Usage:

- If an estimate is allowed, the Supplier will use the annual usage and degree days in ATCO-CIS to estimate the usage for the charge period.

7. If meter reading is found, the Supplier will determine if meter read can be used for Billing in accordance with the Service Policies.

8. Determine if Reading is Valid:

- The Client will validate the meter reading using parameters provided by the Client.

9. Calculate Measured/Fixed Usage:

- The Supplier will calculate usage based on meter reads, fixed usage for unmetered devices and billing factors based on information provided by the Client, e.g., meter multiplier.
- The Supplier will apply the usage to the appropriate Service Account and charge period, normalizing or prorating the usage in accordance with the Service Policies.
- If the Retailer changed at the Site during the period, the Supplier will prorate the usage and apply it to each Service Account at the Site based on the account start and end dates. The Supplier will also prorate usage for Price Schedule changes.

10. Validate Usage:

- The Supplier will validate the usage using parameters provided by the Client.

11. The Supplier will determine if usage is valid.

12. Investigate:

- The Client will follow up on items that fail validation, e.g., no meter reads when estimates are not allowed and when reads or usage fails validation.

13. The Supplier will calculate charges from usage.

Client to Provide...	Format	Timing
Policy on when the Supplier will use a manual estimate, system generated estimate, proration or normalization of meter reads for billing purposes. D2-470 Policy on when meter reads will be used for charging. D2-480 Policy on when the Supplier will accept Customer provided meter readings. D2-450		

4.4. Sending Usage to Retailers

The Supplier will create Daily Cumulative Meter (DCM) files in accordance with the Service Policies.

The Supplier will send DCM files to Retailers using DropChute™ in accordance with the Service Policies.

The Supplier will handle Retailer inquiries regarding DCM files and will investigate in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on what the Supplier will do to manage DCM data files sent to the Retailers. D2-664		

4.5. Managing Charges

The Supplier will manage distribution charges for Service Accounts using the charge schedules provided by the Client as described below.

1. Determine Price Schedule

- The Supplier will determine what price schedule(s) are to be applied to the service account as per Service Policies.

2. The Supplier will calculate charges

- Apply the price schedule(s) and contract term(s) to the service account.
- Calculate distribution service charge(s) as per Service Policies.

3. The Supplier will validate charge

- Apply the validation parameters to charges as per Service Policies.

4. The Supplier will determine if charge is valid

- Determine if charges are within the acceptable parameters provided by the Client.

5. Quality Assurance

- The Supplier will review charges that fail validation in accordance with the Service Policies.

6. The Supplier will update the annual usage

- The Supplier will update the system-calculated annual usage for the most recent 12 month period.

Client to Provide...	Format	Timing
Policy on when meter reads will be used for charging. D2-480	MS-Word	
Policy on quality assurance process in place for managing Daily Cumulative Meter data. D2-664		
Policy on when the Supplier will validate charges and meter readings for billing purposes. D2-500		

4.6. Quality Assurance

Supplier's Role

The Supplier will process system validations of meter reads, usage and charges using the Client specified parameters before using the information for charging.

Validations are processed automatically according to Client-provided, pre-defined parameters that take into consideration a number of factors such as usage profile, price schedule, time of year, weather and charging rules. Some examples of validations are:

- Measured usage requirements for the DCM.
- Auto cancel failures.
- Annual usage exceptions.
- High revenue exceptions.
- Meter read missing errors.
- Conflict in actual reads.

The Supplier will follow up on charge and/or usage-related items flagged for review in accordance with the Service Policies.

The Supplier will adjust charging when required and enter new information provided by the Client as a result of their investigation.

Client to Provide...	Format	Timing
Policy on what the Supplier will do to follow up on charges and reads that fail Client defined system parameters. D2-500	MS-Word	

Client's Role

The Client will review and follow up as required on read and usage-related items that fail validation in ATCO-CIS or parameters specified by the Client.

Prior to the scheduled charge cycle, the Client will notify the Supplier of any required billing adjustments or account updates that result from the Client's investigation, and the Supplier will use commercially reasonable efforts to adjust billing or update accounts for such scheduled charge cycle.

Client to Provide...	Format	Timing
Policy on what the Client will do to support the Supplier's investigation of charges and reads that fail Client defined system parameters. D2-500	MS-Word	

Increased Volumes of Items that Fail Validation

The Client must notify the Supplier in advance of special circumstances that may cause an increased volume of items flagged for review over the stated volumes noted in Schedule B (Service Levels). These changes typically occur when the Client changes business rules, meter read cycles or makes other business changes that affect meter reads or usage.

Fee Schedule: Statement of Work

4.7. Service Charges

Service charges are one-time charges applied to the Service Account or Statement Account. Service charges can be system generated or manually applied to such accounts. Recurring service charges (e.g., monthly administrative fees, basic customer charges or other flat-rate charges) are set up as part of a price schedule, not distribution service charges.

The Supplier will manually apply one-time charges to individual Service Account or Statement Accounts in accordance with the Service Policies. Some examples of one-time distribution service charges are charges for:

- Set-up costs.
- After hours fee.
- Non AMR Off cycle meter reads.
- AMR Read.
- Usage Information.
- Temporary disconnections.
- Re-connections.
- NSF Fee.
- Special reporting, data extracts or investigations.

Client to Provide...	Format	Timing
Policy on when the Supplier will assess service fees and/or waive service fees. D2-510	MS-Word	

The Supplier can apply Mass volumes of manually applied distribution service charges or changes to ATCO-CIS to automatically charge or waive distribution service charges, which will require a Statement of Work.

Fee Schedule: Statement of Work

The Supplier can also apply manually calculated one-time charges to Service Accounts as part of a complex billing arrangement, or a variable monthly administrative charge based on a combination of usage and number of Service Accounts **(optional).**

Fee Schedule: Statement of Work or Change of Service Request

Client to Provide...	Format	Timing
Policy on the amount of time the Supplier will spend investigating complex billing issues and when a Request for Service may be required from the Client. D2-543	MS-Word	

4.8. Complex Billing

The Supplier will manage complex billing accounts based on the current rate structure and billing methodologies that existed at the time of signing the Agreement. These accounts require a higher degree of quality assurance and/or manual processing.

These non-standard accounts are typically for:

- Time of use charging, e.g., pool price-based wires energy rates.
- Distribution Generator charging and credits.
- Interval metered accounts (especially those with non-standard transformation and metering configurations).
- Distribution Interchange charging.
- Stacked rates applied to the same usage.
- Complex contract terms.
- Application of special riders to larger accounts.

The Supplier will provide the following Services related to complex billing accounts:

- Prepare detailed analysis of demand and demand history for manually charged accounts.
- Manually calculate distribution charges and enter the charge amounts into ATCO-CIS.
- Calculate and apply Distribution Generator credits against charges and enter result into ATCO-CIS.
- Substantiate the quality of data by verifying calculations before and after entry into ATCO-CIS and on the statement.
- Process interval-to-interval or cumulative-to-interval meter exchanges.
- Perform cancel/recharges and adjustments.
- Process contract changes.
- Process new Site installations.
- Calculate energy charges for Isolated Sites that are complex accounts and enter the charge amounts into ATCO-CIS.

The Supplier will work with the Client's sales staff to resolve distribution rate application and interpretation issues, to explain complex billing calculations and to prepare support materials and documentation as requested to assist the Client in managing the Site Customer relationship.

The Supplier will work with the Client's meter data management staff to investigate and resolve issues identified by the Supplier related to missing or unusable meter data for complex accounts.

The Supplier will provide systems outside of ATCO-CIS to calculate charges as required at the time of signing. The Supplier will enter the complex billing charge and usage details into ATCO-CIS.

Price Structure Change

The Supplier can modify these systems as required when the Client changes price structure, or other factors that affect charge calculation methodology.

Fee Schedule: Statement of Work

Interconnecting Utility Distribution Owner Accounts

The Supplier will also manage accounts for interconnecting utility distribution owners. These are accounts for Sites at which the interconnecting utility distribution owner elects to interconnect their distribution facilities with the Client's distribution facilities to provide distribution access service in its service area using the Client's distribution system.

The Supplier will use a manual billing method to manage these accounts. The Services provided by the Supplier include:

- Setting up one Statement Account and one Service Account per utility company,
- Calculating distribution charges based on Client-provided reads and usage the Supplier obtains from ATCO-CIS or the Load Profiling and Settlement System (LPSS),
- Sending bills to the applicable utility distribution owner,
- Receiving payments, reporting and other activities as described elsewhere in this Schedule.

Quality Assurance

The Supplier will follow-up on all meter read, usage and charge-related items flagged for review by ATCO-CIS based on parameters provided by the Client, in accordance with the Service Policies. The Supplier will also follow-up on items in accordance with the Service Policies for items flagged for review by the Supplier during internal quality assurance processes.

This Section is based on the assumption that the Supplier will continue to manage the usage review for these specialized accounts.

Client to Provide...	Format	Timing
Policy on what the Supplier will do to follow up on the charges and read that fail Client defined system parameters. D2-500	MS-Word	
Policy on investigation of complex accounts. D2-543		
Policy on when adjustments can be made, approval requirements, communications with the Client and/or the Customer. D2-540		
Policy on when the Supplier will perform manual quality assurance validations following the change in format, rate structure, mass adjustments, content or system processing on electronic bills. D2-570		

Adjustments

The Supplier will make adjustments to complex billing Service Accounts and will follow-up with the Client, Retailers and Distributor Site Customers in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when the adjustments can be made, approval requirements, communications with the Client and/or the customers. D2-540	MS-Word	

Rate Comparisons

The Supplier will provide rate comparison information to the Client when requested by the Client, i.e., when a Customer is considering a rate change and wants to know what their charges would have been or will be on complex billing rates.

4.9. Federal, Provincial and Local Taxes and Surcharges

The Supplier will bill and collect all taxes (including Goods and Services Tax, sales, use, consumption, value added and similar taxes), duties, rates or levies of any nature whatsoever imposed upon, arising out of or in respect of Services and which the Client is obliged to collect (the "Consumption Taxes").

Such taxes do not include taxes on the Customer's net income, gain or capital of the Customer, payroll taxes/deductions applicable to Customer and municipal taxes imposed on Customer that are the responsibility of the Customer to pay directly to the taxation authority.

Certain Distributor Site Customers may be exempted from paying Consumption Taxes provided that they provide the Supplier with proof of exemption. Distributor Site Customer exemptions from taxes are managed at the Customer level (all accounts) on an account-by-account basis.

Client to Provide...	Format	Timing
Policy on Goods and Service Tax (GST) Exemptions. D2-522	MS-Word	

4.10. Site Customer Reports

The Supplier will provide usage reports with standard format and content to requestors as directed by the Client and will charge requestors for the reports in accordance with the Service Policies.

The Supplier can provide standard content and format reports including, meter reads, usage and charge history to Retailers, Site Customers and Site Contacts in accordance with the Service Policies.

The Supplier can provide requestors with custom reports as requested by the Client **(optional)**.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Policy on providing Customer Usage Reports. D2-523 Policy on customer authorization to release information to third parties. D2-180 Policy on communications with Retailers, Site Customers, and Site Contacts. D2-100 Policy on acceptable forms of requests. D2-110 Policy defines the acceptable circumstances for replacement or resending of data records, files and transactions. D2-115	MS-Word	

4.11. Price Schedules

The Supplier will manage the Client's price schedules for distribution tariffs. The Supplier will include pre-defined distribution service charges, e.g., connect fees, in price schedules.

The Supplier can manage price schedules for other products and distribution services **(optional)**.

Fee Schedule: Statement of Work

Unit Price Changes

The Supplier will change price schedules no more than once per month by entering unit price changes as provided by the Client.

The Supplier will test each unit price change for calculation accuracy and bill presentation. The Client must approve changes in writing before they will be implemented by the Supplier.

The Supplier can change price schedules more than once per month by entering unit price changes as provided by the Client, but such change may require a Statement of Work.

Fee Schedule: Statement of Work

Price Structure Changes and New Price Schedules (Optional)

The Supplier can change price structures, e.g., adding or deleting riders or creating new price schedules or new calculation methods as provided by the Client. New or changed schedules not supported by ATCO-CIS require a Statement of Work. The Supplier will work with the Client to determine how best to implement schedules within existing system functionality.

The Supplier will test each change for calculation accuracy and bill presentation using test data. Client must provide written approval of changes before they will be implemented by the Supplier.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Policy on approval of price/rate changes for both new and existing rates. D2-921	MS-Word-	

4.12. Account Adjustments

The Supplier will adjust Service Accounts on an account by account basis. Mass adjustments require a Statement of Work. This Section describes the adjustments that will be made by the Supplier, including:

- Types of Account-Specific Adjustments.
- Adjustments to Individual Accounts.
- Account Investigation.
- Off Cycle Statements.
- Voiding Statements or Tariff Bill Invoices.
- Special Considerations for Adjustments.
- Mass Adjustments (Optional).

Types of Account-Specific Adjustments

The Supplier can make account specific adjustments in ATCO-CIS using different methods.

- **Cancel:** used to reverse incorrect charges on a Service Account. Cancels always post to ATCO-CIS in real time, not an overnight batch. Subsequent to canceling charges, new information is entered, e.g., new meter reads or price schedules.
- **Re-charge:** used to automatically calculate charges for either missing or corrected charges for a Service Account after the incorrect charges have been cancelled. Re-charges post in the overnight batch process unless an immediate re-calculation is requested. Immediate recalculations are done at the Supplier's Discretion based on System availability.
- **Manual Re-charge:** used to enter manually calculated price components and usage for a Service Account that ATCO-CIS cannot automatically create. Manual re-charges post in the overnight batch process unless an immediate calculation is requested. All manual re-charges are sent to an electronic Work Queue for approval.

- **Charge Period Adjustment:** used to adjust specific charges for a Service Account. Charge period adjustments more than a pre-determined amount are sent to an electronic Work Queue for approval.
- **Miscellaneous Adjustment:** A revenue-only adjustment to either a Statement Account or Service Account. This type of adjustment does not apply to charge periods. Miscellaneous adjustments are utilized when an on-line calculation will generate a charge different than the desired outcome e.g. a negotiated settlement value.

The Supplier will process cancel/recharges manually or ATCO-CIS will automatically cancel/recharge accounts based on new meter reads or other information in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when adjustments can be made, approval requirements, communications with the Client and/or the customers. D2-540	MS-Word-	
Policy on following up on charge and reads that fail Client defined system parameters and may result in cancel and recharging. D2-500		
Policy on what actions the Supplier will take to investigate accounts. D2-543		
Policy on when the Supplier will void statements. D2-553		
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		

Adjustments to Individual Accounts

The Supplier will adjust individual accounts manually or automatically in accordance with the Service Policies based on information provided by the Client, e.g., completed Field Orders. Some examples of account specific adjustments are:

- Meter reading errors.
- Incorrect price schedule assigned.
- Non registering equipment.
- One-time adjustments made after negotiations with a Customer.

Adjustments are made to Service Accounts. Usage and charges must be recalculated and the financial impact is then posted to the applicable Statement Account.

If required, a one time credit or charge can be applied to a Statement Account but history is not retained at a Service Account level.

Client to Provide...	Format	Timing
Policy on when adjustments can be made, approval requirements, communications with the Client and/or the customers. D2-540	MS-Word-	
Policy on following up on charge and reads that fail Client defined system parameters and may result in cancel and recharging. D2-500		
Policy on what actions the Supplier will take to investigate accounts. D2-543		
Policy on when the Supplier will void statements. D2-553		
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		

Account Investigation

The Supplier will investigate potential billing adjustments when requested by the Retailer, Distributor Site Customer or the Client, in accordance with the Service Policies. The Supplier will also investigate potential billing adjustments identified through internal quality assurance processes.

Client to Provide...	Format	Timing
Policy on when adjustments can be made, approval requirements, communications with the Client and/or the customers. D2-540	MS-Word-	
Policy on following up on charge and reads that fail Client defined system parameters and may result in cancel and recharging. D2-500		
Policy on what actions the Supplier will take to investigate accounts. D2-543		
Policy on when the Supplier will void statements. D2-553		
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		

Off Cycle Statements

For Retailers (Tariff Bill File, E-Bills and Consolidated Statements)

The Supplier will not send off cycle statements with adjusted charges for Tariff Bill File, E-Bills and consolidated statements. When the Supplier receives adjusted reads, the Supplier will make the appropriate adjustments and the revised charges will be sent on the next on-cycle statement.

For Distributor Site Customers

The Supplier will send off cycle statements when requested by individual Distributor Site Customers in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		
Policy on managing consolidated billing accounts. D2-240		

Voiding Statements or Tariff Bill Invoices

The Supplier will void statements / tariff bill invoices that have not and will not be sent, in accordance with the Service Policies. This is typically done when the Supplier finds errors and needs to regenerate the statement / tariff bill invoice. E.g. statement - print or calculation problems, an incorrect message, or when a statement was special handled for review and needs to be regenerated; E.g. tariff bill invoice - incorrect GST rate.

New statements / tariff bill invoices created after voiding will have a different due date.

Client to Provide...	Format	Timing
Policy on following up on charge and reads that fail client defined system parameters and may result in cancel and recharging. D2-500		
Policy on what actions the Supplier will take to investigate accounts. D1-543		
Policy on when the Supplier will void statements. D2-553		
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		

Special Considerations for Adjustments

Notification of Large Adjustments

The Supplier can contact Retailers or Distributor Site Customers directly when a significant number of Service Accounts have been adjusted on a Statement Account (e.g. an incorrect price schedule or meter read file was used for many Service Accounts) or, if the financial impact of an adjustment is greater than a predetermined amount, in accordance with the Service Policies.

The Client is to provide the Supplier with policies specifying what is considered to be a large adjustment and what action is to be taken by the Supplier.

Summary Billing Format

When multi-service statements are re-issued, all Service Accounts on the Statement Account are re-statemented.

Client to Provide...	Format	Timing
Policy on when adjustments can be made, approval requirements, communications with the Client and/or the customers. D2-540		
Policy on what actions the Supplier will take to investigate accounts. D1-543		
Policy on when the Supplier will issue off-cycle statements. D2-271		
Policy on manual quality assurance on electronic bills. D2-570		

Mass Adjustments (Optional)

The Supplier can make Mass adjustments to Service Accounts. Some examples of Mass adjustments are:

- Applying rebates retroactively.
- Allocating credits, e.g., market transition credits.
- Charging for deferral accounts.
- When a large volume of revised information is received from the Client, e.g., incorrect readings were sent or wrong unit price was used.

Fee Schedule: Statement of Work

4.13. Bill Production

Types of Bills

The Supplier will produce two types of bills as follows.

- Electronic Bills.
- Printed Bills

Electronic Bills

The Supplier produces electronic bills as follows:

- Created on one of the Supplier's 20 monthly billing cycles.
- Electronic bills are in comma separated value (CSV) format. They are not graphical representations of the bill.
- A separate file is sent for each Statement Account.

The Supplier will send Tariff Bill Files or E-Bills to Retailers using DropChute™. Printed invoices and a monthly invoice summary are also sent to the Retailer.

The Supplier can make revisions to the Tariff Bill format at the request of the Client.

Fee Schedule: Statement of Work or Change of Service Request

The Supplier will provide quality assurance Services related to Retailer electronic bills in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on managing electronic bills. D2-570 Policy on managing tariff bill invoicing. D2-235	MS-Word-	

Printed Bills

The Supplier will produce a one-page printed invoice for Retailers that contains a summary of their electronic bill charges for each cycle as follows:

- Printed on one of the Supplier's twenty (20) monthly billing cycles.
- Double-sided on standard, letter-sized, (8.5"x 11") paper.
- In black print.

The Supplier will produce a printed statement for Distribution Site Customers as follows:

- Printed on one of the Supplier's twenty (20) monthly billing cycles.
- Double-sided on standard, letter-sized, (8.5"x 11") Utility Bill Stock.
- In black print.

Quality Assurance – Statement Check

The Supplier will randomly check bills for:

- Basic presentation (layout / format).
- Print quality.
- Bill messages.
- File naming.

The Supplier will also check charge calculations including adjustments, deposit interest and other financial information using a report printed for each billing cycle. The report contains randomly selected accounts that represent the major types of accounts and billing situations, e.g., adjusted accounts and varying price schedules. The following scenarios are checked:

- Initial charges
- Final charges
- Recharges
- Prorated charges
- Rate changes
- GST Exempt

- Price Schedule Minimum (Distribution only)
- Billed Demand (Distribution only)
- Contract Minimum (Distribution only)
- Days out of range

The following verifications are performed for each of the above accounts:

- All Charges are calculating correctly
- Unit prices for each component
- Estimate usage
- Actual usage for Initial charges
- Correct demand value was selected for charging (i.e.: contract , ratchet, rate minimum or measured)
- Exemptions

Application	**ATCO-CIS Bills**
Multi Fold *(max 15 sheets)*	
Insert Type	*multi fold (max 15 sheets)*
Bill Size	8.5" x 11"
Insert Size Width (min / max)	8 ¼" to 8 ½ "
Height	3 ½"
Finish	Matte, Non-porous
Material	20 lb. to 80 lb. Non porous
Insert Type	Multi-fold
Fold Type	One end closed
Single Fold	
Insert Type	*One fold*
Bill Size	8.5" x 11"
Insert Size Width (min / max)	8 ¼" to 8 ½ "
Height	3 ½
Finish	Matte, Non-porous
Material	20 lb. to 80 lb.
Fold Type	Single closed

No Fold

Insert Type	*no fold*
Bill Size	8.5" x 11"
Insert Size width (min / max)	8 ¼" to 8 ½ "
Height	3 ½
Finish	Matte, Non-porous
Material	Card stock – Non porous
Insert Type	**[Name of insert]**
Fold Type	Closed

Distribution

The Supplier's standard method for shipping physical product is by Canada Post, bulk ground mail.

The Supplier will use commercially reasonable efforts to meet Canada Post standards to qualify for discounts. This practice includes complying with Canada Post addressing standards and delivering materials to Canada Post in the specified manner.

Fee Schedule: Pass-Through Charges

Printed Bill Format Maintenance

The Supplier can make minor changes to the text on the statement, e.g. line item descriptions and the back of the bill, at the request of the Client.

The Supplier can make changes to the basic statement layout if requested by the Client.

Fee Schedule: Statement of Work or Change of Service Request.

Envelopes

All envelopes containing bills and letters sent to Customers will have the Client's name and the Supplier's return address.

The return envelope for remittance will be in the Client's name and have the Supplier's address. The Supplier will enclose return envelopes for Customers who pay through mail only or for Customers who have specifically requested an envelope. ATCO-CIS determines if a return envelope is included based on past payment methods, in accordance with the Service Policies.

Fee Schedule: Pass-Through Charges

Inventory Management

The Supplier will monitor stock levels and purchase materials on behalf of the Client, i.e., paper and envelopes.

Fee Schedule: Pass-Through Charges

Inserts

The Supplier can insert up to five (5) items, to a maximum of fifteen (15) sheets*, including the return envelope with each statement. The Supplier will include inserts as directed by the Client. Inserts must meet the following standards.

- Fifteen (15) sheets* maximum per mailing set including the return envelope, bill and all inserts.
- Typical set configuration = (one (1) page bill) = three (3) sheets.
- Return envelope (tear-off bangtail) = four (4) sheets.
- Return envelope (standard) = three (3) sheets.

* Each "layer" of paper is considered a sheet, e.g., an 8.5" x 11" paper with two folds is considered three sheets.

Special Handling

The Supplier can special handle individual Statement Accounts at the request of the Client. Requests to special handle must be received with appropriate instructions no less than twenty four (24) hours prior to the scheduled bill print. Requests for the Supplier to handle Mass Quantities will be dealt with in accordance with a Statement of Work.

Client to Provide...	Format	Timing
Policy on the use of return envelopes. D2-581		

4.14. Miscellaneous Invoicing

The Client will periodically levy miscellaneous charges to customers for services not related to regular wires service charges (e.g. interval meter data requests, transformer rentals). Miscellaneous charges are not typically contained within the Client's published price schedules.

These charges are billed outside of ATCO-CIS.

Client to Provide...	Format	Timing
Policy defines the guidelines for miscellaneous invoicing. D2-582	MS-Word	

5. Receivables Management

This Section describes how the Supplier will manage receivables for the Client, including:

- Payments.
- Payments to Retailers Received in Error.
- Prepayments.

- Electronic Funds Transfers.
- Pre-Authorized Payment Plan.
- Refunds.
- Credit Management for Retailers.
- Credit Management for Distributor Site Customers.

5.1. Payments

General Information

The Supplier will accept and process payments from Retailers and Distributor Site Customers per Service Policies.

Payments are applied to Statement Accounts and then applied to specific charges for Service Accounts according to payment posting rules.

Payments from banks and other electronic sources are processed in nightly batches. The Supplier's remittance processing system sends payment extracts three (3) times each day. The payments are shown on each customer's statement account in ATCO-CIS the next day.

The Supplier processes single payments or Mass volume remittance from financial institutions or by mail.

Payments are made payable to the Client, not the Supplier, and are deposited into the Client's bank account.

Forms of Payment

The Supplier can accept payment from Retailers and Distributor Site Customers using the following methods in accordance with the Service Policies:

- Electronic Funds Transfer.
- Pre-Authorized Withdrawal.
- Cheques.
- Cash.
- Miscellaneous (Money Orders, Foreign Currency).
- Bank Payments.

Client to Provide...	Format	Timing
Policy on acceptable forms and methods of making payments. D2-585 Policy on Pre-Authorized Payment Plan. D2-594	MS-Word	

Payment Methods

The Supplier will accept payments from the following sources in accordance with the Service Policies:

- Direct mail.

- Courier.
- Financial Institutions.

Client to Provide...	Format	Timing
Policy on acceptable forms and methods of making payments. D2-585	MS-Word	

Information Required for Payment Processing

The Supplier requires payments to be accompanied with the complete Statement Account number, including the company number and check digit.

Payments received by mail should include the payment stub, general ledger account number or other identifying information.

Handling Payments

Payments are processed in a video monitored, secure area.

Split Payments

The Supplier applies payments to a single Statement Account unless accompanied by multiple Statement Account numbers and the amounts to be applied to each Statement Account.

Partial Payments

The Supplier prorates partial payments to the receivables for each Service Account, which are then applied to charges within the Service Account according to the standard posting rules.

Payment Posting Rules

The Supplier applies payments to Distributor Site Customers' Statement Accounts by the following priorities:

1. Statement with earliest due date.
2. Security deposits.
3. Charges for Services.
4. Connection, reconnection fees.
5. Service fees.
6. Late payment fees.
7. Bank fees.
8. Other charges or fees.

The Supplier can change payment posting rules when requested by the Client.

Fee Schedule: Statement of Work

Payment Balancing and Cash Controls

The Supplier controls and monitors payments received by:

- Reconciling all payments received and processed to the Payments Control report with the Client's bank account.
- Reporting payment information such as amount received and processed by source.
- Responding to audit requests.

Investigating Exceptions

The Supplier will investigate payment problems such as:

- Payments without a valid account number.
- Misapplied Payments.
- NSF Cheques, Debit/Credit Memos.
- PPP bank account closed.
- Failed PPP withdrawals.

The Supplier will assess charges to Retailers and Distributor Site Customers for investigation and returned item processing as per the fee schedule provided by the Client.

5.2. Payments to Retailers Received in Error

The Supplier will handle payments to the Retailer received in error, in accordance with the Service Policies, e.g., return to the Retailer Site Customer or forward to the Retailer.

Fee Schedule: Pass-Through Charges

5.3. Prepayments

The Supplier will accept and apply prepayments from Retailers or Distributor Site Customers, at any time, using normal payment rules and processes. If valid charges are outstanding when the prepayment is received, the prepayment will be applied to charges using normal posting rules.

The Supplier will not statement Retailers or Distributor Site Customers for the prepayment of goods or distribution services.

The Client provides prepayment instructions to Retailers or Distributor Site Customers.

5.4. Electronic Funds Transfers

The Supplier will manage electronic funds transfers (EFT's) deposited by Retailers or Distributor Site Customers into the Client's bank account in accordance with the Service Policies.

The Client will manage signed contracts for Retailer EFT's. The Supplier will manage signed contracts for Distributor Site Customer EFT's.

The Supplier will receive a written description of planned EFT's from Retailers or Distributor Site Customers on or before the day of deposit. The description must include the appropriate Statement Account Number(s) and Amount(s).

The Supplier will monitor Client's bank account in accordance with the Service Policies to check for EFT's.

EFT's deposited to Client's bank account before 4:00 p.m. MST will be applied to the designated Statement Account on the same Business Day, provided the Retailer or Distributor Site Customer has given the appropriate written notification of the deposit.

The Supplier will manually apply EFT payments to the appropriate Statement Account(s) on the same Business Day received, as directed by the Retailer or Distributor Site Customer.

The Supplier will follow-up on missing EFT's by contacting the Retailer or the Distributor Site Customer on the next Business Day.

The Supplier will follow-up on EFT's deposited without prior written notification by reviewing the accounts in ATCO-CIS. If the Supplier cannot determine the account to which the funds are to be applied, the Supplier will contact the Retailer or Distributor Site Customer immediately for instructions.

Client to Provide...	Format	Timing
Customer contract for Electronic Funds Transfers.	MS-Word	
Policy on when the Supplier will accept Electronic Funds Transfers from Customers. D2-585		

5.5. Pre-Authorized Payment Plan

The Supplier will administer, on behalf of the Client, a Pre-authorized Payment Plan (PPP) as a method for Distributor Site Customers to pay monthly statements in accordance with the Service Policies. PPP authorizes the automatic withdrawal of funds from a designated bank account.

Distributor Site Customers on PPP continue to receive a statement with charge details. The statement includes the amount to be withdrawn, the date of withdrawal, and a message indicating "*Pre-authorized Payment...Do Not Pay*." The statement is sent prior to withdrawal in accordance with the Service Policies. This practice allows the Distributor Site Customer sufficient time to ensure that adequate funds are available, or to inquire about the charges.

When a statement is set up on PPP, all Service Accounts associated with the statement are included on PPP.

Client to Provide...	Format	Timing
Policy defining acceptable forms and methods of payments. D2-585	MS-Word	
Policy defining criteria for participating in the Pre-Authorized Payment Plan. D2-594		

Setting Up PPP For Distributor Site Customers

The Supplier will set up a Distributor Site Customer's PPP information when the Client indicates a Distributor Site Customer has qualified for distribution

access and a signed application form is sent to the Supplier along with a voided personalized or company cheque.

If the withdrawal is from an account that does not have cheques, the Distributor Site Customer must provide a letter from its bank including the account information authorizing the withdrawal.

A Distributor Site Customer can have different Statement Accounts debited against different banks, or can have multiple Statement Accounts debited against the same bank account. Once bank information is set up, Statement Accounts can be associated with the bank information on file.

Withdrawal Limits

The Supplier can establish maximum PPP withdrawal limits for Distributor Site Customers in accordance with the Service Policies. Over-limit amounts are statemented for manual payment. The over-limit amount owing will be charged a late pay fee if not paid by the due date or if payment is returned NSF.

Bank Transmissions

The Supplier coordinates PPP requests with banks as follows:

- When the statement is produced, a payment request file is created and the date when the file is to be sent to the bank is established.
- The bank transmission date is five business days prior to the payment due date.
- Changes to the withdrawal amount are automatically updated in the bank transmission file prior to the transmission date.
- The payment request file contains the Statement Account number, the bank and branch number, bank account number, the amount to be withdrawn, and the withdrawal date (statement due date).

NSF Withdrawals

Withdrawal occurs early in the morning of the due date. If there are insufficient funds to cover the amount owing, the returned item is shown in ATCO-CIS and the Supplier will apply an NSF charge.

The Supplier will notify the Client when large NSF withdrawals occur, in accordance with the Service Policies.

Client to Provide...	Format	Timing
Policy on PPP, e.g., eligibility, withdrawal limits, days in advance to send statements, NSF charges, etc. D2-594 Policy on when the Supplier is to contact the Client regarding NSF withdrawals, e.g., for amounts over $x or from Retailer X. D2-612	MS-Word	

5.6. Refunds

Refunding Deposits to Retailers and Distributor Site Customers.

The Supplier will refund or apply a deposit and deposit interest to a Service Account as directed by the Client. Deposits and interest are automatically applied to the Service Account when the account is finalled.

Client to Provide...	Format	Timing
Policy for the refund of deposits including minimum time for deposits to be held and interest paid. D2-620	MS-Word	Before Service commencement

Refunding Credit Balances

The Supplier will refund credit balances to a Retailer or Distributor Site Customer when a Service Account is finalled.

Refund Method

The Supplier will provide refunds using the method specified in Service Policies (e.g., by cheque, apply to accounts, deposit to customer's bank account, etc.).

Fee Schedule: Pass-Through Charges

The Supplier can provide refunds for other circumstances as defined by the Client **(optional)**.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
Policy for the refund of credit balances including minimum refund amount and policies for applying credits versus issuing refunds. D2-620	MS-Word	Before Service commencement
Policy clarifying when prepayments may be refunded, e.g. when the Client advises that construction is not proceeding. D2-620		

5.7. Credit Management for Retailers

Obtaining Initial Credit Information (Optional)

The Supplier can obtain credit information from Retailers using a credit application form containing information required by the Client (e.g., legal name, credit rating from a major, reputable bond rating service company or bank references, supplier references, etc.).

The Supplier can also obtain information from the Retailer on their initial, expected and planned future customer base.

The Supplier can provide the Client with reports or extracts of detailed usage information on the Retailer's potential Sites.

Fee Schedule: Change of Service Request

Determining Creditworthiness (Optional)

The Supplier can provide input to Client regarding creditworthiness criteria.

The Supplier can provide the Client with an assessment of a Retailer's creditworthiness and prudential requirements based on the initial credit information provided in the Retailer Credit Application and the criteria provided by the Client.

The Client will advise the Supplier in writing when a Retailer has met the Client's prudential requirements.

Fee Schedule: Change of Service Request

Ongoing Review of Prudential Requirements (Optional)

The Supplier can provide the Client with an ongoing assessment of the Retailer's creditworthiness and adequacy of prudential requirements.

Fee Schedule: Change of Service Request

Reporting on Prudential Requirements

The Supplier will provide the Client with reports on the Client's current and projected accounts receivable for each Retailer using processes and reports that existed at the time of signing the Agreement.

Collecting Retailer Security (Optional)

The Supplier can assist the Client with collecting, managing, calculating interest for and refunding securities provided by Retailers.

Fee Schedule: Change of Service Request

Applying Retailer Security to Statement Accounts

If the Client decides to draw on a Retailer's security to apply to charges, the Client will arrange for funds to be transferred. The Supplier will apply the funds to the appropriate ATCO-CIS Statement Accounts.

Administering Legal and Legislated Credit Accounts (Optional)

The Supplier can administer legal and legislated credit accounts for Retailers including foreclosures, receiverships, etc., in accordance with the Service Policies and regulatory requirements.

Fee Schedule: Statement of Work

5.8. Credit Management for Distributor Site Customers

Managing Security Requirements

The Supplier will determine the security requirements of Distributor Site Customers as follows:

- Investigate account history and credit situation.
- Upgrade/downgrade credit ratings.
- Determine the appropriate security amount in accordance with the Service Policies.
- Determine the appropriate security form in accordance with the Service Policies (e.g. cash deposit, letter of credit, guarantor, etc.).
- Request deposit and/or other security.

- Monitor and report on deposit and/or other security.

Fee Schedule: Pass-Through Charges

Client to Provide...	Format	Timing
Policy on the acceptable amount and forms of security. D2-640	MS-Word	Before Service commencement

Collection Activities

The Supplier will undertake the following collection activities for Distributor Site Customers:

- Determine collectible amount including late pay fee and other penalties.
- Initiate collection action based on Service Policies and direction.

Client to Provide...	Format	Timing
Policy on when to undertake collection activity and what activities are to be taken. D2-650	MS-Word	Before Service commencement

Write-Off Accounts

The Supplier will write off Distributor Site Customer accounts as follows:

- Write off accounts receivable in accordance with the Service Policies.
- Send file to collection agency and manage funds collected in accordance with the Service Policies.

Fee Schedule: Pass-Through Charges

Client to Provide...	Format	Timing
Policy on writing off accounts, e.g., after x days, when less than x dollars, etc. and when to send to a collection agency. D2-660	MS-Word	Before Service commencement

Administering Legal and Legislated Credit Accounts

The Supplier will administer legal and legislated credit accounts for Distributor Site Customers including the following:

- Foreclosures, receiverships, etc.
- Statute protected account.
- Estate accounts.
- Work with bankruptcy trustees, receivers, government agents, etc.

6. Metering Equipment Inventory Management

This Section describes how the Supplier will manage the Client's metering equipment inventory, including:

- Client's Role.
- Meter Installation, Removal and Exchanges.
- Compliance with Measurement Canada.
- Meter Equipment Information Managed by ATCO-CIS.
- ATCO-CIS Equipment Subsystem.
- Equipment Reporting.
- Mass Changes to Equipment Inventory.

6.1. General Information

ATCO-CIS integrates Service Accounts with the management of equipment like meters, transponders and other inventoried devices. For example, when a meter is installed or removed from a Site, the meter inventory is automatically updated. Similarly, when meter testing is required, ATCO-CIS automatically creates the necessary sample groups.

The Services described herein are based on the assumption that the Client is the meter inventory manager. If another company manages the meter inventory, a Change of Service Request is required.

6.2. Client's Role

The Client is solely responsible for the physical and system management of installed and in-stock equipment items including purchasing, random sampling, testing, repairs, salvaging and other non-billing related activities related to managing equipment.

The Client is also responsible for providing the Supplier with the billing-related meter and load information (e.g., meter multiplier, current transformer rating, voltage/potential transformer rating, interval data, power factor, etc.).

6.3. Meter Installation, Removal and Exchanges

The Supplier will enter information on individual meter installations, removals and exchanges into ATCO-CIS as provided by the Client. The Client is responsible for initiating and performing the fieldwork.

The Supplier will contact the Client when the Supplier determines from account activity that equipment must be tested, repaired, changed or read. The Client is solely responsible for determining what action to take, for arranging any necessary field work and for providing information to the Supplier.

Fee Schedule: Statement of Work (mass exchanges)

6.4. Compliance with Measurement Canada

The Client is solely responsible for compliance with equipment-related regulations, i.e., Measurement Canada.

6.5. Meter Equipment Information Managed by ATCO-CIS

ATCO-CIS manages equipment used at Sites. It does not manage equipment used for multiple Sites, e.g., equipment at substations, transformers, wires, etc. The software will manage the following equipment related information:

- Equipment purchases.
- Tracking of installed and in-stock meters, transponders and other uniquely numbered equipment items directly related to the use of individual meters.
- Physical characteristics, (e.g., equipment types, numbers, number of dials, rating, etc.).
- Equipment groups, sampling, testing and recalls.
- Inventory reconciliation.

6.6. ATCO-CIS Equipment Subsystem

Client Access

The Supplier will provide the Client with inquiry and update access to the equipment inventory subsystem in ATCO-CIS as per Schedule D (Client's Systems).

The Client must adequately train users in the operation of the System before updating information and shall ensure that users comply with the Supplier's system access and security requirements.

Supplier Access

The Supplier will only update account-related meter information (e.g., meter exchanges and customer-provided meter reads). The Supplier will not update information directly in the equipment subsystem (e.g. add new equipment or enter test meter reads).

Client to Provide...	Format	Timing
Policy specifying when the Supplier can update information in the equipment subsystem, e.g., changing CT/VT associations. D2-663	MS-Word	Before Service commencement

Equipment Documentation and Training (Optional)

The Client is responsible for systems and procedural documentation and all training related to the equipment sub-system.

The Supplier can provide the Client with basic system documentation on the screens and fields in the equipment-related windows.

The Supplier can provide the Client with technical and human resources for documentation and training.

Fee Schedule: Statement of Work

6.7. Equipment Reporting

The Supplier will provide the Client with a list of standard and ad-hoc batch reports the Client can use to manage equipment items, including a sample and brief description of each report. Many of these reports can be printed by the Client when required.

The Supplier can provide additional reports on request **(optional)**.

Fee Schedule: Statement of Work

6.8. Mass Changes to Equipment Inventory

The Supplier can make Mass changes to the equipment inventory when requested by the Client, e.g., when the Client enters incorrect information for a batch purchase of meters **(optional)**.

Fee Schedule: Statement of Work

7. Load Settlement

7.1. Overview

The Lodestar Profiling and Settlement system (LPSS) allocates usage by hour and creates daily load settlement data. The Client, as the Load Settlement Agent, is responsible for providing daily load settlement data, by Retailer and Site, to AESO and the Retailers. The Alberta Electric System Operator (AESO) then allocates energy usage and invoices electric energy purchasers.

7.2. Roles and Responsibilities

The Supplier will schedule and run LPSS interfaces for load settlement. The Supplier will manually re-schedule and re-run jobs as required.

The Client will perform quality assurance processes on load settlement data.

7.3. Daily Extract from ATCO-CIS

The Supplier will run extracts from ATCO-CIS every Business Day to obtain data to be sent to LPSS as required by regulations as of the effective date of this agreement as follows:

- New Sites.
- Retailer switches.
- Metering characteristics.
- Key Site attributes, e.g. loss class, profile class, etc.

The Supplier will investigate and resolve problems with the daily extract process.

The Supplier will send the daily ATCO-CIS extract file to the LPSS for processing and will provide support and investigate problems if the interface fails or is incomplete.

The Client will identify and follow-up on data problems. The Supplier will provide support to the Client as required.

Quality Assurance

The Supplier will provide the following automated quality assurance services related to the ATCO-CIS and LPSS interface:

- Compare client identified key attributes between LPSS and ATCO-CIS Site by Site, e.g. current Retailer at Site, profile class, loss class, etc.
- Compare the cumulative energy consumption of each site in LPSS to the cumulative energy consumption recorded in ATCO-CIS.

The Supplier will automatically create a daily exception report that will be delivered to the Client for manual follow-up on items that do not balance.

The Supplier will identify system problems, i.e., to ATCO-CIS, LPSS or the interface and will advise the Clients and recommend solutions.

7.4. Daily Cumulative Meter Read (DCM) Files

The Supplier will use ATCO-CIS to create DCM files as per Service Policies.

The Supplier will send Daily Cumulative Meter (DCM) files to Retailers using DropChute as per Service Policies.

The Supplier will handle Retailer inquiries regarding DCM files and will investigate as per Service Policies.

Client to Provide...	Format	Timing
Policy on investigating load settlement files. D2-664	MS-Word	Before Service commencement

7.5. Daily Interval Meter (DIM) Files

The Client will manage all interval meter data.

The Client will publish interval meter in DIM format to Retailers using a secure data transfer protocol.

The Supplier will handle Retailer inquiries regarding missing DIM files and will investigate as per Service Policies.

Client to Provide...	Format	Timing
Policy on investigating load settlement files. D2-664	MS-Word	Before Service commencement

7.6. Daily Initial Load Settlement Data

The LPSS allocates usage by hour and produces daily load settlement data for usage four (4) days after the day of energy flow, e.g., allocate usage for Monday the 15th on Friday the 19th. The Supplier will send the data to the AESO and Retailers using DropChute.

The Client is responsible for data quality assurance.

The Supplier will investigate and resolve data problems and will manually re-schedule the required system processes as directed by the Client.

7.7. Daily, Monthly, Interim and Final Load Settlements

The Client, as the Load Settlement Agent, is responsible for producing daily and monthly interim and final settlement data as per Service Policies. The Supplier will use LPSS to produce the data according to Client's schedule. The Supplier will send the data to the AESO and Retailers using DropChute.

The Client is responsible for data quality assurance.

The Supplier will investigate and resolve data problems and will manually re-schedule the required system processes as directed by the Client.

7.8. Post-Final Adjustment Mechanism (PFAM) and Pre- Final Error Correction (PFEC)

The Supplier will notify the Client when requests that require investigation are received and will provide the Client with potential actions and an estimated cost to resolve the problem.

The Client will review the request and will direct the Supplier to take the appropriate action.

7.9. Load Settlement Data Inquiries

The Supplier will provide services as required to handle other load settlement data inquiries from Retailers, the Client, the AESO, Regulatory Agencies or other parties as directed by the Client.

Fee Schedule: Statement of Work

8. Financial Management

This Section describes how the Supplier will manage financial information for the Client, including:

- Balancing and Controls.
- Financial Reporting.
- Reporting to Third Parties.
- Administering External Business Accounts.

8.1. Balancing and Controls

General Information

The Supplier will manage financial information using generally accepted accounting principles. This includes reporting on revenue billed and collected

by category, reconciling variances between amounts billed and amounts paid, and making correcting entries as necessary.

On a daily and monthly basis, the following is balanced to control reports:

- Accounts Receivable.
- Revenue.
- Cash.
- Deposits.
- Deposit Interest Accrued.
- Write-offs.
- General Ledger interfaces.

On a monthly basis, an accounts receivable reconciliation of accumulated financial information is completed against the client's general ledger and journal vouchers are prepared for any reconciling items.

The following is balanced to the Oracle A/R General Ledger download:

- Accounts Receivable.
- Revenue.
- Cash.

On a yearly basis, the following is balanced to control reports:

- Deposit Interest Applied.

Client to Provide...	Format	Timing
Policy on how the Supplier will manage the timely and effective flow of accurate financial data to meet financial settlement and accounting needs pertaining directly to Accounts Receivable only. D2-935	MS-Word	

Balancing ATCO-CIS Accounts

Pursuant to Section 10.5 (Reports and Data Extracts), the Supplier produces the Supplier standard financial reports for each billing cycle or month including:

- Revenue generated by rate and use class.
- Fixed vs. variable charges.
- Payments by collection method (cash, bank transfer, etc.).

The Supplier does many daily balancing and control reconciliation activities including:

- Reconciling bank electronic funds transfer reports to ATCO-CIS.
- Preparing journal vouchers.
- Investigating all outages within the control worksheets pertaining to such items as accounts receivable, cash revenue, refunds, etc.
- Balancing daily cash control reports.
- Balancing receivables to daily activities.
- Tracking payments received by financial institution.
- Reconciling funds deposited in the Client's bank accounts with payment

sources and types.

- Reconciling deposits and deposit interest held and refunded.
- Reconciling information in different financial systems.

The Supplier will identify and investigate variances identified in controls.

The Supplier will provide balancing and control reports to the Client as specified in Section 10.5 (Reports and Data Extracts).

Additional reports can be provided to the Client pursuant to Section 10.5 (Reports and Data Extracts). **(optional)**

Fee Schedule: Statement of Work or Change of Service Request

Client to Provide...	Format	Timing
Reporting requirements including data required and frequency.	MS-Word	
Policy on how the Supplier will manage the timely and effective flow of accurate financial data to meet financial settlement and accounting needs pertaining directly to Accounts Receivable only. D2-935	MS-Word	

8.2. Financial Reporting

Pursuant to Section 10.5 (Reports and Data Extracts), the Supplier will provide the Client with the printed and electronic financial reports available at the time of signing and listed in Appendix B: Standard Reports.

The Supplier can customize these reports or develop new reports as requested by the Client, pursuant to Section 10.5 (Reports and Data Extracts) **(optional)**.

Fee Schedule: Statement of Work

Client to Provide...	Format	Timing
A list of the Supplier's standard reports desired including frequency, where applicable, format (electronic or print).	MS-Word	
A list of additional reports required including frequency, specific information required, sorting and subtotaling.		
Policy specifying retention period for various reports. D2-390		

8.3. Reporting to Third Parties (Optional)

The Supplier will provide data to regulatory agencies and other third parties as directed by the Client and in accordance with the Service Policies. The Supplier can invoice the third party on behalf of the Client using a Statement Account created in ATCO-CIS and payable to the Client.

Fee Schedule: Statement of Work (for special requests)

8.4. Administering External Business Accounts

The Supplier will manage accounts with external suppliers on behalf of the Client for suppliers that existed at the time of signing the Agreement, including:

- Collection agency.
- Suppliers of bill stock, envelopes, etc.
- Canada Post.
- Long distance or toll-free telephone access.

Fee Schedule: Pass-Through Charges

The Supplier can also manage accounts with additional suppliers. **(optional)**

Fee Schedule: Statement of Work

9. Consulting and Special Services

The Supplier can provide the following **optional** consulting Services to the Client at the Client's request.

9.1. Business Process and Policy Consulting (Optional)

The Supplier can analyze the Client's billing related business processes, policies and general consulting to improve operational efficiencies and better integrate them with the Supplier's Service offering. The Supplier has considerable experience in call centre operations, credit and collections, financial controls, bill design and deregulation issues.

This consultation can be provided on a one-time basis at the commencement of Services with the Supplier, or at any time and from time to time thereafter.

Fee Schedule: Statement of Work or Change of Service Request

9.2. Call Centre Script Development (Optional)

The Supplier will use scripts provided by the Client or can create them on the Client's behalf.

Fee Schedule: Statement of Work

9.3. Project Management (Optional)

The Supplier can manage projects on behalf of the Client. This work includes Systems development, marketing initiatives or Customer research.

Fee Schedule: Statement of Work

9.4. Access to ATCO-CIS

The Supplier will provide the Client with Access to ATCO-CIS in accordance with the Agreement.

Hardware and Infrastructure

The Client must use workstations and network infrastructure approved by the Supplier to Access ATCO-CIS.

Fee Schedule: Statement of Work

Availability

The Supplier's Systems and ATCO-CIS require upgrades, maintenance and data conversions and backups. This work may reduce the hours of operation and/or availability of System resources. The Supplier will use commercially reasonable efforts to schedule maintenance and data conversions outside of the Business Hours on Business Days.

Security

The Supplier will create and manage the appropriate security groups for the Client's Access to ATCO-CIS. The Client is responsible for determining requirements and for notifying the Supplier of changes to security (e.g., when new employees are hired or an employee no longer works for the Client).

The Supplier will provide the Client with reports that identify Client user groups and Access.

9.5. User Support

Documentation and Training

The Supplier will provide ATCO-CIS documentation and training Services to authorized Client representatives. Services to be provided from the Supplier's offices include:

- Needs analysis.
- Developing print or online documentation.
- Developing training materials.
- Training delivery.
- On the job coaching.

Some topics typically covered in training include:

- An introduction to utilities and basic billing concepts.
- ATCO-CIS concepts.
- Using ATCO-CIS (hands-on systems training).
- Business process and procedures training.

Fee Schedule: Statement of Work

The Supplier can also provide the Client with web-based resources for users, e.g., quick references and other online documentation, change notice archive, forms and other useful information.

Fee Schedule: Statement of Work

10. Administration

This Section describes the processes for how the Supplier and the Client work together, including:

- Office Locations and Hours of Operation.
- Holidays.
- Client Relationship Management.
- Escalation Process.
- System Parameters for ATCO-CIS.
- Reports and Data Extracts.

10.1. Office Locations and Hours of Operation

The Supplier can provide Services during other dates and times by developing a Statement of Work or a Change of Service Request.

All times are quoted in Mountain Standard Time (MST).

Customer Assistance Centre (CAC)

Hours of operation are 7:00 a.m. to 7:00 p.m., on Business Days. After hours calls receive a recorded message providing hours of operation and after hours contact information.

Other Work Areas

The hours of operation for all other work areas are 8 a.m. to 5 p.m., on Business Days.

10.2. Holidays

The Supplier does not operate or have billing cycles on the following Canadian holidays: New Years' Day, Alberta Family Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labor Day, Thanksgiving Day, Remembrance Day, Christmas Day, and Boxing Day.

10.3. Escalation Process

Prior to referring disputes to the Dispute Resolution process under Article 14 (Dispute Resolution) of the Agreement, the Supplier will work with the Client to identify, problem solve, and find resolution to business issues by following the escalation processes described in the Service Policies.

Client to Provide...	Format	Timing
Policy specifying escalation processes to be used for account-specific and contract-management related issues. D2-920	MS-Word	

10.4. System Parameters

The Supplier will manage Client specified parameters in ATCO-CIS to support Customer billing in a manner consistent with the Service Policies and business practices.

The Supplier will provide a list of parameters that are specified by the Client.

The Supplier will change Client specified parameters as requested by the Client. Some changes may require a Statement of Work or Change of Service Request (e.g. if the change is deemed by the Supplier, in its Discretion, to be complex or to significantly affect bill printing, System processing time, etc.). The Client must approve changes in writing before the changes will be implemented by the Supplier.

Fee Schedule: Statement of Work or Change of Service Request

Client to Provide...	Format	Timing
Specific values for each system parameter requested by the Supplier.	Supplier provided forms	Prior to Service commencement
Written notification to the Supplier whenever parameters need to change to reflect changes in Client's business policies and practices.	Supplier provided forms	Varies. Advance notice must allow time for determining affected parameters, proposing a solution, testing and Client sign-off.

10.5. Reports and Data Extracts

Standard, System Generated Reports

The Supplier will provide the Client with the pre-defined reports set forth in Appendix B (Standard Reports) with the frequency set forth therein.

Custom Reports (Optional)

The Supplier can provide the Client with reports that can be filtered and/or sorted based on user defined criteria. The Supplier can also provide the Client with additional reports on request.

The basic process for requesting a custom report is as follows:

- Client identifies report requirements in writing (purpose, data required, sorting and/or subtotaling, frequency, etc).
- The Supplier will provide a cost and time estimate.
- If the Client wishes to proceed, the Supplier provides a detailed design document and report mock-up, revising as necessary based on Client feedback.
- Client approves design.
- The Supplier constructs and tests report.
- Client receives report.

Fee Schedule: Statement of Work

Performance Measure/Service Level Reports

The Supplier will provide the Client with monthly reports regarding the Service Levels defined in Schedule B (Service Levels) of the Agreement.

Data Extracts

The Supplier will provide the Client with the ongoing data extracts routinely provided by the Supplier at the time of signing the Agreement. The extracts allow the Client to review data with minimal involvement from the Supplier. The Client is responsible for all systems and processes used to read and analyze the data.

Client to Provide...	Format	Timing
Data requirements and number of months' history required.	MS-Word	Before Service commencement

The Supplier can provide the Client with training on using the extract and technical assistance, if required **(optional)**.

Additional extracts, changes to the extract and assistance with using the extract can be provided on request **(optional)**.

Fee Schedule: Statement of Work

10.6. Retention of Information

The Supplier will maintain all documentation in either electronic or paper format as defined in the Service Policies.

Client to Provide...	Format	Timing
Policy that specifies information retention, archive and purge requirements. D2-390	MS-Word	

Appendix A: Client Deliverables

Policy References

D2-100: Policy on communications between Retailers, Distributor and Customers – 6, 7, 8, 9, 10, 11, 12, 14, 62

D2-105: Policy on managing inbound calls relating to the Motorist Observation Program(MOP)

D2-110: Policy on acceptable forms of communication – 6, 8, 9, 10, 11, 12, 13, 62

D2-115 : Policy on managing Retailer Requests for Replacement or Resending of Data Records

D2-120: Policy on the use of the telephone auto-attendant - 12

D2-142: Policies and procedures for after hours assistance- 17

D2-145: Policy on managing customer and account issues- 6, 24

D2-150: Policy on the use of communication records - 15

D2-155: Policy regarding the use of additional statement copies and memo statements – 32

D2-160: Policy that defines how the Supplier will manage returned mail

D2-180: Policy on the release of information to Retailers and Site Customers – 20, 21 62

D2-205: Policies on the use of web-based information to and from Retailers - 23

D2-235: Policy on Distributor invoicing methods

D2-240: Policy on billing options – 28, 32, 45, 66

D2-260: Policy on updating Site Contacts for retail Sites – 14, 29, 46

D2-261: Policy on following up on UCI transactions that do not match information in ATCO-CIS – 29, 46

D2-265: Policy on managing the Tariff Bill Calendar and Site-Cycle Catalogue

D2-270: Policy on the management of charge and statement cycles – 28, 30, 45

D2-271: Policy on off cycle statements – 30, 64, 65, 66, 67

D2-275: Policy on statement messaging

D2-280: Policy on the use of statement copies and memo statements – 32

D2-295: Policy on sending enrollment confirmation letters – 14, 34

D2-300: Policy on following up on specific and failed enrollments – 14, 34

D2-310: Policy on de-enrolling sites – 14, 35, 36

D2-315: Policy on enrollment errors – 36, 38

D2-322: Policy on managing financial responsibility for sites – 14, 34, 35, 36, 40

D2-325: Policy on processing requests for service connections and disconnections – 11, 12, 14, 34, 36, 43, 47

D2-327; Policy on managing Retailer requests to cancel a de-energize order

D2-330: Policy on applying or waiving contract penalties - 39

D2-347: Policy on creating Service Accounts for Distributor Site Customers are required - 37

D2-380: Policy on Work Requests – 10, 41, 42, 43

D2-390: Policy defining the requirements for retaining customer account information and reports – 44, 91

D2-421: Policy defining the Supplier role in creating new sites – 45, 46

D2-440: Policy on the use of system versus manually calculated annual usage - 46

D2-450: Policy on accepting meter reads from the Retailer, Site Customers or Site Contact – 14, 51, 54

D2-460: Policy on requesting and charging for off cycle reads – 14, 52

D2-470: Policy and parameters on read estimates – 52, 54

D2-480: Policy on when meter reads will be used for charging – 52, 54, 56

D2-500: Policy on following up on reads, usage and charges that fail validation – 56, 57, 60, 64, 65, 67

D2-510: Policy defining the defining when service fees are charged and/or waived – 10, 42, 58

D2-522: Policy on determining GST exemption status - 61

D2-523: Policy on the provision of reports to Retailers, Retail Site Customers and Site Contacts – 14, 62

D2-540: Policy on adjustments including approval levels, audit requirements, when researched or made – 60, 61, 64, 65, 67

D2-543: Policy on account investigation, e.g., who can authorize, actions to take, etc. – 58, 60, 64, 65, 67

D2-553: Policy on voiding statements – 31, 64, 65, 66, 67

D2-570: Policy on E-Bills eligibility and distribution methods – 60, 64, 65, 66, 67, 69

D2-575: Policy on managing Tariff Bill File transactions

D2-581: Policy on the use of return envelopes – 72

D2-582: Policy on managing Miscellaneous Invoicing-

D2-585: Policy on acceptable forms and methods of payment – 33, 74, 77

D2-594: Policy on using maximum PPP withdrawal limits – 33, 74, 77, 79

D2-612: Policy on notifying the Client of NSF withdrawals - 79

D2-620: Policy on refunding deposits and credit balances – 79, 80

D2-630: Policy on monitoring Retailers and Prudential Reporting

D2-640: Policy on acceptable form and level of security from Distributor Site Customers - 82

D2-650: Policy on when to undertake specific collection activities - 82

D2-660: Policy on write offs - 82

D2-663: Policy specifying when the Supplier can update information in the equipment subsystem – 85

D2-664: Policy relating to validating and managing load settlement and Data Cumulative Meter data – 14, 54, 56, 87, 88

D2-920: Policy on resolving Master Services Agreement Disputes Issue escalation process - 95

D2-921: Policy on approval of price/rate changes for both new and existing rates - 63

D2-925: Policy on managing threats against employees and facilities

D2-930: Policy on managing Independent Distributor Accounts

D2-935: Policy on managing the accounts receivable reconciliation

Non Policy References

Annual usage values 46

Applicable price schedules and distribution service fees for Enrollments.:

Approval of form letters and selection criteria – 20

Bill message and selection criteria - 19

Customer advisories and scripts - 24

Contract details whenever new contracts are negotiated or existing contracts are changed

Customer contract for Electronic Funds Transfers - 77

Data extract requirements - 97

Detailed business processes on how the Supplier, the Client and the Retailer work together - 23

Details of communications with Customers - 14

Financial reporting requirements – 90, 91

Retailer Guide requirements – 23

Retailer terms and conditions for distribution access- 22

Values for the ATCO-CIS parameters requested by the Supplier - 96

Written notification when ATCO-CIS parameters change - 96

Appendix B: Standard Reports

	ATCO Electric ATCO-CIS	Frequency of Report
REPORT NUMBER	REPORT NUMBER	
C202BRP1205	Equipment Items Within Equipment Group	Ad hoc
C202BRP1240	AMR Verifications Due	Monthly
C202BRP1245	AMR Verifications - Successful	Monthly
C202BRP1250	AMR Verifications - Unsuccessful	Daily
C202BRP1253	AMR Transmission Control Report	Ad hoc
C202BRP1254	AMR Quality Report	Daily
C202BRP1255	AMR Reading File Errors	Daily
C202BRP1259	AMR Verifications - Incomplete	Daily
C202BRP2001	Paper Meter Read Orders	Daily
C202BRP2105F	Charge Review Summary	Monthly
C202BRP2130	List of No Bills	Monthly
C202BRP2240	Monthly Statement Count	Monthly
C202BRP4201	Daily Unpaid REAL Fees	Daily
C202BRP4204	Monthly Paid REAL Fees	Daily
C202BRP4205A	REAL Arrears Report (Active Services)	Monthly
C202BRP4205B	REAL Arrears Report (Inactive Services)	Monthly
C202BRP4205C	REAL Arrears Report (Final Services)	Monthly
C202BRP4205D	Company Farm Arrears Report (Inactive Services)	Monthly
C202BRP4205E	Company Farm Arrears Report (Final Services)	Monthly
C202BRP4206	REAL Company Farm Service Point Counts	Monthly
C202BRP4210	REAL YTD Consumption & Revenue	Yearly – June
C202BRP4210A	Company Farm YTD Consumption & Revenue	Yearly - June
C202BRP4435	Critical Facility Report	Daily
C202BRP4460M	Enrollments by Retailer	Daily
C202BRP4490C	Default Supply/Last Resort Finals	Monthly
C202BRP9810	Electrical Distribution System - Overhead	August and October Cycle 20
C202BRP981U	Electrical Distribution System - Underground	August and October Cycle 20
C202BRP9820	Electrical Distribution System - Overhead	August and October Cycle 20

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REPORT NUMBER	ATCO Electric ATCO-CIS REPORT NUMBER	Frequency of Report
C202BRP982U	Electrical Distribution System - Underground	August and October Cycle 20
C202BRP998.1	Electrical Distribution System – Overhead and Underground	August and October Cycle 20
C202BRP998.1A	Electrical Distribution System – Overhead and Underground	August and October Cycle 20
C202BRP998.1O	Electrical Distribution System - Overhead	August and October Cycle 20
C202BRP998.1U	Electrical Distribution System - Underground	August and October Cycle 20
C202BRP998.2	Electrical Distribution System – Overhead and Underground	August and October Cycle 20
C202BRP998.2A	Electrical Distribution System – Overhead and Underground	August and October Cycle 20
C202BRP998.2O	Electrical Distribution System – Overhead	August and October Cycle 20
C202BRP998.2U	Electrical Distribution System - Underground	August and October Cycle 20
C202DFS2525G	Aged Accounts Receivable Summary - Rate Code within Status	
C202RP1165	Equipment Item Event Report	Monthly
C202RP1200	Equipment Item Order Control	Daily
C202DP2156	G/L Activity - Detail	Daily
C202DP2156B	G/L Activity – Summary	Daily
C202DP2156R	REA G/L Activity - Detail	Daily
C202DP2156RB	REA G/L Activity – Summary	Daily
C202DRP2122A	Revenue by Revenue Class	Daily
C202DRP2122B	Revenue by Revenue Class Summary	Daily
C202RP2122AD	Distribution Revenue by Revenue Class/Rate	Monthly
C202RP2122AE	Regulated Revenue By Revenue Class/Rate	Monthly
C202RP2122AM	Company Revenue by Revenue Class/Rate	Monthly
C202RP2122AS	Default Supply Revenue by Revenue Class/Rate	Monthly
C202RP2122AT	Transmission Revenue by Revenue Class/Rate	Monthly
C202RP2122AV	Service Revenue by Revenue Class/Rate	Monthly
C202RP2122BD	Distribution Revenue by Rate	Monthly

REPORT NUMBER	ATCO Electric ATCO-CIS REPORT NUMBER	Frequency of Report
C202RP2122BE	Regulated Revenue By Rate	Monthly
C202RP2122BM	Company Revenue by Rate	Monthly
C202RP2122BS	Default Supply Revenue by Rate	Monthly
C202RP2122BT	Transmission Revenue by Rate	Monthly
C202RP2122BV	Service Revenue by Rate	Monthly
C202DRP2517	Manual Journal Summary	Daily
C202MRP2123B	Monthly Revenue by Division	Monthly
C202MRP2123C	Monthly Revenue by District	Monthly
C202MRP2123H	Monthly Energy Sales Stats by SIC/Rate	Monthly
C202MRP2123I	Monthly Energy Sales Stats by SIC	Monthly
C202MRP2124	Summary of Revenue - Isolated Communities by rate/plant	Monthly
C202MRP2124B	Summary of Revenue – Isolated Communities by rate class	Monthly
C202BRPLPSSB	LPSS Reports – Meter Read Statistics	Ad hoc
C202BRPLPSSC	LSA Data Quality Reports Summary	Ad hoc
C202BRPLPSSE	DSM Release Report 1 – 3	Ad hoc
C202BRPLPSSF	LPSS Reports – Meter Read Statistics	Ad hoc
C202BRP1102	Government Test Group Recall Report	Daily
C202BRP2010	Street and Outdoor Light Audit	Ad hoc
C202BRP4410	DCM File Errors	Daily
C202BRP4420A	LPSS Reports	Daily
C202BRP4421	DIM Status Report	Daily
C202BRP4421A	Transmission and Primary Distribution Connected Sites	Daily
C202MRP2151D	Sales Tax Report by Community	Monthly
C202MRP2898	Generation Sites Customer Information Change Report	Monthly
C202MRP3150	Rate Expert Charge Data Interface	Monthly
C202MTRCRD	Meter Cards	Daily
C202RP1107	Meter Re-verification Update Report	Daily
C202R1100	Meter Purchase Transaction Report	Daily
C202R1101	Meter Purchase Exception Report	Daily
C202R4425	Service Points With No Built Date	Weekly
C202SUM2525G	Aged Accounts Receivable Summary	Monthly
C202RP1640	Critical Use Sites	Monthly to each

REPORT NUMBER	ATCO Electric ATCO-CIS REPORT NUMBER	Frequency of Report
		District office
C202RP1345	Customer Inventory	Monthly
C202RP1214	NEWCIS Unmetered Accounts - Rate Class 1,2,5,8	Monthly
C202DRP4731	Tariff Bill Performance Reporting - Metric 1	Daily
C202DRP4732	Tariff Bill Performance Reporting - Metric 2	Daily

CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Effective January 1, 2010

SCHEDULE B
SERVICE LEVELS

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ATCO ELECTRIC SERVICE LEVELS

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1. Introduction

This is Schedule B to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. (the "**Supplier**") and ATCO Electric Ltd. (the "**Client**").

1.1 Purpose of This Document

This Schedule describes the Supplier's Service Levels for delivery of the Services to the Client. It also describes the performance measures that will be reported by the Supplier.

1.2 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Customer**" has the meaning described in Schedule A (Definition of Services) of the Agreement.

"**Customer Assistance Centre**" or "**CAC**" has the meaning described in Schedule A (Definition of Services) of the Agreement.

"**Customer Assistance Centre Representative**" or "**CACR**" means the Supplier's Representatives who are responsible for inbound and outbound customer phone calls in respect of the CAC.

"**Day**" means the end of the following Business Day.

1.3 Statement of Intent

The Service Levels are measurements that the Client and the Supplier have agreed to use as a basis for determining contractual requirements as specified in the Agreement or in other Schedules of the Agreement.

Service Levels and measurement methods have been agreed to between the Client and the Supplier and may be changed from time to time pursuant to a Change Request. The purpose of Service Levels is to monitor performance of the Services by the Supplier.

1.4 Scope of This Document

This Schedule identifies specific Service Levels with measurable performance commitments for each as well as "reporting only" requirements. This Schedule also identifies specific assumptions on which the performance commitments and reporting requirements are based.

These commitments are described as shown below.

Service Level Measurement Number /Name: The name and number of the Service Level item.

Indicator Type (CPI, KPI or GPI): Identifies the relative importance of a Service Level and whether Service Credits are applicable if the Minimum Service Level has not been achieved.

Measurement Window: This determines the time period for the measurement of the Service Level (e.g. daily, monthly, quarterly).

Measurement Tools: This identifies the tools used by the Supplier for monitoring and collecting of performance data.

Target: Mutually agreed upon expected level of Service performance for the metric.

Minimum: Mutually agreed upon minimum level of Service performance. Not achieving this level will invoke a Service Credit or root cause analysis with written plan for improvement.

Description/Measurement: A brief description of the Service Level metric and how the measurement data is to be used and the parameters of the formula.

Calculation Definition: Actual calculation, detailing the factors and how the average over the measurement window is determined.

1.5 Key Service Delivery Areas

The Supplier provides Services to the Client in the following areas:

(a) Relationship Management: Services directly related to the operation of:

- the distribution Customer Assistance Centre, including the delivery of Customer Services.

(b) Account and Revenue Management: Services related to:

- the exchange of data between the Client and Retailers,
- managing Customer accounts and related charges, primarily the calculation of distribution charges and forwarding them to Retailers,
- development and management of Field Orders,
- load settlement.

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(c) Receivables Management: handling remittance processing items by type and entity.

(d) Financial Management: balancing and controls of internal accounts and Services, and handling posting the financial data in Client financial reporting tools.

1.6 General Assumptions

The Service Levels in this Schedule were developed mutually by both the Client and the Supplier based upon historic volumes. Any material changes in volumes created by the Client or changes to Service Levels must be agreed upon by the Supplier and the Client pursuant to a Change Request.

The Service Levels described herein are based on the assumption that the general business practices, regulations and policies related to electricity in Alberta will be consistent with those in effect as of the date of this Agreement for the electricity industry in the Province of Alberta. If these assumptions change during the course of this Agreement then a Change Request will be required.

If actual volumes deviate by 10% or more from mutually agreed upon volumes, then the Supplier shall be relieved from attaining the Service Levels in the applicable section until such time as the actual volumes return to the agreed upon volume levels, or until such time as a Change Request is prepared and the Supplier is able to adjust its resources to meet the change in volumes.

Should a new Service Level be added, the first three (3) months will constitute an acceptance period and minimum and target Service Levels will not apply.

The Supplier's obligation to meet the Service Levels in this Schedule (including its obligations pursuant to Section 1.7 (Service Level Reporting)) and the Agreement are also subject to the assumptions listed in the specific sections of this Schedule, and in the Agreement, including sections 2.1(a) (Services) and 6.6 (Workload Planning).

1.7 Service Level Reporting

On or before the fifteenth (15^{th}) Business Day of each month, the Supplier shall provide to the Client a written report setting forth the actual Service Levels achieved in the previous month. Additional reporting will be provided for any Service Level that meet the criteria as outlined in Section 2.7 (Service Level Methodology and Performance Indicators) of the Agreement.

1.8 Reporting Requirements

The Supplier's reporting requirements are listed in this document. The Client may request additional reporting on the Supplier's performance of the Services. The Client will meet with the Supplier to determine the feasibility of new report(s) and to evaluate whether new report(s) can be implemented within the scope of the existing Agreement or whether a Change Request is required.

2. Customer Relationship Management

2.1 Overview

This Section outlines Service Levels and reporting requirements for Services related to customer relationship management including the CAC operations and Customer satisfaction indicators.

2.2 Assumptions

2.2.1 The Supplier's obligation to attain the Relationship Management Service Levels and reporting outlined herein, is subject to the following assumptions:

The Supplier will utilize telephony technology to aid in directing all callers to the appropriate queue within CAC. Multiple layers or subdirectories are not available and the current technology does not have interactive voice response capabilities, has limitations as to the number of ports available and the number of menu options is limited to 9.

2.2.2 The following sections describe the process for handling calls, and for measuring the Supplier's call handling performance. These measurements are used as the basis for the Service Levels and reporting requirements that follow.

Measuring Call Statistics

Typical Call Handling (not to scale)

1: Call Initiated by Customer Dialing Distribution Phone Number
2: Call Answered by the Auto Attendant System (if applicable)
3: Call Routed to Appropriate Skill Set after Customer makes Choice(s)
4: CACR Answers Call
5: CACR Places Customer on Hold while Processing/Researching (if required)
6: CACR Resumes Conversation with Customer
7: CACR/Customer Hangs up
8: CACR Available to take next Call

A: Call rings before being answered by the Auto Attendant. Time/rings varies with call volume and Auto Attendant capacity
B: Customer listens to Auto Attendant messages. Time varies with message length and choices made by Customer.
C: Call is waiting in the appropriate Skill Set until a CACR is available to take the call. Time varies with call volumes and CACR availability.
D: CACR and Customer are speaking. Time varies with complexity of call.
E: Customer is waiting on hold while the CACR researches the call, checks with team lead, etc.
Time varies with complexity of call. (If required)

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F: CACR does additional online or manual processing after disconnecting from the Customer. (If required) CACR is not available for another call during this time. Time varies with complexity of the follow-up required.

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CPIs and KPIs for Customer Relationship Management

CPIs and KPIs for Customer Relationship Management Service Level Measurement No.	Service Level Measurement Name	Indicator Type	Measurement Window	Measurement Tool	Target	Minimum	Description/ Measurement	Calculation Definition
CRM 1	Service Level for calls answered	CPI	Monthly	ACD	80%/20 seconds	70%/20 seconds	% of calls answered within specified time	SL= ((Total Calls Answered – Calls Answered After Threshold) / Total Calls Answered) x 100
CRM 2	Abandoned Calls	CPI	Monthly	ACD	<5%	<6%	% of total calls that were in the queue six seconds or longer and were abandoned	SL = ((Calls Abandoned – Calls Abandoned < 6 secs) / Calls Offered) x 100
CRM 3	Customer Satisfaction	CPI	Annual	Customer Satisfaction Survey	85%	76.5%	Satisfaction level based on an annual survey of Site contacts by a third party contracted by the Supplier to measure courtesy, satisfaction, CACR knowledge and issue resolution	*Calculation is derived from customer responses to the following question: "Based on your last call to the call centre, overall how satisfied are you with ATCO Call Centre?* Very Satisfied Somewhat Satisfied Somewhat Dissatisfied or, Very Dissatisfied Don't Know

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GPIs for Customer Relationship Management

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
CRM 4	Calls Answered	Daily/Monthly	ACD	Total number of inbound calls answered by CACR's	Total number of inbound calls answered by CACR's
CRM 5	Inquiries from Retailers	Monthly		Total number of inquiries from Retailers, categorized by Retailer, reason for inquiry and type of inquiry	Total number of inquiries from Retailers, categorized by Retailer, reason for inquiry and type of inquiry
CRM 6	Handle Time	Monthly	ACD	Average time to handle customer inquiry	SL= Talk Time + Post Call Processing / Total Calls Answered
CRM 7	Number of calls handled and had first call resolution	Monthly		Inbound calls handled by agent and met customer needs in the first contact	SL= Total Calls Answered - Repeat Calls (calls from the same person about the same matter)
CRM 8	Escalated Calls	Monthly		Number of calls to a higher level when CACR could not resolve	ATCO-CIS Report RP1401 Communication Event Statistics

3. Account and Revenue Management

3.1 Overview

This section outlines Service Levels and reporting requirements for Services related to managing Sites and Service Accounts, including:

- Enrolling and De-Enrolling Sites,
- The receipt of metering information from the Client,
- Exchanging data with Retailers,
- Managing Service Orders,
- Customer Billing.

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3.2 Enrollment/De-Enrollment

Assumptions

The Supplier's obligation to attain the data exchange Service Levels and reporting outlined herein is subject to the following assumptions:

(a) The Supplier will send and receive electronic transactions to and from Retailers as required by Alberta regulations that are in effect at the time of signing this Agreement.

(b) The maximum number of Enrollments received per day is 3,500 and per month is 71,500.

(c) The maximum number of De-Enrollments received per day is 600 and per month is 1,200.

CPI and KPIs for Account and Revenue Management

Service Level Measurement No.	Service Level Measurement Name	Indicator Type	Measurement Window	Measurement Tool	Target	Minimum	Description/ Measurement	Calculation Definition
ARM 1	Successful Enrollments	CPI	Monthly	ATCO-CIS Report RP4620B Distribution Enrollments (monthly)	99%	90%	Percent of Enrollments successfully processed as required by regulations,.	SL = # of Enrollments Processed / # of Enrollments Received
ARM 2	Successful De-enrollments	CPI	Monthly	ATCO-CIS Report RP4625B Distribution De-Enrollments (monthly)	99%	90%	Percent of DE-enrollments successfully processed as required by regulations,	SL = Total Successful De-enrollment Notifications / Total De-enrollment Requests x 100
ARM 3	Enrollment Confirmation or Notification	KPI	Monthly	ATCO-CIS Report RP4620B Distribution Enrollments	99%	90%	Enrollment confirmation or failure notification sent to Retailer as required by Regulations	SL = Total Select Retailer Notifications sent within one day / Total Number of Enrollments processed x 100 (monthly)

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GPIs for Account and Revenue Management

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
ARM 4	Successful Enrollments	Monthly	ATCO-CIS Report RP4620B Distribution Enrollments (monthly) – validate manual counts from Drop Chute backup files.	Number of enrollment requests successfully received, subtotaled by Retailer	Drop Chute Backup Files - Industry Dialogue Manager (IDM) retrieves the daily number of Select Retailer Request (SRR) files from drop chute back-ups.
ARM 5	Enrollments Rejected	Monthly	ATCO-CIS Report RP4620B Distribution Enrollments (monthly) – validate manual counts from Drop Chute backup files.	Number of enrollments rejected, subtotaled by Retailer	Drop Chute Backup Files - Industry Dialogue Manager (IDM) retrieves the daily number of Select Retailer Notification (SRN) files from drop chute back-ups.
ARM 6	Successful De-enrollments	Monthly	ATCO-CIS Report RP4625B Distribution De-Enrollments (monthly) – validate manual counts from Drop Chute backup files.	Number of successful De-enrollment requests received, subtotaled by Retailer	Drop Chute Backup Files - Industry Dialogue Manager (IDM) retrieves the daily number of successful De-Enrollment Requests (DSR) files from drop chute back-ups.
ARM 7	De-enrollment confirmations	Monthly	ATCO-CIS Report RP4625B Distribution De-Enrollments (monthly) – validate manual counts from Drop Chute backup files.	Number of De-enrollment confirmations or failure notification sent to Retailer as required by Regulations	Drop Chute Backup Files - Industry Dialogue Manager (IDM) retrieves the daily number of successful De-Enrollment Notifications (DSN) files from drop chute back-ups.
ARM 8	Usage Transactions	Monthly	ATCO-CIS Report RP4635B Distribution Load Settlement DCM Usage (monthly) - validate manual counts from DCM	Number of usage (DCM) transactions sent to Retailers	ATCO-CIS Daily Cumulative Meter (DCM) Consumption file

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			Consumption files.		
ARM 9	Failed Service Accounts	Monthly	ATCO-CIS Report RP4740 Tariff Bill Performance Reporting	Number of service accounts that were scheduled to be sent, but failed to statement	ATCO-CIS Report RP4740 Tariff Bill Performance Reporting

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3.3 Service Orders and Forms

Assumptions

The Supplier's obligation to attain the Service Levels and reporting requirements outlined herein is subject to the following assumption:

(a) The number of Service Orders created by the Supplier will not exceed 360 per day and 7,200 per month.

GPIs for Service Orders

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
SO 1	Number of orders created	Monthly	ATCO-CIS Monthly Data Extract File C202K072	Number of service orders created per month	Number of service orders created per month
SO 2	Number of orders completed	Monthly	ATCO-CIS Monthly Data Extract File C202K072	Number of service orders completed per month	ATCO-CIS Monthly Data Extract File C202K072
SO3	Percentage of service orders entered within one day from receipt of information	Monthly	ATCO-CIS Monthly Data Extract File C202K072	Percentage of service orders entered into ATCO CIS within one (1) day of receipt of complete and accurate information by major category	SL = # of service orders entered into ATCO CIS within one (1) day of receipt of complete and accurate information / total # of service orders received
SO4	Percentage of service orders entered within two days from receipt of information	Monthly	ATCO-CIS Monthly Data Extract File C202K072	Percentage of service orders entered into ATCO CIS within two (2) days of receipt of complete and accurate information by major category	SL = # of service orders entered into ATCO CIS within two (2) days of receipt of complete and accurate information / total # of service orders received

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3.4 Billing

Assumptions

The Supplier's obligation to attain the billing Service Levels and reporting outlined herein is subject to the following assumptions:

(a) The Supplier will generate bills based on available data in ATCO-CIS including meter reads, usage, estimates, distribution tariffs or any other data the Supplier receives from the Client.

(b) The number of items that fail charge validation and agreed upon usage validation will not exceed 150 per day and 3,000 per month.

(c) The number of cycles processed on any of the Supplier's 20 available cycles does not exceed two, for example, the Service Levels are valid if the Client chooses to process cycles 1 and 2 on cycle 2 but not if the Client chooses to process cycles 1, 2 and 3 on cycle 3,

(d) The Client will use reasonable efforts to distribute Service Accounts relatively evenly over the 20 available cycles.

(e) Bill 2 Assumptions:

(i) Multiple issues on one Service Account would be counted as one error.

(ii) If an error is determined in the current month but found to have occurred in previous periods the previous periods will not be recalculated and the previous months will not be considered when determining any Service Credits.

(iii) Only the current month information will be used in calculating Billing Accuracy Service Level.

(iv) Missing charges on a Service Accounts will be considered an error.

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CPI and KPIs for Billing

Service Level Measurement No.	Service Level Measurement Name	Indicator Type	Measurement Window	Measurement Tool	Target	Minimum	Description/ Measurement	Calculation Definition
Bill 1	Tariff Bill File	CPI	Monthly	Report using "RP4732 Tariff Bill Performance Reporting – Metric 12 Missing On-Cycle Sites" as the base.	99%	90%	Percent of all sites assigned to billing cycles transmitted on their published date as define in Tariff Bill Code within the Suppliers control	SL = # of sites assigned to billing cycle transmitted on their published as defined in the Tariff Bill Code (within Suppliers control) / total # of sites available for assignment
Bill 2	Billing Accuracy	CPI	Monthly		99%	90%	Percent of all SA sent to either Supplier Dropchute or Canada Post that are deemed to be accurate.	SL = (Total Number of Service accounts – (Total Number of Adjustments Within Suppliers Control)/ Total Number of Service Accounts) x 100
Bill 3	Reads	KPI	Monthly	ATCO-CIS Report RP4630A KPI/SLA Reporting Charges Calculated & Applied	99%	90%	**D2-SL40** Calculate usage and distribution charges based on the available valid reads within 2 charge cycles of the scheduled cycle, excluding factors outside of Supplier's control.	SL=((Number of Accounts Successfully Charged + Number of Failed Accounts (Within Supplier's Control) Successfully Charged Within 2 Cycles) / (Number of Accounts Scheduled to Charge – Number of Accounts that Failed Charge NOT Within Supplier's

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								Control))x100
Bill 4	Usage	KPI	Monthly		99%	90%	Send usage in DCM transaction to Retailers within two Days after usage has passed validation	SL= Total number of DCM's sent within 2 days /Total number of DCM Transactions to be sent X 100

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GPIs for Billing

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
Billing 5	Estimated Service Accounts	Monthly	ATCO-CIS Monthly Data Extract File C202K072	Number of service accounts that were estimated in the month	ATCO-CIS Monthly Data Extract File C202K072
Billing 6	Statement Accounts Billed	Monthly	ATCO-CIS Report RP2135A Statement Accounts To Statement	Number of statement accounts billed(calculated, printed or file generated and sent)	SL= Total Statements – Invalid Statements
Bill 7	Failed Charge Validation	Monthly		Number of items that failed Charge Validation	NA
Bill 8	Retailer Activity	Monthly		Number of billing inquiries by Retailer to Distributor	NA

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4. Receivables Management

4.1 Overview

This section outlines Service Levels and reporting requirements for Services related to managing receivables and remittance processing.

4.2 Remittance Processing

Assumptions

The Supplier's obligation to attain remittance processing Service Levels outlined in this section is subject to the following assumption:

(a) The Supplier will process all financial transactions to the Client's bank account with the Bank of Montreal.

CPI and KPIs for Remittance Processing

Service Level Measurement No.	Service Level Measurement Name	Indicator Type	Measurement Window	Measurement Tool	Target	Minimum	Description/ Measurement	Calculation Definition
REP 1	Payments Posted	CPI	Monthly	ATCO-CIS Report RP026 FIS Payments Control Report (extracts data from the cash database which includes all payments made to ATCO-CIS, NGSIS, or Oracle General Ledgers)	99%	90%	Payments posted to the Retailer or Distributor Site Customer Account on same business day before 4PM, only if Retailer provides correct and complete information	SL = (Number of Electronic Funds Transfer Payments Processed by 4 PM / Total Electronic Funds Transfers Received by 4 PM) x100

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GPIs for Remittance Processing

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
REP 2	Payments	Monthly	ATCO-CIS Report RP026 FIS	Number of payments received	Payments Control Report (extracts data from the cash database which includes all payments made to ATCO-CIS, NGSIS, or Oracle General Ledgers)
REP 3	Value of Payments	Monthly	ATCO-CIS Report RP026 FIS Payments Control Report (extracts data from the cash database which includes all payments made to ATCO-CIS, NGSIS, or Oracle General Ledgers)	Dollar value of payments	SL = $ Amount of Payments Deposited into Clients Bank Account Same Day + $ Amount of Payments Deposited into Clients Bank Account Within 1 Day + $ Amount of Payments Deposited into Clients Bank Account Within 2 Days
REP 4	Payments Received	Monthly		Number of payments received for processing	NA

5. Financial Management

Overview

This section outlines Service Levels and reporting requirements for Services related to financial management Services.

Assumptions

The Supplier's obligation to attain the Service Levels and reporting requirements outlined in this section is subject to the following assumption:

(a) The Client will provide, on the date(s) requested by the Supplier, the necessary information, Systems, approvals or other Client tasks required for the Supplier to complete the reconciliation in the agreed upon timeframes.

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CPI and KPIs for Financial Management

Service Level Measurement No.	Service Level Measurement Name	Indicator Type	Measurement Window	Measurement Tool	Target	Minimum	Description/ Measurement	Calculation Definition
FIM 1	Journal Vouchers	KPI	Monthly		99%	90%	Completed and submitted to the general ledger within two business days after receipt of accurate month end financial control reports	NA

GPIs for Remittance Processing

Service Level Measurement No.	Service Level Measurement Name	Measurement Window	Measurement Tool	Description/ Measurement	Calculation Definition
FIM 2	Accounts Receivable Reconciliation Monthly	Monthly		Monthly reconciliations completed and reconciled to the Clients general ledger, including identifying outstanding items for the prior month by the 25th day of the current period, excluding factors outside the Supplier's control	NA
FIM 3	Accounts Receivable Reconciliation Year end	Annually		Monthly reconciliations completed and reconciled to the Clients general ledger, including identifying outstanding items for the prior month by the 15th day of the current period, excluding factors outside the Supplier's control	NA

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CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Effective January 1, 2010

Schedule C

Fee Schedule

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ATCO ELECTRIC FEE SCHEDULE

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1. Introduction

This is Schedule C to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. (the "**Supplier**") and ATCO Electric Ltd. (the "**Client**").

1.1 Pricing Approach

The purpose of this Schedule is to provide a rate per unit, or bundled price, for the Core Services provided by the Supplier to the Client. In cases where the Client is responsible for payment and/or reimbursement of third party charges, the fee is described as a "Pass-Through Charge". Examples of Pass-Though Charges include postage, long distance telephone charges, credit card merchant fees, paper and envelopes.

1.2 Assumptions

The Service Account Volume range for the major pricing category provides for usage flexibility. The base Fees are based on the volume of usage indicated in the Service Account Volume range and will be applicable for the Term subject to Section 8.3 (Fees and Adjustments for Inflation) of the Agreement.

This Schedule is applicable for Services provided by the Supplier to the Client for Site Customers located in the Province of Alberta or Site Customers who are within a service territory, served by the Client in British Columbia and Saskatchewan, at the Service Date.

The Fees herein were negotiated and agreed to based upon the Supplier providing similar services to both ATCO Gas and the Client and therefore the Aggregate Volume.

The Fees herein are subject to the assumption that all Services are provided for the Client as one company or reporting entity. A Statement of Work will be required should the Client desire to have Services or Customers split in separate legal or reporting entities.

1.3 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Core Application**" means the ATCO-CIS core application which provides meter to cash business functions for standard gas and electric utilities operating in

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North America. The functionality includes customer account and service point information, pricing, usage measurements, charging, equipment inventory, service requests, revenue controls and balancing, payment processing, receivable and collection management;

"**Extended Application**" means the extended application functionality of ATCO-CIS and includes regulatory or company specific extensions and interfaces. Such extended application includes the functionality to meet the company specific requirements and interfaces and regulatory requirements such as Settlement System Code and Tariff Billing Code;

"**Inquiry/Inquiries**" means both inbound and outbound phone calls, faxes, e-mails, letters or other non-walk-in contacts with a Customer;

"**Monthly Base Fee**" means the Fees charged for the services provided by the Supplier as Core Services as described in Schedule A (Definition of Services) of the Agreement;

"**Non-Metered Service Account**" means an active Service Account for gas lights as entered into ATCO-CIS;

"**Service Account**" or "**SA**" means a billing entity associated with a Site that is established for charging;

"**Service Account Volume**" means the total volume of Service Accounts for which billing activity occurs for all billing cycles throughout a month; and

"**Tariff Bill File**" or "**TBF**" means a physical electronic file containing site-specific tariff charges, usage, and demand information for given tariff bill periods; it may also contain applicable site-specific one-time charges.

2. Fee Schedule (Electric)

The Client shall pay the Supplier the following rates for Services:

Fee Schedule	Unit Rate	Service Account Description	Service Account Volume Range
Core Services			
Monthly Base Fee (Metered)	$2.09	Per SA per Month	210,000-250,000
Monthly Base Fee (Non-Metered)	$0.90	Per SA per Month	40,000-55,000
ATCO-CIS Core Application Maintenance Fee			
Fixed Monthly Fee	$15,020.00	Per Month	

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Time and Material Rates (2010 unadjusted)

Labour Component 100%

Service Description	2010 – 2015 Pricing						
	Billing Metric	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Senior Billing Specialist	Per Hour	$109.00	$108.07	$107.15	$106.24	$105.34	$104.44
Billing/ Training	Per Hour	$70.00	$69.41	$68.82	$68.24	$67.66	$67.08
Customer Assistance Service	Per Hour	$43.60	$43.23	$42.86	$42.50	$42.14	$41.78
Administrator	Per Hour	$66.00	$65.44	$64.88	$64.33	$63.78	$63.24
Analyst 1	Per Hour	$90.00	$89.24	$88.48	$87.73	$86.98	$86.24
Analyst 2	Per Hour	$111.00	$110.06	$109.12	$108.19	$107.27	$106.36
Analyst 3	Per Hour	$137.00	$135.84	$134.69	$133.55	$132.41	$131.28
Analyst 4	Per Hour	$152.00	$150.71	$149.43	$148.16	$146.90	$145.65
Consultant	Per Hour	$198.00	$196.32	$194.65	$193.00	$191.36	$189.73
Senior Consultant	Per Hour	$264.00	$261.76	$259.54	$257.33	$255.14	$252.97
Project Manager	Per Hour	$204.00	$202.27	$200.55	$198.85	$197.16	$195.48
Senior Engagement Manager	Per Hour	$293.00	$290.51	$288.04	$285.59	$283.16	$280.75
Test Environment Charge [(1)]	Per CPU Minute	$5.77	$5.65	$5.53	$5.41	$5.30	$5.19

Note:
(1) Rate does not include labour component. Will be adjusted to include applicable labour component based on the provisions of the Agreement.

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Pass Through Charges

Pass Through Charges are all charges identified as Pass Through Charges in accordance with Section 6 (Pass Through Charges) of this Schedule including the following:

Postage, Envelopes, Paper

Long Distance Phone Charges

Collection Agency Fees

Courier Charges

Off-Site Data Storage

Third Party Wind Down Charges

Fee Charged Pass Through

3. Core Services

3.1 Monthly Base Fee

The Monthly Base Fee is the fee charged by the Supplier, per Service Account, for the provision of those Services referenced throughout Schedule A (Definition of Services) of the Agreement and for those services noted below. The Fees for Core Services apply to the Service Account Volume range and may be adjusted through the Change Request process if the volumes are outside of that range for more than four consecutive months

3.1.1 Labour

- The Supplier will provide labour for the Core Services specified in Schedule A (Definition of Services), in the manner provided and subject to the Service Policies in place as at the Service Date.

3.1.2 Processing Included

The Core Services Fee includes System (mainframe) batch and online processing related to:

- Normal, on-cycle processing of each Service Account, as required to calculate and create a bill for each Service Account on the scheduled monthly billing cycle

- Standard online processing by Supplier staff as required to provide the base billing services, e.g., searching, updating names and phone numbers, basic quality assurance, etc.

- Receiving, validating and applying meter reads to accounts

- Charge calculations and validations

- Calculating service charges

- Processing related to formatting and sending E bills

- Receipt and posting of payments

- Pre-defined ATCO-CIS standard format and content account-related batch reports and interfaces

- Supplier standard interfaces with standard Client Systems including, meter reading, dispatch/Service Orders and financial information Systems

- Supplier standard format and content files used to manage accounts in the Alberta deregulated marketplace, e.g., Enrollments, meter read requests, connection requests, etc.

- Sending and receiving account-related information through Supplier standard interfaces with third parties, e.g., banks

- Sending and receiving daily Tariff Bill Files from Retailers

3.1.3 ATCO-CIS Extended Application Maintenance

The Supplier will provide 13,500 hours of labour (ATCO Utilities combined) required for Extended Application and interface break-fixes, along with all labour required for integration management and acceptance testing to manage and optimize the production application as follows:

- Apply the extension and interface software to the Core Application upgrades

- Fixing of Extended Application and interface production problems or failure for daily operations and regular scheduled batch jobs

- Developing Extended Application or interface program fixes

- Analysis of Extended Application or interface problems and issues
- Provision of development and test environments for Extended Application break-fixes
- Provision of development and testing tools for Extended Application break-fix
- Selecting or creating test data for fixes
- Creating test scenarios for testing the fixes
- Cloning or refreshing test data to development or test environments
- Conducting unit and system testing and verifying results
- Maintaining the Extended Application configuration and supporting application development tools for the break-fix development and test environments
- Managing version control for the Extended Application and interfaces
- Maintaining Extended Application break fix issue logging and resolution
- On-going training of staff to support the Extended Application and databases
- Provision of facilities including office space, meeting rooms, video conferencing, desktop PC, monitor, telephone, printers, faxes and administrative support for production application support and break-fix personnel
- Documentation and performing annual disaster recovery testing

Integration Management and Acceptance Testing

- Database Management:
    - Monitor and maintain database performance
    - Perform back up and operational recoveries
    - Monitor and resolve database contention
    - Provision of database on-call support
    - Monitor and tune database performance

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- Monitor and maintain security framework
- Manage database space and partitioning
- Manage security framework
- Manage purge and archive procedures

- Release Management:
  - Provision of user acceptance testing environment for enhancement releases
  - Provision of testing tools for enhancement releases
  - Clone or refresh production or test data to user acceptance testing environment for enhancement releases
  - Manage the test application configuration and database for enhancement releases
  - Maintain application job schedules
  - Provision of production on-call support
- User Acceptance Testing:
  - Provision of user acceptance testing environment
  - Provision of testing tools
  - Provision of test environment on-call support
  - Select and /or create test data
  - Create test scripts
  - Clone or refresh production or test data for user acceptance testing
  - Conduct user acceptance testing and verify results
  - Conduct integration and regression testing and verify results
  - Maintain test application configuration and databases
- Disaster Recovery Testing:
  - Develop and maintain disaster recovery procedures and testing

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- Conduct disaster recovery tests, post disaster recovery review and maintain the disaster recovery plan

The Supplier will provide Client with a monthly report detailing both the current month and cumulative hours expended. If the hours required to perform the services described above exceed the 13,500 hours provided in the Core Service fee, the Supplier will notify the Client as to the reason. Any additional hours approved will be charged at the Time and Material Rates.

3.2 SOWs Included in Core Services

The following SOWs which had previously been invoiced separately have now been incorporated into the Core Services Fee:

- PB0022 – Delivery of Daily Telephone Statistics
- PD00341 – Refund Cheques
- PD00448 – Price Variance Reports
- PD00732 – Auto Attend Stats
- PD00759 – IPSOS Transaction Survey
- PD00933 – IDM Access
- PD00968 – Additional CPU – TBC Changes

All other SOWs will continue to be charged as indicated on the individual SOWs.

4. ATCO-CIS Core Application Maintenance Fee

The Supplier will provide all labour and test environment required for Core Application Break-Fix as follows:

- Fixing of Core Application production problems or failure for daily operations and regular scheduled batch jobs
- Software issue logging and resolution
- Developing Core Application program fixes
- Analysis of Core Application problems and issues
- Provision of development and test environments for Core Application break-fixes

- Provision of development and testing tools for Core Application break-fixes
- Selecting or creating test data for fixes
- Creating test scenarios for testing the fixes
- Cloning or refreshing production test data to development or test environments
- Conducting unit and system testing and verifying results within the ATCO-CIS application
- Maintaining the configuration and supporting application development tools for the break-fix development and test environments
- Managing version control for the Core Application
- Maintaining Core Application break fix issue logging and resolution
- On-going training of staff to support the Core Application and databases
- Provision of facilities including office space, meeting rooms, video conferencing, desktop PC, monitor, telephone, printers, faxes and administrative support for production application support and break-fix personnel
- Disaster Recovery Testing
    - Develop and maintain disaster recovery procedures and testing
    - Conduct disaster recovery tests, post disaster recovery review and maintain the disaster recovery plan

5. Time And Materials Rates

Time and Material Rates will apply for additional work requested by the Client that is to be charged on a Time and Materials Rates basis, and will require a Change Request. Supplier will provide a minimum of 2,000 hours of Services, at the current Time and Materials Rate, to Client annually on a take or pay basis. As outlined in Section 6.6(c) of the Agreement, the Client and Supplier will meet annually to develop a workload plan. Any unused hours will be charged to the Client at the Analyst A4 rate.

The Test Environment Charge will only apply to Change Requests that require integration and regression testing to verify results. The Test Environment Charge

has already been incorporated into the ATCO-CIS Extended Application Maintenance and ATCO-CIS Core Application Maintenance Fee.

6. Pass-Through Charges

The Supplier, on behalf of the Client, can contract for products and services in order to perform the Services as authorized by this Agreement or the Client, as the case may be, and pass the charges onto the Client. Pass Through Charges will be applied in accordance with this Agreement, including documents developed under the Implementation Plan. These Services are described in Schedule A (Definition of Services) of the Agreement as indicated below.

Example:

Fee Schedule: Pass Through Charges

All paper stock, e.g. letterhead, bill stock, mailing and return envelopes, postage and courier services, bank fees, long distance telephone charges, similar items and the like are Pass Through Charges.

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CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Schedule D

Client's Systems

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1.0 Introduction

This is Schedule D to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. ("**Supplier**") and ATCO Electric Ltd. ("**Client**").

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement.

2.0 Client's Systems

Systems owned or licensed to the Client that are utilized in connection with the Services as at the Effective Date and that may be updated during the Term of the contract.

(1) ATCO-CIS

(2) Revenue Forecasting

(3) Work Force Management System

(4) Meter Attribute and Reading Management System

(5) Financial Systems

(6) Load Profiling and Settlement System

(7) Work Order Management

(8) AMR Workstation

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CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Schedule E
Benchmarking Terms of Reference

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CUSTOMER CARE AND BILLING
MASTER SERVICES AGREEMENT

Schedule E – Benchmarking Terms of Reference

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1. Introduction

This is Schedule E to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. (the "**Supplier**") and ATCO Electric Ltd. (the "**Client**").

1.1. Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized works and terms used herein will have the meaning ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Benchmarker**"	means the organization or individual contracted pursuant to the Agreement to prepare the benchmarking study as described in greater detail below.
"**Fair Market Value**"	means the average of the prices charged by other well-managed service providers (Peer Organizations) for work of a similar nature, type and volume.
"**Peer Organizations**"	means the organizations or entities selected by the Benchmarker to be used for Benchmarking.

1.2. Purpose of This Schedule

This Schedule specifies the qualifications of, and process used to select the Benchmarker and Peer Organizations and describes the Benchmarking scope, including the Benchmarking content and approach for evaluating the results of the Benchmarking.

2. Benchmark Scope

2.1. Benchmarking Content

The following subject matter will be benchmarked:

- The Services performed;
- The Service Levels achieved for the Services;
- The Aggregate Volume and any other applicable utility volumes;
- The overall terms and conditions of the Agreement; and
- The Fees, considered as a whole, with consideration to the foregoing factors.

The Benchmarker will also consider:

- The complexity of the Services provided;
- The restructured Alberta regulatory environment;
- ATCO-CIS ownership costs are capitalized by, and reside in, the ATCO Utilities and not the Supplier. The costs include Services associated with the development, implementation and enhancement of the ATCO-CIS, which is used for the delivery of the Services; and

- Supplier pays Pass Through Charges on behalf of the ATCO Utilities;

The Benchmarker will use its Benchmarking methodology to evaluate the overall competitiveness of the Fees for the Services performed and the Service Levels achieved, when compared to Peer Organizations providing equivalent services and service levels with similar complexity, risk and volumes as the Services and Service Levels hereunder, including to establish whether the Fees are at Fair Market Value.

The Supplier and the Client acknowledge and agree that the Benchmarker shall make appropriate adjustments to the information and data obtained in respect of Peer Organizations ("**Adjustments**") in order to ensure that such information and data can be properly, fairly and equitably compared to the Services, the Service Levels and the Fees.

The Benchmarking analysis will not include any review of the Supplier's costs for products and services, internal business processes, organization structure, management practices and/or human resource practices.

2.2. Methodology for Benchmarking

The Supplier hereby consents to the Client's use of any Benchmarker listed in Appendix 1 (Approved List of Benchmarkers) for the purposes of the defined Benchmark. Such Benchmarker list meets the qualifications and criteria for selection. The Benchmarker shall be engaged on terms consistent with Section 8.4 (Price Reviews) of the Agreement and this Section and otherwise acceptable to the Client.

The timing of the Benchmarking shall be consistent with the terms of Section 8.4 (Price Reviews) of the Agreement.

3. The Benchmarker

3.1. Qualifications

The Benchmarker must:

- Be an independent Benchmarker from a North American recognized, reputable firm, acceptable to both Parties;
- Must not be a provider of the Services, direct Client competitor, or a direct Supplier competitor, or affiliated or associated with either Party in such a manner that an objective person would regard the Benchmarker as likely to have a material conflict of interest, and therefore be unable to conduct the benchmark study objectively and independently;
- Have a database with a sufficient number of organizations to make reliable comparisons;
- Have experience working with Distributors in deregulated utility environments;
- Have experience benchmarking service providers in the customer care and billing services industry, those who provide services equivalent to the Services; and
- Have demonstrated experience benchmarking all the subject matter to be benchmarked.

3.2. Selection Process

The process used to revise the Benchmarker list in Appendix 1 (Approved List of Benchmarkers) shall be agreed upon by the Supplier and the Client. If the Parties cannot agree

on such revision process, or on the Benchmarkers to include in the list, either Party may refer the matter to the dispute resolution process set forth in Article 14 (Dispute Resolution) of the Agreement.

3.3. Confidentiality

The Benchmarker shall be required to execute a Non-Disclosure Agreement in a form acceptable to the Supplier and the Client, acting reasonably.

4. Peer Organizations

4.1. Selection

In determining who the Peer Organizations to ATCO I-Tek are, the Benchmarker shall follow these principles:

- The type of services being provided by the Peer Organization should be substantially equivalent to those provided by ATCO I-Tek;
- The risk and liability being assumed by the Peer Organization should be substantially similar to that assumed by ATCO I-Tek; and
- A Peer Organization cannot be a division or affiliate of an integrated utility company.

4.2. Number of Peer Organizations

The Benchmarker shall review a commercially reasonable and appropriate number of Peer Organizations in North America.

4.3. Additional Sources of Information

The Parties acknowledge that the Benchmarker will determine commercially reasonably appropriate sources of additional information to complete the Benchmarking study.

5. Evaluating Results

The Benchmarker will report on the Fees set forth in the then current Schedule C (Fee Schedule) based on a Benchmarking review undertaken in accordance with this Schedule E, including Sections 2 (Benchmark Scope), 3 (The Benchmarker) and 4 (Peer Organizations).

The Benchmarker will provide the Supplier and the Client with a Benchmarking report setting forth the results of the benchmarking process.

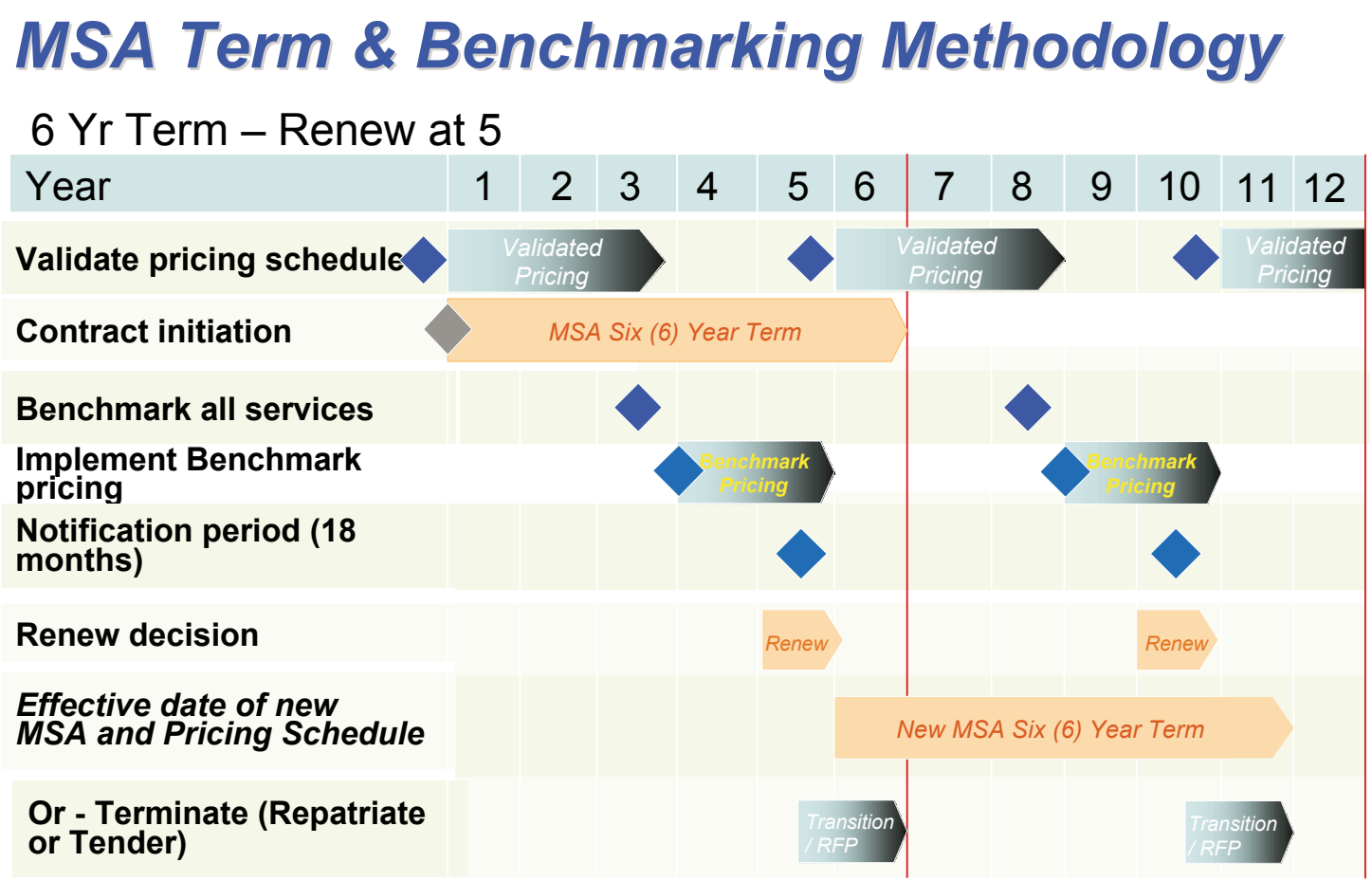
Appendix 1 – Approved List of Benchmarkers

The criteria for an approved Benchmarker are outlined in Section 3.1 of this Schedule. This list shall be reviewed by the Supplier and the Client as part of the annual Service Review. Any additions or deletions to this list must be mutually agreed to and is subject to approval by the Alberta Utilities Commission (AUC).

The following organizations are approved Benchmarkers:

- Booz Allen Hamilton Inc.
- Compass Management Consulting Limited/Utilipoint International Inc.
- Energy Insights Inc, an IDC Company/Pacific Economics Group
- Gartner, Inc.

Appendix 2 – MSA Term and Benchmarking Methodology



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CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Schedule F

Arbitration

1.0 Introduction

This is Schedule F to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. ("**Supplier**") and ATCO Electric Ltd. ("**Client**").

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement.

2.0 Arbitration Procedure

Any Disputes referred to the Panel shall be settled in accordance with the provisions of the *Arbitration Act* (Alberta) and any amendments thereto, upon the following procedure:

1. Subject to paragraph (2), the Panel will be composed of one person appointed by the Party requesting a Panel (the "**Applicant**"), one person appointed by the other Party (the "**Respondent**") and a third person to act as chairperson, chosen by the other two members of the Panel, or, if both Parties agree, the Panel will consist of a sole arbitrator.

2. The Applicant shall deliver to the Respondent notice of its intent to refer the Dispute to the Panel and shall at the same time name its appointee to the Panel. The Respondent shall within fifteen (15) Business Days of receipt of such notice advise the Applicant, in writing, of the name of its appointee to the Panel. If the Respondent fails to notify the Applicant of its appointee, the Respondent shall be deemed to have concurred in the appointment of the arbitrator appointed by the Applicant, and such arbitrator shall constitute the Panel.

3. If the Respondent appoints an arbitrator pursuant to paragraph (2) above, then, within five Business Days of the appointment of such additional arbitrator, the two appointed arbitrators shall agree on the appointment of an additional arbitrator to act as chairperson (the "**Chairperson**"). If the appointed arbitrators cannot agree on the additional arbitrator, the Applicant or Respondent may apply to the Alberta Court to appoint an impartial third member to act as Chairperson or promptly take such other action to appoint a Chairperson as the Parties may agree.

4. No person may be appointed as an arbitrator unless he or she is independent of the Applicant and Respondent, is skilled in the subject matter of the Dispute and is not directly or indirectly carrying on or involved in a business being carried on in competition with the businesses of the Parties.

5. The Panel shall be governed by the Alberta Rules of Court, consistent with the purposes of arbitration in accomplishing fair, speedy and cost effective resolution of Disputes.

6. The decision of the Panel shall be made by a majority vote or by the sole arbitrator, as the case may be. In the event of the failure of the Panel to reach a majority decision, the decision of the Chairperson shall constitute the decision of the Panel.

7. The decision of the Panel with respect to the Dispute shall be made in writing within the thirty (30) Business Days day period following the appointment of the last member to the Panel, shall be final and binding on the Parties, not subject to any appeal, and shall deal with the question of costs of arbitration and all related matters. Such decision shall be deemed to be a judgment rendered by the Alberta Court and is enforceable as such without promulgation.

8. The arbitration shall take place in Edmonton, Alberta.

9. The time limits referred to in this Attachment may be extended by mutual agreement of the Parties.

CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Schedule G

System Access Terms

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This is Schedule G to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. ("**Supplier**") and ATCO Electric Ltd. ("**Client**").

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Accessing Party**" has the meaning described in Sections A.1(a) and B.1(a);

"**Purpose**" has the meaning described in Sections A.1(a)(i) and B.1(a)(i); and

"**User IDs**" has the meaning described in Sections A.1(c) and B.1(c).

A. The Parties agree that the following provisions shall apply with respect to Access by the Client to the Client Data:

1. System Access

(a) The Supplier shall permit the Client and its Representatives (in each case, an "**Accessing Party**") to have Access to the Supplier's Systems, but only:

(i) to obtain Access to the Client Data (the "**Purpose**");

(ii) subject to strict compliance with the terms and conditions set out in the Agreement and this Schedule;

(iii) subject to compliance with and observance of the policies and procedures implemented by Supplier from time to time in respect of the Supplier's Systems, of which the Client is made aware.

(b) The Supplier may amend, add to or modify the policies and procedures in respect of the Supplier's Systems from time to time and any amended, additional or modified policies and procedures shall be effective from the time that the Supplier provides them to the Client.

(c) The Supplier shall provide the Accessing Party with such user identification codes or code generators or mechanisms (collectively, "**User IDs**") as are necessary for the Accessing Party to Access the Supplier's Systems pursuant to this Agreement for the Purpose.

(d) No right, title or interest to the Supplier's Systems is transferred to the Accessing Party except the limited license to Access the Supplier's Systems upon the terms and conditions expressly set out in this Agreement.

2. Accessing Party Obligations of Client and its Representatives

(a) The Accessing Party shall:

(i) abide by all policies, standards and procedures of the Supplier regarding the use of and access (including Access) to the Supplier's Systems, as amended from time to time, of which the Client is made aware;

(ii) select passwords of a minimum length of seven (7) characters and of reasonable complexity and shall change passwords not less frequently than once every thirty-three (33) days;

(iii) comply with, abide by and use all security mechanisms that are incorporated into and form part of the Supplier's Systems and the Client's Systems;

(iv) not permit any unauthorized computer program, functionality, routine, utility, code, data, resources, capabilities or devices to be introduced to any part of the Supplier's Systems except as expressly authorized in writing by the Supplier, and without limiting the generality of the foregoing, shall not permit and shall take reasonable steps to prevent the entry of any computer virus program, trojan horse program, worm program or other unauthorized computer program into any part of the Supplier's Systems;

(v) not attempt to circumvent the security features of the Supplier's Systems or any part thereof including testing or examining such security features;

(vi) not deliberately attempt to degrade the Supplier's Systems performance or otherwise attempt to cause any damage to the Supplier's Systems or any part thereof;

(vii) disclose or share any User IDs, passwords or other methods of access with any person;

(viii) not copy or store any computer data or computer software Accessed hereunder without the prior written consent of the Supplier.

3. The Client's Obligations

(a) The Client shall, and shall ensure that each of its Representatives who are Accessing Parties shall:

(i) provide a reasonable level of protection and security for the Supplier's Systems Accessed hereunder, including data, databases, computer programs and resources of Supplier in order to prevent the disclosure of, unauthorized use of or unauthorized access to the Supplier's Systems, including any such data, databases, computer programs or other resources.

(ii) be solely responsible for the integrity of its own data, computer software, middleware, firmware, hardware (including peripheral equipment) and telecommunications services and equipment, used to Access the Supplier's Systems; including the creation of security access restrictions to its data.

(iii) permit the Supplier escorted, reasonable access during normal business hours to the Client's premises, data, information, records, computers and other materials for the purpose of permitting the Supplier to monitor compliance with the terms of this Agreement.

(iv) upon request from the Supplier from time to time, provide proof that the Client has complied with the requirements set out in Section A(3)(a)(i) to (iii).

4. Termination

(a) The Supplier may terminate the Access of an Accessing Party if the Accessing Party has breached any of its obligations pursuant to this Schedule and shall terminate Access upon the expiry or early termination of the Agreement.

B. The Parties agree that the following provisions shall apply with respect to the Supplier's access to the Client's Systems:

1. System Access

(a) The Client shall permit the Supplier and its Representatives (in each case, an "**Accessing Party**") to have access to the Client's Systems, but only:

(i) to obtain access to the Client's Systems for the purpose of fulfilling the Supplier's obligations under this Agreement (the "**Purpose**");

(ii) subject to strict compliance with the terms and conditions set out in the Agreement and this Schedule;

(iii) subject to compliance with and observance of the policies and procedures implemented by the Client from time to time in respect of the Client's Systems, of which the Supplier is made aware.

(b) The Client may amend, add to or modify the policies and procedures in respect of the Client's Systems from time to time and any amended, additional or modified policies and procedures shall be effective from the time that the Client provides them to the Supplier.

(c) The Client shall provide the Accessing Party with such user identification codes or code generators or mechanisms (collectively, "**User IDs**") as are necessary for the Accessing Party to access the Client's Systems pursuant to this Agreement for the Purpose.

(d) No right, title or interest to the Client's Systems is transferred to the Accessing Party except the limited license to access the Client's Systems upon the terms and conditions expressly set out in this Agreement.

2. Accessing Party Obligations of Supplier and its Representatives

(a) The Accessing Party shall:

(i) abide by all policies, standards and procedures of the Client regarding the use of and access to the Client's Systems, as amended from time to time, of which the Supplier is made aware;

(ii) select passwords of a minimum length of seven (7) characters and of reasonable complexity and shall change passwords not less frequently than once every thirty-three (33) days;

(iii) comply with, abide by and use all security mechanisms that are incorporated into and form part of the Supplier's Systems and the Client's Systems;

(iv) not permit any unauthorized computer program, functionality, routine, utility, code, data, resources, capabilities or devices to be introduced to any part of the Client's Systems except as expressly authorized in writing by the Client, and without limiting the generality of the foregoing, shall not permit and shall take reasonable steps to prevent the entry of any computer virus program, trojan horse program, worm program or other unauthorized computer program into any part of the Client's Systems;

(v) not attempt to circumvent the security features of the Client's Systems or any part thereof including testing or examining such security features;

(vi) not deliberately attempt to degrade the Client's Systems performance or otherwise attempt to cause any damage to the Client's Systems or any part thereof;

(vii) disclose or share any User IDs, passwords or other methods of access with any person;

(viii) not copy or store any computer data or computer software accessed hereunder without the prior written consent of the Client.

3. The Supplier's Obligations

(a) The Supplier shall, and shall ensure that each of its Representatives who are Accessing Parties shall:

(i) provide reasonable level of protection and security for the Client's Systems Accessed hereunder, including data, databases, computer

programs and resources of the Client in order to prevent the disclosure of, unauthorized use of or unauthorized access to the Client's Systems, including any such data, databases, computer programs or other resources.

(ii) be solely responsible for the integrity of its own data, computer software, middleware, firmware, hardware (including peripheral equipment) and telecommunications services and equipment, used to access the Client's Systems; including the creation of security access restrictions to its data.

(iii) permit the Client escorted, reasonable access during normal business hours to the Supplier's premises, data, information, records, computers and other materials for the purpose of permitting the Client to monitor compliance with the terms of this Agreement.

(iv) upon request from the Client from time to time, provide proof that the Supplier has complied with the requirements set out in Section B(3)(a)(i) to (iii).

4. Termination

The Client may terminate the access of an Accessing Party if the Accessing Party has breached any of its obligations pursuant to this Schedule G and shall terminate access upon the expiry or early termination of the Agreement.

CUSTOMER CARE AND BILLING

MASTER SERVICES AGREEMENT

Schedule H

Termination Transition Plan

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A. Introduction

This is Schedule H to the Customer Care and Billing Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Business Services Ltd. ("**Supplier**") and ATCO Electric Ltd. ("**Client**").

B. Termination Transition Plan

1. Detailed Termination Transition Plan

Upon a notice of termination being given under this Agreement, a detailed Termination Transition Plan shall be prepared at the Client's sole cost and expense pursuant to a Statement of Work, and shall include each of the following items:

(a) Name of Party to whom the Services shall be transitioned

(b) Scope Statement

(c) Format and Form of Deliverables

(d) Transition Team Members including steering committee

(e) Review of Statements of Work in effect at the date of termination

(f) Detailed project plan

(g) Detailed Training Requirements

(h) Fees Schedule

(i) Client responsibilities during the Termination Transition Assistance Period

(j) Supplier responsibilities during the Termination Transition Assistance Period

(k) Change Implementation

(l) Acceptance Process

(m) Authorization signatures

2. Client Data

Upon termination of this Agreement for any reason, the Supplier shall convert (to industry standard file formats) and make available to the Client, or as the Client directs, all Client Data in the possession, custody or control of the Supplier, and if no direction is provided by the Client to the Supplier, the same shall be delivered up to the Client within one hundred eighty (180) days following termination of this Agreement. The Client shall pay for any required conversion services (in the event Client Data is stored in a proprietary or confidential file format) at the Time and Materials Rate.

3. Return of Client Property

At the end of the Termination Transition Assistance Period, or earlier, where appropriate in the circumstances, the Supplier shall return to the Client (in the format mutually agreed to in the Termination Transition Plan) all property belonging to the Client, including Client Know-How, Client's Systems and the Client's Confidential Information that are in the Supplier's possession or control.

4. Return of Supplier Property

At the end of the Termination Transition Assistance Period, or earlier, where appropriate in the circumstances, the Client will return to the Supplier all property belonging to the Supplier, including Supplier Know-How, the Supplier's Systems, the Supplier's Confidential Information, and Documentation belonging to the Supplier.

5. Training

During the Termination Transition Assistance Period, the Supplier shall provide training related to the Systems and Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work.

6. Consulting

During the Termination Transition Assistance Period, where appropriate in the circumstances, the Supplier shall provide consulting services related to the Systems or Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work. The Supplier shall perform the Termination Transition Services in a timely, workmanlike, competent, conscientious and professional manner, in accordance with generally accepted standards of care in the distribution energy customer care and billing industry.

INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

FOR

ATCO ELECTRIC LTD.

ATCO I-Tek
10035 105 Street
Edmonton, Alberta
T5J 2V6

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INFORMATION TECHNOLOGY MASTER SERVICES AGREEMENT

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INFORMATION TECHNOLOGY MASTER SERVICES AGREEMENT

BETWEEN:

ATCO I-Tek Inc.
("**ATCO I-Tek**")

- and -

ATCO Electric Ltd.
("**Client**")

WHEREAS:

A. ATCO I-Tek has provided information technology services for Client's business pursuant to that certain Master Services Agreement dated January 1, 2005 (the "MSA");

B. Effective as of the Commencement Date, Client requires information technology services for its ongoing business;

C. ATCO I-Tek has agreed to provide information technology services to each of the ATCO Utilities (as hereinafter defined) who signs an agreement substantially in the form of this Agreement, on the terms and conditions set forth below;

D. From and after the Commencement Date, this Agreement replaces and supersedes the MSA which is hereby terminated and of no further force or effect; and

E. Client is one of the ATCO Utilities;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto do hereby agree as follows.

ARTICLE 1
INTERPRETATION AND DEFINITIONS

1.1 Interpretation

(a) Wherever in this Agreement the context so requires, the singular number shall include the plural number and vice versa, any gender shall include the feminine, masculine or neuter genders, and person shall include an individual, partnership, corporation (including a business trust), trust, unincorporated association, joint venture, government or other entity, or any agency, department or instrumentality thereof and vice versa. Where a term is defined in this Agreement, a derivative of that term shall have a corresponding meaning unless the context otherwise requires.

(b) The term "**including**" shall be read as "**including, but not limited to**" Other expressions derived from the word "**include**" are for illustrative purposes only and are not meant to be limiting.

(c) The insertion of headings herein and the division of this Agreement into articles and sections are for convenience of reference only and shall not affect the interpretation hereof. The words "**hereof**", "**hereunder**" and similar expressions refer to this Agreement in its entirety and not any particular Article or Section hereof. The words "**article**", "**section**", and "**subsection**" mean and refer to the specified article, Section or subsection of this Agreement.

(d) Reference to any agreement, indenture or other instrument in writing means such agreement, indenture or other instrument in writing as amended, modified, replaced or supplemented from time to time, unless otherwise agreed to herein.

(e) Reference to any statute or regulation or bylaw shall be deemed to be a reference to such statute or regulation or bylaw as amended, re-enacted or replaced from time to time, unless otherwise agreed to herein.

(f) Time periods within which a payment is to be made or any other action is to be taken hereunder shall be calculated excluding the day on which the period commences, but including the day on which the period ends; and

(g) Whenever any payment to be made or action to be taken hereunder is required to be made or taken on a day other than a Business Day, such payment shall be made or action taken on the next following Business Day.

1.2 **Definitions**

Whenever used in this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following capitalized words and phrases shall have the respective meanings ascribed to them as follows:

"**Accessing Party**" has the meaning given in Section 5.9 (Compliance With Policies).

"**Acknowledgement**" has the meaning given in Section 10.3 (Intellectual Property Indemnity).

"**Affiliate**" has the meaning given in the *Business Corporations Act* (Alberta).

"**Agreement**" means this Information Technology Master Services Agreement, including the Schedules hereto and any Statements of Work attached hereto or as may be executed by the Parties at a future date, as well as all amendments, additions or modifications thereto.

"**Aggregate Volume**" means the aggregate volume of Services being delivered to and/or used by all of the ATCO Utilities.

"**Annual Review**" has the meaning given in Section 7.2 (Annual Planning Reviews).

"**Applicable Law**" means the following as it is applicable to the performance of this Agreement:

(a) statute or proclamation or any delegated or subordinate legislation including Laws in any jurisdiction and which shall include Data Protection Legislation;

(b) Authority Requirements; and

(c) judgment of a court of law, board, arbitrator or administrative agency of competent jurisdiction.

"**Applicant**" has the meaning given in Section 16.2 (Arbitration).

"**Arbitration Act**" has the meaning given in Section 16.2 (Arbitration).

"**Associate**" has the meaning given in the *Business Corporations Act* (Alberta).

"**ATCO Electric**" means ATCO Electric Ltd.

"**ATCO Gas**" means ATCO Gas, an operating name and division of ATCO Gas and Pipelines Ltd.

"**ATCO Pipelines**" means ATCO Pipelines, an operating name and division of ATCO Gas and Pipelines Ltd.

"**ATCO Group**" means ATCO Ltd., Canadian Utilities Limited and their respective Affiliates and Associates.

"**ATCO I-Tek Designated Manager**" has the meaning given in Section 5.2 (ATCO I-Tek Designated Manager).

"**ATCO I-Tek Know-How**" has the meaning given in Section 13.6 (ATCO I-Tek Know-How).

"**ATCO I-Tek Policies**" has the meaning given in Section 5.1(c) (General).

"**ATCO I-Tek Project Manager**" has the meaning given in Section 5.4 (ATCO I-Tek Project Manager).

"**ATCO I-Tek Systems**" means any Systems owned by ATCO I-Tek or licensed to ATCO I-Tek by Third Parties, and utilized to provide the Services.

"**ATCO Utilities**" means ATCO Electric, ATCO Gas, ATCO Pipelines and their respective Subsidiaries.

"**Authority Requirements**" means any ruling, determination, order, direction, directive, request for information, policy, administrative position or interpretation, guideline or rule of (or by) any Governmental Authority of competent jurisdiction concerning this Agreement.

"**Benchmarker**" has the meaning given in Section 7.3 (Price Reviews).

"**Benchmarking**" has the meaning given in Section 7.3 (Price Reviews).

"**Board**" has the meaning given in Section 16.2 (Arbitration).

"**Business Day**" means each of Monday, Tuesday, Wednesday, Thursday and Friday, except when the day occurs on a statutory holiday observed in the Province of Alberta.

"**Business Hours**" means the hours of 8:00 a.m. to 5:00 p.m., Mountain Time, during any Business Day.

"**Calendar Year**" means the year as designated by the Gregorian calendar in common use as beginning on January 1st and ending on December 31 of that same year.

"**Chairperson**" has the meaning given in Section 16.2 (Arbitration).

"**Change**" means any change, modification or enhancement to the provision of the Services which requires an amendment to this Agreement.

"**Change in Law**" means the issuance, creation, adoption, enactment, promulgation, modification, amendment, or revocation after the execution of this Agreement of any Applicable Law concerning this Agreement, including the performance of the Services, and including by way of example only those which may be related to, or affect the following:

(a) the gas sector, including any re-regulation or deregulation affecting supply, sale, distribution or transmission of natural gas, including customer choice of service provider;

(b) the electricity sector, including re-regulation or deregulation affecting generation, supply, sale, distribution or transmission of electricity, including customer choice of service provider; or

(c) the information technology service or customer care and billing services businesses.

"**Change Management Co-Ordinator**" has the meaning given in Section 2.9(e)(i) (Changes in Services) (Cancellation or Rescheduling of Change Window by Client).

"**Change Response**" has the meaning given in Section 2.9(a) (Changes in Service) (Change Request).

"**Change Window**" means a predefined, regularly scheduled block of time set aside to implement hardware and software changes.

"**Claim**" means any and all claims, actions, damages, liabilities, losses, penalties, causes of action, suits, proceedings, judgments, demands of whatsoever nature, costs and expenses, including reasonable legal fees and disbursements.

"**Client Data**" means the data provided to ATCO I-Tek by Client or obtained by ATCO I-Tek acting on behalf of Client, and all data derived from such data.

"**Client Designated Manager**" has the meaning given in Section 5.3 (Client Designated Manager).

"**Client Know-How**" has the meaning given in Section 13.7 (Client Know-How).

"**Client Project Manager**" has the meaning given in Section 5.5 (Client Project Manager).

"**Client Systems**" means any Systems owned by Client or licensed to Client by Third Parties.

"**Commencement Date**" means the date, set by agreement of the Parties in writing, on which the Services shall commence.

"**Computer Viruses**" has the meaning given in Section 9.2(c) (Representations, Warranties and Covenants of ATCO I-Tek).

"**Confidential Information**" has the meaning given in Section 14.1 (Confidential Information).

"**D/E**" has the meaning given in Section 6.6 (Workload Planning).

"**Date Compliance**" means that all software, hardware and equipment, whether individually or as a system, containing date-recording or date sensitive electronic components and used, directly or indirectly, by a Party hereto:

(a) is designed to be used and will, correctly and without human intervention, store, record, process, use, calculate, sequence and exchange data that references dates without error relating to date data, and will operate transparently to the user during such time periods without a difference in functionality or performance;

(b) is capable of operating without error relating to logical or mathematical operations, or both, carried out on date data that represents or references different centuries or more than one century;

(c) correctly recognizes a leap year;

(d) does not use date fields as indicators, or for purposes other than to store valid dates;

(e) will not experience interruption, malfunction or failure as a result of any value of current date; and

(f) is designed such that the century in all data fields, date-related user interfaces and other interfaces is specified either explicitly or by unambiguous algorithms or inferencing rules (and that, in the latter case, the products or systems respond to two-digit year dates in a way that resolves

the ambiguity as to the century in a disclosed, defined and pre-determined manner).

"**Data Protection Legislation**" means the applicable international and Canadian federal or provincial legislation dealing with privacy, specifically, as at the Effective Date, the *Personal Information Protection and Electronic Documents Act*, S.C. 2000, c. 5; *Personal Information Protection Act*, S.A. 2003, c. P-6.5; (collectively the "**Privacy Acts**").

"**Deliverable**" means a deliverable which arises from the Services and which ATCO I-Tek has agreed in writing to deliver to Client.

"**Designated Manager**" means the ATCO I-Tek Designated Manager or the Client Designated Manager as the context may require.

"**Designated Representative**" has the meaning given in Section 5.6 (Selection of Representatives).

"**Designating Party**" has the meaning given in Section 5.6 (Selection of Representatives).

"**Disclosing Party**" has the meaning given in Section 14.1 (Confidential Information).

"**Discretion**" means sole, absolute and unfettered discretion and, in each case where such term is used in conjunction with the provision of consent, also means that the person whose consent is required may unreasonably and arbitrarily withhold such consent.

"**Dispute**" means any dispute, controversy or claim arising out of or in connection with this Agreement or the breach, termination, validity or enforceability of any provision of this Agreement.

"**Documentation**" means any documentation, manuals or other guides provided by ATCO I-Tek to Client to support Client's use of the Services.

"**Effective Date**" means January 1, 2010.

"**Emergency Services**" means an unplanned change scheduled outside of the normal Change Window to correct or avoid a high severity outage, being a problem to which a "critical" priority code is attached in Schedule C (Service Measures).

"**Extraordinary Event**" means an event or discrete set of events that has occurred or is planned with respect to the business of Client that results in a change in the scope, nature or volume of the Services that Client will require from ATCO I-Tek and on which Schedule D (Pricing) is based.

"**Governmental Authority**" means a court, ministry, minister, official, government department, government authority, government agency, commissions, regulatory authority, regulatory agency, administrative tribunal, body that administers Laws, or body having competent authority concerning this Agreement.

"**Granting Party**" has the meaning given in Section 5.9 (Compliance With Policies).

"**Indemnified Persons**" means, with respect to a Party, its Representatives, shareholders, directors, officers, consultants, suppliers, Affiliates and Associates.

"**Indemnitee**" has the meaning given in Section 10.1 (Cross Indemnity).

"**Indemnitor**" has the meaning given in Section 10.1 (Cross Indemnity).

"**Interest**" means interest calculated at a rate equal to two percent (2%) per annum above the prime rate established from time to time by the main branch in Edmonton of the Bank of Montreal, calculated and payable monthly.

"**IP Indemnitor**" has the meaning given in Section 9.1(f) (Mutual Representations, Warranties and Covenants).

"**IP Rights**" means all intellectual property, industrial property and other proprietary rights, whether conferred by statute, common law, contract, equity or otherwise, including copyright, patent, integrated circuit topography, trade secret, trade-mark rights and comparable rights, and rights of ownership of applicable applications and registrations.

"**IT**" means Information Technology.

"**IT Plan**" has the meaning given in Section 7.2 (Annual Planning Reviews).

"**Laws**" means all federal, provincial, state, local and municipal statutes, laws, by-laws, rules, codes, ordinances, orders (including court orders), directions and regulations in effect from time to time and made or issued by a Governmental Authority.

"**Material Breach**" means the failure of any Party to perform any obligations hereunder that has a material adverse effect on the other Party.

"**Other Party**" has the meaning given in Section 5.6 (Selection of Representatives).

"**Party**" or "**Parties**" means a party or both parties to this Agreement, as applicable.

"**Personal Information**" has the meaning set out in all applicable Canadian federal or provincial legislation dealing with privacy, including, as at the Effective Date, the Privacy Acts and includes all Personal Information, as that term is defined therein regarding identifiable individuals, who are customers of Client and all employees of ATCO I-Tek and Client.

"**Pre-paid Technology Expense**" means a one time cost that will be charged to Client for technology that belongs to ATCO I-Tek but is used by Client, including hand-held devices.

"**Privacy Acts**" has the meaning given in the definition of "**Data Protection Legislation**".

"**Project Manager**" means the ATCO I-Tek Project Manager or the Client Project Manager as the context may require.

"**Recipient**" has the meaning given in Section 14.1 (Confidential Information).

"**Renewal Notice**" has the meaning given in Section 15.2 (Renewal).

"**Representatives**" means officers, employees, agents or contractors of a Party, and shall include the Designated Manager, Statement of Work Manager and Project Manager of each Party, and the Change Management Coordinator.

"**Request**" has the meaning given in Section 4.1 (Development of Statements of Work).

"**Respondent**" has the meaning given in Section 16.2 (Arbitration).

"**Review Period**" has the meaning given in Section 4.3 (Approval of Deliverables).

"**Schedule**" means each completed Schedule that is attached to and forms part of this Agreement.

"**Service Credit**" means the amounts determined by the Parties for not achieving a Service Level associated with a Critical Measure (as defined in Schedule C (Service Measures) as set forth in Schedule C (Service Measures).

"**Service Level**" means the level of performance to be achieved for certain Services as set out in Schedule C (Service Measures).

"**Service Policies**" means the policies of Client applicable to the Services as the same may be amended, supplemented, superseded or replaced from time to time.

"**Services**" means the services to be provided by ATCO I-Tek to Client as set out in Schedule A (Service Levels) and Schedule B (Definition of Services) and such other services as the Parties may agree to from time to time pursuant to Section 2.1 (Provision of Services) or any Statement of Work, including all Deliverables, including but not limited to the following service categories ("**Service Categories**", each being a "**Service Category**"):

(a) Application Service Provider Service (ASP)

(b) Distributed Server and Application Managed Service

(c) Mainframe Service

(d) Project Labour Service

(e) Storage Service

(f) User Connectivity Service

(g) Network Connectivity Service

(h) Voice Service

(i) Workstation Service

but specifically excluding any services identified in Schedule B (Definition of Services) as "optional services" except to the extent that Client has elected in writing to have ATCO I-Tek provide such optional services to Client.

"**Specified Expense**" means service fees that are routine costs from Third Parties, that are incurred by ATCO I-Tek in delivering the Services as requested by Client. Such expenses are incremental to the Third Party costs contained within the base Service fees. Specified Expenses will be a flow through charge to Client as set out in Schedule D (Pricing).

"**Statement of Work**" means work requested by Client to undertake a specific project, which upon its completion will result in services additional to the Services then being performed by ATCO I-Tek.

"**Statement of Work Manager**" has the meaning given in Section 4.1(b) (Development of Statements of Work).

"**Subsidiary**" has the meaning given in the *Business Corporations Act* (Alberta).

"**System**" means hardware, firmware, middleware, computer software programs and supporting documentation, including interfaces, utilities, data, input and output formats, program listings, narrative descriptions and operating instructions, and all updates, enhancements or changes to the foregoing.

"**Term**" has the meaning given in Section 15.1 (Term).

"**Termination Transition Plan**" has the meaning given in Section 15.6(e) (Effect of Termination).

"**Termination Transition Services**" has the meaning given in Section 15.6(e) (Effect of Termination).

"**Third Party (Parties)**" means a party or parties other than a Party or an Affiliate of a Party.

"**Tier 1 Services**" means operational Services ("Mouse pad to Server") described in Schedule B (Definition of Services) and any Statement of Work.

"**Tier 2 Services**" means services in connection with new IT-related projects exceeding forty (40) man-days, including systems development and major enhancements, described in Schedule B (Definition of Services) and any Statement of Work.

"**Tier 3 Services**" means Services related to corporate technology strategy, including investment Services, business process improvement and technology advice, as described in Schedule B (Definition of Services) and any Statement of Work.

"**Time and Materials Rate**" means the hourly charge based on the level of resources pursuant to Schedules B (Definition of Services) and Schedule D (Pricing) and reasonable expenses.

"**Transition Assistance Period**" has the meaning given in Section 15.6(e) (Effect of Termination).

"**Triggering Event**" has the meaning given in Section 15.4 (Triggering Event).

"**Wynford Group Survey for Alberta**" means the salary survey for the Province of Alberta published by the Wynford Group.

"**Work Location**" means the location at which the Services are rendered.

1.3 **Fair Meaning**

Any ambiguities concerning the terms and conditions of this Agreement shall not be resolved against the drafting Party. Any ambiguous or uncertain terms herein shall be given their fair and reasonable meaning, taking into account, in part, the context of its use herein and the intentions of the Parties.

1.4 **Meaning of Terms**

All terms defined in the main body of this Agreement shall have the same meaning in all Schedules attached hereto, unless otherwise expressly defined therein.

1.5 **Amendments and Priority of Contract Documents**

Except as otherwise provided in this Agreement, this Agreement may not be amended, modified or superseded unless expressly agreed to in writing by both Parties. Without limiting the generality of the foregoing a Statement of Work will not have the effect of amending or overriding this Agreement unless the Statement of Work does so expressly and is agreed to in writing signed by both Parties. For the purposes of resolving any conflict within this Agreement, the order of priority of interpretation to resolve any conflict or contradiction of relevant terms and conditions in this Agreement shall, from highest to lowest in order of specificity over generality, be as follows:

(i) Highest – Schedules to this Agreement; and

(ii) Next Highest – main body of this Agreement.

1.6 **Schedules**

This Agreement includes the following Schedules, which are included in and form part of this Agreement:

Schedule A – Service Levels

Schedule B – Definition of Services

Schedule C – Service Measures

Schedule D – Pricing

Schedule E – Special Terms

Schedule F – Termination Transition Plan

Schedule G – Benchmarking Terms of Reference

ARTICLE 2
SERVICES

2.1 Provision of Services

Commencing on the Effective Date, ATCO I-Tek agrees to provide to Client, and Client agrees to obtain from ATCO I-Tek, the Services, on the terms and conditions set forth herein. ATCO I-Tek and Client shall cooperate to achieve reasonable economy, efficiency and effectiveness in the provision of the Services. The Services, as further described in Schedule B (Definition of Services), shall be set forth in Statements of Work pursuant to Article 4 (Statements of Work and Approval of Deliverables).

Unless otherwise specified herein, Services (other than Emergency Services and Services required to be provided during a Change Window) will be performed during Business Hours. All inclusions and exclusions for Tier 1 Services are outlined in Schedule B (Definition of Services).

For Tier 2 Applications Development Services, where the approved Statement of Work does not specifically include in its scope the performance of Services outside Business Hours, Services performed after Business Hours will be performed at the Discretion of ATCO I-Tek and at no extra cost.

2.2 Project Management

Client and ATCO I-Tek will utilize a common project management methodology that is consistent with commercially reasonable industry practices and standards. ATCO I-Tek will maintain the project management methodology that is used in the delivery of services. ATCO I-Tek will periodically update the project management methodology. The project management reporting and documentation will be agreed to by Client and ATCO I-Tek. ATCO I-Tek will participate in appropriate project management programs.

2.3 Use of Other Suppliers

ATCO I-Tek retains a "right of first proposal" on all new Tier 2 Services required by Client. All new Tier 2 Services required by Client shall commence with a Request, as provided for in Section 4.1 (Development of Statements of Work). However, if within a reasonable time following the making of a Request, Client and ATCO I-Tek have not agreed on a Statement of Work (i.e. Client has not received a proposal from ATCO I-Tek that is acceptable to Client), Client may select another service provider. In the event that Client selects a service provider other than ATCO I-Tek to perform such Tier 2 Services, Client shall pay ATCO I-Tek at the Time and Materials Rate for any material increase in

Services required from ATCO I-Tek to integrate such Tier 2 Services, or any Deliverables arising from such Services, into the Tier 1 Services and any Tier 2 Services provided by ATCO I-Tek.

2.4 **System Changes**

ATCO I-Tek may make modifications to any System that is used to provide the Services as such modifications are required in order to conform the provision of the Services to industry or regulatory changes and to implement general enhancements to the Services. ATCO I-Tek shall initiate the modifications in accordance with the pre-defined change process.

2.5 **Client Support**

ATCO I-Tek's Customer Support Center will provide Client with 24 hour support as provided for in Schedule C (Service Measures).

2.6 **Other Services**

Any services other than the Services that are requested by Client and that ATCO I-Tek is willing to provide will, unless otherwise agreed in writing by Client and ATCO I-Tek, be provided at the Time and Materials Rate. Such other services shall, from the time that both Parties agree in writing to the provision of such other services, thereafter be deemed to form part of the Services for the purposes of this Agreement.

2.7 **Compliance with Applicable Law**

In providing the Services, ATCO I-Tek agrees to comply with Applicable Law to obtain and comply with any necessary regulatory approvals, and to obtain any necessary permits. The Parties shall consult and cooperate with one another to provide the Services in compliance with Applicable Law. In performing its obligations under this Agreement, ATCO I-Tek shall not be required to undertake any activity that would conflict with the requirements of any Applicable Law.

Client agrees to, at its sole expense, comply with Applicable Law, obtain and comply with any necessary regulatory approvals, independently examine government regulations, and obtain any necessary permits applicable to ATCO I-Tek's provision, or Client's use, of the Services. The Parties shall consult and cooperate with one another to provide the Services in compliance with Applicable Law.

2.8 **Service Credits**

The Parties acknowledge that, where the Parties have established Service Levels with respect to certain portions of the Services, and where Service Credits to Client are expressly provided for in Schedule C (Service Measures), Client will receive such Service Credits on the terms and conditions in connection therewith set forth in Schedule C (Service Measures). Without limiting Client's other rights and remedies pursuant to other provisions of this Agreement, and in particular Section 18.14 (Remedies

Cumulative), and including those relating to a Material Breach, such Service Credits, if any, shall constitute Client's exclusive remedy for any failure of ATCO I-Tek to achieve the relevant Service Level. Any Dispute in respect of such Service Credits shall be determined in accordance with the Dispute resolution process set out in Article 16 (Dispute Resolution).

2.9 **Changes in Services**

In the event that Client or ATCO I-Tek desires to make a Change to the Services or to the provisions of a Statement of Work, the following procedure will be followed:

(a) **Change Request** Subject to subsection (b) hereof, ATCO I-Tek, with the assistance of Client, shall, as soon as reasonably practical after receipt of a request for a Change (or development of a proposal for a Change, in the case of a Change proposed by ATCO I-Tek), develop and deliver to Client a response ("**Change Response**"):

(i) specifying how the proposed Change will be implemented;

(ii) describing the effect, if any, that such Change will have on the Schedule for performance of the Services;

(iii) specifying the applicable acceptance testing and acceptance procedures to implement the Change, if any;

(iv) describing the changes to charges, if any, that would result from the implementation of such Change; and

(v) providing sufficient supporting documentation to justify any change in the Schedule for performance or in the cost of executing such Change.

(b) **Additional Charges** Prior to preparing the Change Response, ATCO I-Tek will notify Client of any costs which must be incurred to prepare the Change Response. In such event, Client may:

(i) withdraw the request for the Change; or

(ii) authorize ATCO I-Tek in writing to proceed to prepare the Change Response, in which event Client will be liable to ATCO I-Tek for reasonable costs which it must incur to prepare the Change Response.

Upon receiving such authorization, ATCO I-Tek will make commercial reasonable efforts, in line with the size and scope of the request, to prepare the Change Response.

If the number of Change Responses that ATCO I-Tek is required to prepare in any month exceeds ATCO I-Tek's capacity to properly handle such work, ATCO I-Tek will give notice thereof to Client. In such event, the Parties will meet promptly:

(i) to identify the requests for Change that may be deferred or withdrawn, and to prioritize the remaining requests for Change;

(ii) to discuss what additional costs ATCO I-Tek is required to incur to permit it to prepare the Change Responses, and to determine whether Client should compensate ATCO I-Tek for any of such additional costs; and

(iii) to assess whether any other solution is available.

(c) **Change Response** Promptly after ATCO I-Tek delivers a Change Response to Client, both Parties will meet to determine whether to proceed with the Change in accordance with the Change Response. All approved Change Responses shall be deemed part of the Statement of Work, where applicable, and shall be implemented by the applicable Parties. If any approved Change Response requires an amendment of this Agreement, such amendment must be made prior to the Change in question being effected and in accordance with Section 1.5 (Amendments and Priority of Contract Documents).

(d) **Reasonable Requests** Each Party shall reasonably consider any Change proposed by the other, and shall, subject to the procedure set forth elsewhere in this Section 2.9, not acting in bad faith, use commercially reasonable efforts to negotiate a mutually agreeable agreement in respect of reasonable requests thereof.

(e) **Cancellation or Rescheduling of Change Window by Client** If Client requests that ATCO I-Tek cancel or reSchedule a Change Window, the following rules shall apply:

(i) if one or more of ATCO I-Tek's clients other than Client requests that the Change Window proceed as scheduled, a Representative of ATCO I-Tek selected by it to mediate the conflict (the "**Change Management Coordinator**") shall mediate the conflict between Client and the other ATCO I-Tek client or clients;

(ii) ATCO I-Tek will assist Client in identifying the technical (but not the business or legal) risks associated with cancelling or rescheduling the Change Window;

(iii) if the Change Window is cancelled or rescheduled and ATCO I-Tek has already incurred out-of-pocket expenses with respect to the cancelled or rescheduled Change Window, Client will

reimburse ATCO I-Tek the amount of such expenses forthwith upon receiving an invoice in respect of same; and

(iv) notwithstanding anything else to the contrary in this Agreement, ATCO I-Tek shall not in any event be responsible for any Claims related to the cancellation or rescheduling of the Change Window, nor shall Client seek recourse against any other client of ATCO I-Tek in respect thereof.

(f) **Conflict in Scheduling of Change Window** If one or more of ATCO I-Tek's clients other than Client requests that ATCO I-Tek cancel or reschedule a Change Window, the following rules shall apply:

(i) if Client requests that the Change Window proceed as scheduled, the Change Management Coordinator shall mediate the conflict between Client and the other ATCO I-Tek client or clients;

(ii) ATCO I-Tek will assist Client in identifying the technical (but not the business or legal) risks associated with cancelling or rescheduling the Change Window;

(iii) if the Change Window is cancelled or rescheduled and ATCO I-Tek has already incurred out-of-pocket expenses with respect to the cancelled or rescheduled Change Window, ATCO I-Tek will not look to Client for recovery of such expenses; and

(iv) notwithstanding anything else to the contrary in this Agreement, ATCO I-Tek shall not in any event be responsible for any Claims related to the cancellation or rescheduling of the Change Window, nor shall Client seek recourse against any other client of ATCO I-Tek in respect thereof.

ARTICLE 3
INSURANCE

3.1 **Insurance Obligations of ATCO I-Tek**

ATCO I-Tek shall obtain and maintain throughout the duration of this Agreement and until all Services have been fully performed and completed, such insurance as a prudent supplier of systems management services in similar circumstances would maintain, based on factors including the availability of such insurance on commercially reasonable terms.

Such insurance shall include:

(a) commercial general liability insurance, written on an "occurrence" basis, including products and completed operations liability, contractual liability and personal injury, with a combined single limit of not less than Two

Million Dollars ($2,000,000) for each occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate involving bodily injury, death or property damage;

(b) crime and fidelity insurance in an amount not less than Two Million Dollars ($2,000,000) per occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate and covering all of ATCO I-Tek's Representatives for theft and fraud, including computer fraud, which results in loss to Client;

(c) to the extent reasonably available, data processing errors and omissions coverage with a combined single limit of not less than Two Million Dollars ($2,000,000) per loss or claim and not less than two million ($2,000,000) dollars (plus associated defence costs) in the aggregate;

(d) errors and omission insurance with a combined single limit of not less than Two Million Dollars ($2,000,000) per loss or claim and not less than two million ($2,000,000) dollars (plus associated defence costs) in the aggregate, protecting ATCO I-Tek and its Representatives against their legal liability for loss or damages arising out of the rendering or failing to render the Services;

(e) property insurance for the full replacement value of any ATCO I-Tek property located at Client's premises in ATCO I-Tek's possession or control;

(f) property insurance for the full replacement value of any Client property in ATCO I-Tek's possession or control;

(g) employer's liability insurance covering each worker of ATCO I-Tek to the extent of not less than Two Million Dollars ($2,000,000) where such worker is not covered by Workers' Compensation or where Workers' Compensation coverage is not the worker's exclusive remedy; and

(h) automobile public liability insurance covering all vehicles used to provide the Services, whether owned, operated and/or leased by ATCO I-Tek or its Representatives, with a combined single limit of Two Million Dollars ($2,000,000) for each occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate of bodily injury, death or property damage.

The insurance required under this Section 3.1 shall:

(i) name Client as an additional insured;

(j) provide a waiver of subrogation in favour of Client;

(k) require the insurer to provide ATCO I-Tek with no fewer than thirty (30) calendar days written notice prior to cancelling or effecting a material change to the policies; and

(l) be maintained in effect during the Term and any renewal term, provided that any policies written on a "claims made" basis shall be maintained for at least one (1) year following the expiry or termination of this Agreement, howsoever caused.

3.2 **Insurance Obligations of Client**

Client shall, at its own expense, obtain such insurance as is required to protect ATCO I-Tek and all assets of ATCO I-Tek that are at any time and from time to time on the premises of Client or the Work Location. Such insurance, which shall name ATCO I-Tek as an additional named insured, shall include:

(a) commercial general liability insurance, written on an "occurrence" basis, including products and completed operations liability, contractual liability and personal injury, with a combined single limit of not less than Two Million Dollars ($2,000,000) for each occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate involving bodily injury, death or property damage;

(b) crime and fidelity insurance in an amount not less than Two Million Dollars ($2,000,000) per occurrence and not less than ten million ($10,000,000) dollars (plus associated defence costs) in the aggregate covering all of Client's Representatives for theft and fraud, including computer fraud, which results in loss to ATCO I-Tek;

(c) property insurance for the full replacement value of any Client property located at ATCO I-Tek's premises in Client's possession or control;

(d) property insurance for the full replacement value of any ATCO I-Tek property in Client's possession or control;

(e) employer's liability insurance covering each worker of Client to the extent of not less than Two Million Dollars ($2,000,000) where such worker is not covered by Workers' Compensation or where Workers' Compensation coverage is not the worker's exclusive remedy.

The insurance required under this Section 3.2 shall:

(a) name ATCO I-Tek as an additional insured;

(b) provide a waiver of subrogation in favour of ATCO I-Tek;

(c) require the insurer to provide ATCO I-Tek with no fewer than thirty (30) calendar days written notice prior to cancelling or effecting a material change to the policies; and

(d) be maintained in effect during the Term, provided that any policies written on a "claims made" basis shall be maintained for at least one (1) year following the expiry or termination of this Agreement, howsoever caused.

ARTICLE 4
STATEMENTS OF WORK AND APPROVAL OF DELIVERABLES

4.1 Development of Statements of Work

Client shall initiate a request for Services by submitting a request thereof (the "**Request**") to ATCO I-Tek. The Request will describe the specific services that are required and any other relevant information needed to develop a Statement of Work in respect thereof. Upon receipt of the Request, ATCO I-Tek, in consultation with, and with the reasonable assistance of, Client, shall promptly prepare one or more draft Statements of Work (it being acknowledged that ATCO I-Tek may divide the work into phases or parts with each phase or part having a separate Statement of Work), which shall, as applicable:

(a) describe the Services to be performed by ATCO I-Tek and any services to be performed and items to be provided by Client;

(b) describe the roles and responsibilities of ATCO I-Tek and Client, and whenever possible name the Representative of each Party who shall be its contact person for the development of the Statement of Work (in each case, the "**Statement of Work Manager**");

(c) specify the Work Location(s) where the Services will be performed;

(d) set forth the credentials and skills of ATCO I-Tek's Representatives who will perform the services described in the Request;

(e) set forth the Commencement Date for the Services described in the Statement of Work and the period of time during which the Services will be provided there under;

(f) describe the Systems, equipment, scope and Deliverables to be provided during and at the completion of the Services;

(g) include a Schedule showing the estimated time frame for all stages of the Services;

(h) specify the estimated costs of the Services and the Schedule of payments to be made during and at the completion of the Services;

(i) describe the acceptance tests or means proposed for testing the Systems, equipment and Deliverables to be delivered during and at the completion of the Services; and

(j) specify such additional provisions as the Parties agree;

provided that ATCO I-Tek may, in its Discretion address Requests without a Statement of Work, it being acknowledged that certain Requests, typically of a minor or *de minimus* nature may be addressed in such fashion between the Parties.

4.2 **Requirement for Formal Execution**

No agreement shall be formed in respect of a Statement of Work until execution by both Parties of such Statement of Work in accordance with the provisions of this Agreement. Either Party may, at any time and without liability, withdraw from any negotiations related to any Request or draft Statement of Work.

4.3 **Approval of Deliverables**

To the extent that any Deliverable delivered to Client by ATCO I-Tek requires Client's approval under the terms of the relevant Statement of Work, Client will have ten (10) Business Days (or such other period as the Parties' respective Statement of Work Managers may agree in writing or as may be specified in the Statement of Work) (the "**Review Period**") after delivery thereof within which to approve or reject such Deliverable. If Client has a reasonable objection to any Deliverable, Client may reject the Deliverable. In such event, Client will deliver to ATCO I-Tek in writing within the Review Period the specific reasons for rejection and, where applicable, a single annotated copy of the Deliverable identifying required changes. ATCO I-Tek will make the appropriate corrections strictly in accordance with the Deliverable specifications in the Statement of Work. Client shall again be entitled to the Review Period to approve or reject the revised Deliverable. If Client does not expressly reject or approve a Deliverable or revised Deliverable, as the case may be, within the Review Period, the Deliverable in question shall be deemed approved.

Corrections to a Deliverable that is deficient because of ATCO I-Tek's omissions or errors or due to non-conformity with any applicable specifications provided to ATCO I-Tek as part of the applicable Statement of Work shall be made at the sole cost of ATCO I-Tek. The cost of corrections to a Deliverable occasioned by changes made to the Statement of Work by Client or costs incurred as a result of delays caused by Client (and provided such delays are not caused by or contributed to by ATCO I-Tek) shall be the responsibility of Client. If Client requires additional time to review any Deliverable provided to it under this Section for approval, ATCO I-Tek will cooperate with Client to extend the Review Period.

ARTICLE 5
PERSONNEL

5.1 General

(a) Client shall make available its personnel with such skills and expertise as may be necessary to coordinate and assist ATCO I-Tek in the provision of the Services.

(b) Subject to the balance of this Section 5.1, ATCO I-Tek shall be entitled to utilize any ATCO I-Tek Representatives in the provision of the Services but, unless otherwise specified herein, shall remain responsible for the performance by such Representatives of, and shall bind any such Representatives to, the obligations of ATCO I-Tek hereunder.

(c) ATCO I-Tek shall provide such Representatives who or which possess sufficient skill, knowledge, and training to perform the Services. The working hours and schedules of such Representatives shall be consistent with the local practice of the Work Location (as disclosed by Client to ATCO I-Tek prior to the commencement of the Services) and with applicable ATCO I-Tek employment policies and regulations, including those regarding sickness, disability, leaves of absence, holidays, vacations, seminars and off-site meetings ("**ATCO I-Tek Policies**"). ATCO I-Tek shall disclose all applicable ATCO I-Tek Policies to Client prior to the commencement of the Services. Following commencement of the Services, if ATCO I-Tek advises Client of other applicable Policies, or of any changes to ATCO I-Tek Policies disclosed to Client, and such Policies or changes thereto would impact the Schedule for the performance of the Services, then ATCO I-Tek shall provide additional resources as necessary to compensate. If such other or revised Policies will result in an increase in ATCO I-Tek's cost of performing its obligations under this Agreement, or would result in increased costs or expenses to Client, ATCO I-Tek shall be responsible for absorbing such additional costs.

(d) For further certainty, unless otherwise specifically agreed to in writing by ATCO I-Tek, ATCO I-Tek's Representatives shall work during Business Hours, and any Services required to be performed outside Business Hours shall be performed at an incremental cost provided that the additional cost is agreed to by Client.

5.2 ATCO I-Tek Designated Manager

ATCO I-Tek will designate a Representative (the "**ATCO I-Tek Designated Manager**") who will act as Client's primary point of contact and coordinate ATCO I-Tek's provision of the Services. ATCO I-Tek Designated Manager shall serve as the ATCO I-Tek contact person for Client. ATCO I-Tek shall provide a Designated Manager that is available for consultation with Client during Business Hours.

5.3 **Client Designated Manager**

Client will designate a Representative (the "**Client Designated Manager**") who will act as ATCO I-Tek's primary point of contact and coordinate ATCO I-Tek's provision of the Services. The Client Designated Manager shall be responsible for directing, insofar as ATCO I-Tek is concerned, all activities of Client affecting the provision by ATCO I-Tek of the Services.

5.4 **ATCO I-Tek Project Manager**

ATCO I-Tek will designate, with respect to each Statement of Work, a Representative of ATCO I-Tek (the "**ATCO I-Tek Project Manager**") who will act as Client's primary point of contact in dealing with ATCO I-Tek with respect to that particular Statement of Work. The ATCO I-Tek Project Manager for any Statement of Work may be the same person as the ATCO I-Tek Designated Manager, its Designated Representative and/or its Statement of Work Manager.

5.5 **Client Project Manager**

Client will designate, with respect to each Statement of Work, a Representative of Client (the "**Client Project Manager**") who will act as ATCO I-Tek's primary point of contact in dealing with Client with respect to that particular Statement of Work. The Client Project Manager shall be responsible for directing, insofar as ATCO I-Tek is concerned, all activities of Client affecting the provision by ATCO I-Tek of the Services pursuant to such Statement of Work. The Client Project Manager for any Statement of Work may be the same person as the Client Designated Manager, its Designated Representative and/or its Statement of Work Manager.

5.6 **Selection of Representatives**

Each Party shall have the right to designate its Representatives who will act on its (the "**Designating Party's**") behalf under the terms and conditions set forth herein (the "**Designated Representatives**"), and to remove such Designated Representatives from time to time. Each Party (the "**Other Party**") reserves the right to not accept one or more of the Designating Party's Designated Representatives during the selection process, and shall have the right to require the Designating Party to remove a Designated Representative from the Other Party's premises, including the Work Location, if such Designated Representative is not performing his responsibilities in a competent manner and such performance adversely affects the Designating Party's performance of its obligations hereunder. Before removing one of its Designated Representatives, the Designating Party shall provide the Other Party with as much prior notice as practical, the Other Party acknowledging that prior notice may not be possible when a Designated Representative chooses to leave the employ of the Designating Party or where a Designated Representative is terminated by the Designating Party. If a Designated Representative is removed, the Designating Party shall take all reasonable steps to provide a smooth transition, with the least disruption to the Services and cost to the Other Party reasonably possible in the circumstances.

5.7 **Replacement Representatives**

In circumstances where the provision by ATCO I-Tek of the services of an ATCO I-Tek Representative is charged to Client on an hourly basis or at the Time and Materials Rate, and ATCO I-Tek wishes to remove such ATCO I-Tek Representative from the performance of Services, ATCO I-Tek shall provide a replacement ATCO I-Tek Representative of suitable skill, knowledge, and training. Client will not be charged for any time or costs required to effect a transition to a temporary or permanent replacement, including time spent by the replacement ATCO I-Tek Representative to acquire knowledge of any Systems being maintained or services previously being provided by the replaced ATCO I-Tek Representative. If an ATCO I-Tek Representative is removed, ATCO I-Tek shall use reasonable commercial efforts to allow for the least disruption reasonably possible in the circumstances to the services previously being provided by the replaced ATCO I-Tek Representative.

5.8 **Cooperation in Replacement of ATCO I-Tek Representatives**

Client shall cooperate with ATCO I-Tek in making replacements and substitutions of ATCO I-Tek's Representatives, as provided in Section 5.7 (Replacement Representatives), in an orderly fashion.

5.9 **Compliance With Policies**

Each Party (the "**Accessing Party**") shall require all of its Representatives, when performing Services or otherwise attending at the premises of the other Party (the "**Granting Party**"), to comply with such other Party's applicable and lawful policies and regulations of which the Accessing Party is made aware, including those relating to security. The Granting Party shall disclose all its relevant policies and regulations prior to access being granted to the Accessing Party and its Representatives and, if applicable, prior to the Parties reaching agreement on the costing of particular Services. If a Representative of the Accessing Party violates a material policy or regulation of the Granting Party (as determined by the Granting Party, acting reasonably) or if a Representative of the Accessing Party repeatedly violates one of the Granting Party's non-material policies or regulations of which the Accessing Party or such Representative is made aware, the Granting Party may reject the Accessing Party's Representative for cause stated in writing to the Accessing Party, in which event the Accessing Party shall endeavour to replace the Representative in accordance with Section 5.10 (Reliance) below. If, following commencement of the relevant Services or access to the Granting Party's premises, as the case may be, the Granting Party advises the Accessing Party of other policies or regulations, or of any changes to policies and regulations previously disclosed to the Accessing Party, and such policies or regulations or changes thereto would impact the Schedule for the performance of the Accessing Party's obligations under this Agreement or would result in an increase in the Accessing Party's cost of performing its obligations under this Agreement, the provisions of Section 2.9 (Changes in Services) shall apply. Any conflict between the policies of the Accessing Party and those of the Granting Party shall be resolved using the dispute resolution procedure set forth in Article 16 (Dispute Resolution). Client Designated Manager will be available for

consultation during Business Hours and will have authority to make decisions and commitments on the part of Client.

5.10 **Reliance**

Each Party shall have the right to rely upon the instructions and decisions received from the other Party's Designated Manager or Project Manager, as the case may be, with respect to all matters relating to this Agreement or any Statement of Work, as applicable.

ARTICLE 6
CLIENT RESPONSIBILITIES

6.1 **General**

Client shall provide such cooperation, information and assistance as described in this Agreement or as may be reasonably requested by ATCO I-Tek to enable ATCO I-Tek to provide the Services. Client shall also be responsible for, on an ongoing basis during the Term and any renewal term:

(a) providing ATCO I-Tek with written feedback and/or commentary on the provision of the Services, including areas of concern to Client,

(b) providing management direction and decisions,

(c) making available for reference and use by ATCO I-Tek all required data, documentation, materials, systems and information,

(d) providing to ATCO I-Tek complete, accurate and current information on the Services required by Client, and

(e) achieving the specific business results or objectives,

all as specified or contemplated to be provided, made available, described or achieved by Client under this Agreement or as otherwise agreed on by the Parties, to enable ATCO I-Tek to provide the Services.

6.2 **Workspace in Client Work Location**

In connection with any Services to be performed by ATCO I-Tek at a Work Location owned or controlled by Client (including Tier 2 Services, Tier 3 Services and any support or maintenance services), Client shall provide reasonable working space for ATCO I-Tek's Representatives, which working space shall include working space for any ATCO I-Tek equipment required to be installed at a Work Location in order to provide the Services, telecommunications access, computer equipment, office equipment, and an adequate environment for same. The working environment provided by Client shall be safe and comply with Applicable Law.

6.3 **Client Data**

Client agrees to provide all necessary Client Data in a format as described in this Agreement (or as agreed to by the Parties in writing) and to take commercially reasonable steps to ensure the accuracy, legibility and completeness of all Client Data. Client shall be responsible to ATCO I-Tek for charges associated with any additional services that ATCO I-Tek must provide to Client as a result of Client's failure to provide accurate Client Data in the format or at the times agreed to by the Parties, or for any other errors or deficiencies in the Client Data.

6.4 **ATCO I-Tek Systems**

Client shall be responsible for maintaining the confidentiality and use of user identifiers and passwords provided by ATCO I-Tek for the purpose of accessing ATCO I-Tek Systems. Client shall take commercially reasonable steps to prevent Client's Representatives from interfering with, damaging or engaging in unauthorized use of ATCO I-Tek Systems.

6.5 **Consents**

Client shall be responsible for obtaining, at its sole expense, all necessary consents (whether required at the Commencement Date or at a future date) required to transfer any System, or part thereof, to ATCO I-Tek, or permit ATCO I-Tek and its Representatives to use or access any Systems, or part thereof, owned by or licensed to Client, which use or access is required in order to provide the Services, provided that ATCO I-Tek shall be entitled, upon request, to participate in applying for and reviewing such consents.

6.6 **Workload Planning**

Client acknowledges that it will be required to provide workload planning information as input to the development of each Annual Review (as hereinafter defined). Client will prioritize workload requirements such that hours allocated are used to meet appropriate business requirements. ATCO I-Tek will provide the personnel to deliver 25,000 hours of Development/Enhancement ("**D/E**") per year, balanced across the year, the applications portfolio and the ATCO Utilities. These D/E hours exclude large projects and will have billable rate as set out in Schedule D (Pricing). Usage in excess of this block of hours will be billed at the Time and Materials Rate.

ARTICLE 7
REVIEWS

7.1 **Periodic Reviews of Statements of Work**

Upon the request of, and with a frequency reasonably directed by Client, ATCO I-Tek Designated Manager shall make a presentation to Client Designated Manager on the status of all Statements of Work then under way by ATCO I-Tek.

7.2 **Annual Planning Reviews**

Annually, ATCO I-Tek shall provide Client with recommendations for changes to service measures, pricing and/or Services ("**Annual Review**"). ATCO I-Tek will work with Client to complete each Annual Review during the planning cycle (third quarter) of Client's fiscal year. As part of each Annual Review:

(a) ATCO I-Tek shall provide Client with:

(i) a report of the Services performed during the twelve (12) month period immediately preceding the last completed month of the Services;

(ii) a report that provides a breakdown of the Services performed in terms of base services (unit prices and volumes) and services incremental to base services related to Client requests including those related to growth and/or Change in Law, (incremental volumes, new unit prices, as appropriate); and

(iii) a list of standards and processes for the evaluation and selection of Systems required to be used in providing Services, and of the provision of Services.

(b) Client shall provide ATCO I-Tek with:

(i) a summary of any potential Statements of Work expected during the twelve (12) month period commencing from the next anniversary of the Effective Date,

(ii) volume forecasts (base volumes and volumes resulting from expected growth or Change in Law requirements; and

(iii) potential service change requests or new service requirements

After the exchange of such information, ATCO I-Tek and Client shall meet to assess the Services provided during the twelve (12) month period immediately preceding the last completed month of the Services, to revise Schedule B (Definition of Services) as necessary and to jointly develop a mutually agreeable information technology plan for the twelve (12) month period commencing on the next anniversary of the Effective Date, which plan (the "**IT Plan**") will include an operational component and a longer-term strategy component.

7.3 **Price Reviews**

Once during the Term and commencing no earlier than thirty (30) months after the Effective Date, Client will request that a benchmarking study be performed by an independent third party (a "**Benchmarker**") with the characteristics noted in Schedule G (Benchmarking Terms of Reference) to compare the quality and price of all of the

Services against the quality and price of other well-managed providers performing similar services to provide assurance that Client is receiving from ATCO I-Tek pricing and levels of service that are competitive with market rates, prices and service levels, given the nature, volume and type of services provided by ATCO I-Tek for a representative measurement period (typically one month) on an Aggregate Volume basis ("**Benchmarking**"). The Benchmarker may be hired and Client may provide the Benchmarker with instructions and information prior to the thirtieth (30^{th}) month after the Effective Date. Any such Benchmarking may not commence earlier than thirty (30) months after the Effective Date. In making this comparison, the Benchmarker shall consider such factors as the Benchmarker typically considers in its benchmarking methodology, including but not limited to the following factors and adjust the prices as and to the extent as defined in the report or result of Benchmarking or otherwise as appropriate: (i) any financial engineering, such as whether provider transition charges are paid by the customer as incurred or amortized over the Term; (ii) the extent to which this Agreement calls for ATCO I-Tek to provide and comply with unique Client requirements; (iii) whether service taxes are included in such pricing or stated separately in provider invoices; (iv) nature, size, scope and term of the contract, and (v) service locations.

General. Any Benchmarker engaged to perform the Benchmarking shall execute a non-disclosure agreement with Client and ATCO I-Tek and must be independent of both Client and ATCO I-Tek (without any conflict of interest) and have recognized information technology industry expertise with benchmarking expertise (including methodology and data source experience), and must not be either a provider of similar services, direct Client competitor or a direct ATCO I-Tek competitor. Notwithstanding the foregoing, ATCO I-Tek hereby consents to Client's use of any Benchmarker listed in Schedule G (Benchmarking Terms of Reference) for the purposes of the defined Benchmark. Other than a Schedule G (Benchmarking Terms of Reference) Benchmarker, the Benchmarker list (including any revisions thereto) shall be mutually agreed to in writing by Client and ATCO I-Tek. The Benchmarker shall be engaged on terms consistent with this Section and Schedule G (Benchmarking Terms of Reference) and otherwise acceptable to Client. ATCO I-Tek and Client shall cooperate on a commercially reasonable basis with the Benchmarker and shall provide commercially reasonable access to any premises, personnel or documents and provide any commercially reasonable assistance required by the Benchmarker to conduct the Benchmarking, all at Client's and ATCO I-Tek's respective commercially reasonable cost and expense assuming the Benchmarking is conducted in accordance with this Agreement. The Benchmarking shall be conducted so as not to unreasonably disrupt ATCO I-Tek's operations under this Agreement.

Result of Benchmarking. If the Benchmarker finds that the charges paid by Client for all Services on an Aggregate Volume basis, in aggregate (having considered charges for all Services in aggregate and charges for each individual Service Category), are greater than the average of the prices charged by other well-managed providers for work of a similar nature, type and volume, the charges shall be adjusted to eliminate such variance at the aggregate level of all Services. On an Aggregate Volume basis, pricing may be rebalanced across all Services in order to eliminate such variance. Provided that the

Benchmarking study is completed and delivered to the Parties no later than March 1st of the year following the commencement of the Benchmarking, such adjustments shall become effective January 1st of the year following the commencement of the Benchmarking. In the event that the completion and delivery of the Benchmarking study is delayed and the delay is not principally attributed to ATCO I-Tek, then such adjustments shall become effective as of the first day of the next month following the month during which the Benchmarking study is completed and delivered to the Parties. ATCO I-Tek reserves the right to challenge the Benchmarker's report pursuant to the dispute resolution process described in Article 16 (Dispute Resolution). Any reversal of the Benchmarking findings will be effective retrospectively to the date any adjustments based on the reversed Benchmarking became effective. Regardless of the results and determination of the Benchmarking, whether as to the competitiveness of ATCO I-Tek's prices at any Service Levels or otherwise, Client shall not be required to accept or pay any increase in any fees or prices payable to ATCO I-Tek under this Agreement in response to a Benchmarking.

ATCO I-Tek Review and Dispute. Client shall provide ATCO I-Tek with a copy of the Benchmarker's report and ATCO I-Tek shall have fourteen (14) Business Days to review such report and contest the Benchmarker's findings. If the Parties are unable to agree upon the validity of such findings, the matter shall be resolved pursuant to the dispute resolution process set forth in Article 16 (Dispute Resolution). Reductions in ATCO I-Tek's charges shall be implemented effective as of January 1st of the year following the commencement of the Benchmarking.

ARTICLE 8
CHARGES AND PAYMENTS

8.1 Financial Responsibility

Client shall have financial responsibility for all costs and expenses related to each item which is to be provided by Client under this Agreement or for which financial responsibility is not expressly allocated to ATCO I-Tek under this Agreement. If requested by ATCO I-Tek, Client shall provide ATCO I-Tek with a deposit or other form of advance payment in respect of such costs and expenses. ATCO I-Tek shall have financial responsibility for all costs and expenses related to each item which is to be provided by ATCO I-Tek under this Agreement and for which financial responsibility is not expressly allocated to Client under this Agreement.

8.2 Charges

In consideration of the provision by ATCO I-Tek to Client of the Services, Client shall pay to ATCO I-Tek the charges set forth in Schedule D (Pricing) and/or in any applicable Statement of Work. Client shall also pay all of ATCO I-Tek's charges with respect to any services other than the Services, including those referred to in Section 2.6 (Other Services).

8.3 **Price Adjustments**

(a) The unit prices set out in Schedule (D) (Pricing) establish the base unit charges for each year of the Agreement. ATCO I-Tek will adjust these charges on each anniversary of the Effective Date in accordance with the application of adjustments to the labour component of charges. Adjustments to labour charges or the labour components of services will be at the same percentage as any relevant adjustments described in the Wynford Group Survey for Alberta, provided that, if the Wynford Group Survey for Alberta should no longer be published or should be substantially changed in content or format after the date of this Agreement, ATCO I-Tek and Client will substitute another comparable measure published by a mutually agreeable source.

(b) ATCO I-Tek may delay implementing any adjustment up to four (4) months pending completion of the Annual Review, provided that any adjustment implemented after completion of the Annual Review shall be retroactive to the last anniversary of the Effective Date.

(c) The unit prices set out in Schedule D (Pricing) are based on the historical level of Services required by the ATCO Utilities and is referred to as the base volumes. Changes to the base volumes will be driven by changes in the ATCO Utilities businesses or Change in Law. In the case of an Extraordinary Event, if the actual or expected volume changes or is expected to change as compared to base volumes by more than fifteen percent (15%) over three (3) consecutive months, ATCO I-Tek and Client will meet to determine the impact to base unit pricing within a reasonable time. During any annual period, increases or decreases resulting from Client's actual volumes will be reflected in ATCO I-Tek's monthly billing, subject to the bandwidth described in Schedule D (Pricing) for each category.

8.4 **Expenses**

Client will reimburse ATCO I-Tek for reasonable out-of-pocket expenses incurred by ATCO I-Tek in connection with its performance under this Agreement (including travel and travel-related expenses) at the request and with the prior approval of Client.

8.5 **Specified Expenses**

Client shall be responsible for payment of all charges described as a "**Specified Expense**" on any Schedule. Any Specified Expenses paid by ATCO I-Tek as requested or directed by Client shall be billed at the actual Third Party cost as a flow through to Client.

8.6 **Additional Expenses**

If Client fails, or its Representatives fail, to comply with any of its or their obligations hereunder, and such failure is not due to a failure of ATCO I-Tek or ATCO I-Tek's Representatives, then:

(a) if such failure of Client or its Representatives can be reasonably expected to result in ATCO I-Tek being unable to perform its obligations in accordance with this Agreement, ATCO I-Tek shall be released from responsibility for such inability to perform for the period and to the extent that is justified by Client's or Client's Representatives' failure;

(b) if such failure can be reasonably expected to result in ATCO I-Tek incurring additional expenses, Client shall compensate ATCO I-Tek to the extent of such expenses, provided such expenses are reasonable in the circumstances. Such expenses shall be added to any invoices issued by ATCO I-Tek to Client hereunder; and

(c) ATCO I-Tek shall invoice Client the amount of such expenses, which invoice shall be due and payable upon receipt, provided that if Client, acting reasonably, disputes any portion of such invoice, it shall pay ATCO I-Tek only the undisputed portion thereof and may withhold the balance following resolution of the Dispute in accordance with Article 16 (Dispute Resolution).

If, through ATCO I-Tek's negligence, it fails to comply with any of its obligations, and such failure is not due to a failure of Client or Client's Representatives, and if such failure can be reasonably expected to result in a delay or interruption of the Services and in Client incurring additional expenses, ATCO I-Tek shall compensate Client to the extent of such expenses, provided such expenses are reasonable in the circumstances. Client shall invoice ATCO I-Tek the amount of such expenses, which invoice shall be due and payable upon receipt, provided that if ATCO I-Tek, acting reasonably, disputes any portion of such invoice, it shall pay Client only the undisputed portion thereof and may withhold the balance following resolution of the Dispute in accordance with Article 16 (Dispute Resolution).

8.7 **Taxes**

Client shall pay all taxes (including sales, use, consumption, value added, goods and services and similar taxes), duties, rates and levies of any nature whatsoever arising out of or in respect of this Agreement or the Services, excluding taxes on ATCO I-Tek's net income, any gains on capital of ATCO I-Tek, and payroll taxes/deductions in respect of ATCO I-Tek's Representatives. Where ATCO I-Tek pays such taxes, duties, rates or levies, or is obligated to collect the same, the same shall be added to any invoices issued by ATCO I-Tek hereunder.

8.8 **Payment for Services**

All charges for Services performed by ATCO I-Tek which are to be paid on a periodic or recurring basis, as identified in any Schedule, shall be payable by Client monthly in arrears. Charges will be calculated on a calendar month basis and will be prorated for any partial month. Unless otherwise agreed to by the Parties in writing, all charges for any other Services (including Tier 2 Services where a payment Schedule is not set out in

the applicable Statement of Work) and for expenses incurred pursuant to Sections 8.4 (Expenses) or 8.5 (Specified Expenses) shall be invoiced by ATCO I-Tek following the end of the month in which such Services are performed or expenses incurred.

8.9 **Invoices**

(a) Except where provided otherwise herein, ATCO I-Tek shall invoice Client monthly. Invoices shall be prepared and sent by ATCO I-Tek to Client by the seventh (7th) Business Day following the month in which the Services are provided or charges were otherwise incurred. All invoices shall be accompanied by supporting information and documentation and are due and payable upon receipt.

(b) If Client fails to pay any charges within forty five (45) days of the date of the relevant invoice, then ATCO I-Tek shall have the option to:

(i) charge Interest on such unpaid charges from the date that is forty five (45) days following the date of the invoice until the date that payment is received by ATCO I-Tek; and

(ii) charge Client for ATCO I-Tek's costs of collecting all past due amounts, including reasonable legal fees and disbursements on a solicitor and own client basis.

(c) Invoices shall be forwarded to the address and person identified in the relevant Schedule or Statement of Work.

(d) In the event that Client, acting reasonably, disputes any portion of an invoice, it shall pay ATCO I-Tek all amounts not in dispute and may withhold the amount in dispute pending resolution of the Dispute in accordance with Article 16 (Dispute Resolution). If Client is ultimately found liable for payment of the disputed amount, Client shall pay the disputed amount together with Interest on the disputed amount from the date the amount would have otherwise been subject to payment of Interest to the date on which payment is received by ATCO I-Tek.

(e) ATCO I-Tek will work with Client to design the form of invoice and specify the required supporting information relating to the Services and applicable charges so that Client will have sufficient detail about the charges to enable it to charge its clients for their share of the charges, if any.

ARTICLE 9
REPRESENTATIONS, WARRANTIES AND COVENANTS

9.1 **Mutual Representations, Warranties and Covenants**

Each Party represents, warrants and covenants to the other that:

(a) it is a corporation duly incorporated or organized, validly existing and in good standing under the Laws of its place of incorporation or registration, is properly qualified where qualification is necessary for the conduct of its business, and has adequate corporate or other power to enter into and perform this Agreement;

(b) this Agreement has been duly executed and delivered by such Party and (assuming the due authorization, execution and delivery hereof by the other Party) is a valid and binding obligation of such Party, enforceable against it in accordance with its terms;

(c) the execution and delivery of this Agreement and the performance by such Party of its obligations set forth in this Agreement are not limited or restricted by, nor do they conflict with, or violate, any Law, contract or other instrument to which such Party is a party or by which it is bound, nor do they or will they infringe or violate the rights of any Third Party;

(d) it is free, as of the date hereof, of any material contractual or statutory rights or obligations in favour of any Third Party that would prevent or impair it from entering into and fulfilling its obligations under this Agreement and, further, is unaware of any facts that would prevent it from performing its obligations under this Agreement; and

(e) it is not a non-resident of Canada for purposes of the *Income Tax Act* (Canada), and will provide prior written notice to the other Party of any change in its status in such regard;

(f) the obligations of it (the "**IP Indemnitor**") under this Agreement and

(i) in the case of ATCO I-Tek, the provision of the Services and any Deliverables (excluding any Third Party components), and

(ii) in the case of Client, any Systems, data, software, material or other content provided to ATCO I-Tek for use in providing the Services or any Deliverables,

shall be free of any claim of any Third Party for infringement of any IP Rights.

9.2 **Representations, Warranties and Covenants of ATCO I-Tek**

ATCO I-Tek represents, warrants and covenants that:

(a) the Services will be performed in a conscientious, diligent and efficient manner by competent personnel, and will be carried out in accordance with standards of care practiced by leading national and international suppliers of services that are the same or comparable to the Services;

(b) all electrical equipment installed by ATCO I-Tek at Client's premises shall be approved by the Canadian Standards Association or by the applicable provincial electrical authority;

(c) it shall take all reasonable steps and utilize reasonable commercial means and practices, in keeping with current available technology and, as set out in Schedule B (Definition of Services), to detect and, if practical, eliminate any routines, programs or devices, including those commonly referred to as computer viruses, worms and Trojan horses ("**Computer Viruses**"), in ATCO I-Tek Systems or in any electronic data introduced into Client Systems, or which could otherwise interfere with the performance of the Services; and

(d) it shall use commercially reasonable efforts for ATCO I-Tek Systems to exhibit Date Compliance, when used in accordance with its associated documentation, provided that all Systems used with ATCO I-Tek's Systems are date compliant and properly exchange accurate date data with it.

9.3 **Representations, Warranties and Covenants of Client**

Client represents, warrants and covenants that:

(a) it shall take all reasonable steps and utilize reasonable commercial means and practices, in keeping with current available technology, to detect and, if practical, eliminate any Computer Viruses in Client Systems, in any electronic data introduced into ATCO I-Tek Systems, or which could otherwise interfere in the performance of the Services;

(b) it shall communicate to ATCO I-Tek as soon as practical after the execution of this Agreement the Date Compliance of, any date compliant problems with, and any other defects, deficiencies or faults known to Client in, all Client Systems and any Systems transferred from Client to ATCO I-Tek under this Agreement or any asset transfer agreement which relates to this Agreement; and

(c) it has the right to deliver the Client Data to ATCO I-Tek and to permit ATCO I-Tek to use the Client Data and the Client Systems as contemplated herein.

9.4 **Limited Warranties**

The representations, warranties, covenants, terms or obligations provided in this Agreement are exclusive and are in lieu of any other understandings, representations, warranties, covenants, conditions, promises, guarantees or agreements, whether express, implied, statutory or otherwise, and whether arising from a course of dealing or usage of trade, relating to the Services or any Deliverables, including any warranty of merchantability or fitness or adequacy for any particular purpose or use, or of quality, productiveness, capacity or accuracy and only the express terms and conditions contained

in this Agreement shall be binding upon ATCO I-Tek and Client. The Parties agree, accept and confirm that all such other representations, warranties, conditions, covenants, provisions and guarantees are expressly denied and disclaimed, and that such denial and disclaimer is fair and reasonable in the circumstances of this Agreement.

ARTICLE 10
INDEMNITIES

10.1 Cross Indemnity

Each of ATCO I-Tek and Client (the "**Indemnitor**") agrees to indemnify, defend and hold harmless the other, including its Indemnified Persons (the "**Indemnitee**"), from any and all Claims arising out of the negligence or wilful act or omission of the Indemnitor resulting in injuries, including the death or bodily injury of any Representative, client, business invitee or business visitor of the Indemnitee, or loss or destruction of any real or tangible personal property of the Indemnitee, or arising out of such Party's failure or the failure of its Representatives to comply with the Applicable Law, including any additional costs for Services that must be re-performed as a result, provided, however, that this indemnity will not apply unless the Indemnitee notifies the Indemnitor promptly of any matters in respect of which the foregoing indemnity may apply and of which the Indemnitee has knowledge, and gives the Indemnitor full opportunity to control the response thereto and the defence thereof, including any agreement relating to the settlement thereof.

10.2 Client's Indemnity

Without restricting the generality of Section 10.1 (Cross Indemnity), Client specifically agrees to indemnify, defend and hold harmless ATCO I-Tek and its Indemnified Persons from any and all Claims arising in connection with the loss or theft of, or damage to, any of ATCO I-Tek's equipment, including all charges incurred by ATCO I-Tek in respect of financing and carrying costs, as well as from any and all Claims of whatsoever nature caused by or arising out of Client's failure to obtain the consents contemplated by Section 6.5 (Consents) and the permits contemplated by Section 2.7 (Compliance with Applicable Law).

10.3 Intellectual Property Indemnity

The IP Indemnitor shall, if notified promptly in writing, and given authority, information and assistance, by the other Party, defend, indemnify and hold harmless the other Party (including any Indemnified Persons) (the "**IP Indemnitee**") from any Claim against the IP Indemnitee based on a claimed infringement that constitutes a breach of the warranty in Section 9.1(f) (Representations, Warranties and Covenants). The IP Indemnitee shall promptly notify the IP Indemnitor of any such Claim, and the IP Indemnitor shall be given the opportunity to lead the defense or settlement of such Claim upon it acknowledging in writing ("**Acknowledgment**") to the IP Indemnitee that the IP Indemnitor is obligated to indemnify the IP Indemnitee. If the IP Indemnitor does not provide an Acknowledgement to the IP Indemnitee within fifteen (15) days of receiving

notice of the Claim from the IP Indemnitee, the IP Indemnitee may carry on the defence of such claim, and the IP Indemnitor shall thereafter be entitled only to participate in the defence or settlement of such Claim.

10.4 **Settlement of Claims**

Neither Party shall settle any Claims that are subject to the indemnification provisions hereunder without the prior written consent of the other Party, which consent may not be unreasonably withheld, conditioned or delayed.

ARTICLE 11
REMEDIES AND LIMITATIONS

11.1 **Accuracy and Reliability**

ATCO I-Tek shall make commercially reasonable efforts to provide the consistency, timeliness, accuracy and reliability of the Services and the Deliverables. However, Client acknowledges that ATCO I-Tek will not be held liable for any Claims of whatsoever nature arising out of any fault, interruption, or delay in providing, or inaccuracy or unreliability in, the Services or the Deliverables, except as

(a) provided in Section 2.8 (Service Credits),

(b) result from any inaccuracies, errors or omissions in the information provided by ATCO I-Tek to Client in connection with the Services, or

(c) are due to ATCO I-Tek's wilful misconduct.

11.2 **Limits on Liability; No Consequential Damages**

Notwithstanding any other provision of this Agreement to the contrary:

(a) ATCO I-Tek's liability to Client for all Claims, whether based in contract (including fundamental breach), warranty or tort (including negligence), or otherwise arising out of or relating to this Agreement shall not in the aggregate exceed the total charges paid by Client to ATCO I-Tek under this Agreement (excluding Specified Expenses, pursuant to Section 8.5 (Specified Expenses), and taxes, pursuant to Section 8.7 (Taxes)) for the Services performed during the three (3) month period preceding the event giving rise to the first Claim, regardless of the number of Claims; and

(b) neither Party shall in any event be liable to the other Party for any indirect, incidental, consequential or punitive damages arising out of or in connection with the delivery, use, performance or failure of the Services or any Deliverables or Systems, or any breach of this Agreement (including fundamental breach), or the negligence of that Party or its Indemnified Persons, even if advised of the possibility of such damages.

11.3 **Exclusions from Limits on Liability**

The limitations contained in this Article 11 shall not apply to any:

(a) unauthorized disclosure of Confidential Information by either Party;

(b) breach of warranty relating to IP Rights;

(c) breach by ATCO I-Tek or Client of an indemnity or other requirement to indemnify Client or ATCO I-Tek, respectively, for IP Rights infringement; and

(d) claims for personal injury or death or damage to real or tangible personal property to the extent caused by the negligence of the non-claiming Party.

11.4 **No Claim Against Certain Third Parties**

Client agrees that it will not Claim against any other client of ATCO I-Tek for losses suffered by Client in connection with this Agreement.

11.5 **Allocation of Risk**

The provisions of this Article 11 allocate the risk under this Agreement between Client and ATCO I-Tek. ATCO I-Tek's pricing reflects this allocation of risk and the limitation of liability specified herein.

11.6 **Not Penalty/Liquidated Damages**

All compensatory obligations and other remedies (whether financial or otherwise) expressly provided in this Agreement shall not constitute, nor are they intended by either Party to be, penalties or to be punitive against ATCO I-Tek. Both Parties agree and confirm that all such remedies are liquidated damages to compensate Client for losses and damages that will immediately be incurred by Client in the event of such breaches of this Agreement that are not possible to quantify or empirically determine, and that the remedies constitute a fair and reasonable estimate of the proximate and direct harm, loss and damage that Client shall suffer and incur in any such occurrence. ATCO I-Tek and Client agree and acknowledge that the remedies are justified, necessary and reasonable in the commercial and international circumstances of this Agreement, and that all such remedies constitute a material inducement for Client to enter into this Agreement.

ARTICLE 12
RECORDS, AUDITS AND SECURITY

12.1 **Maintenance and Inspection of Records**

ATCO I-Tek will maintain, in accordance with generally accepted accounting principles, all records and documents relating to the Services as are reasonably necessary to enable

Client to verify that Services are being performed in accordance with this Agreement and Applicable Law. ATCO I-Tek shall also maintain proper time sheets, accounts, records and invoices relating to all Services provided on a time and materials basis, and all expenses incurred by ATCO I-Tek for which Client is required to reimburse ATCO I-Tek. The foregoing records and documents shall be available, upon reasonable notice, for review and inspection by authorized Representatives of Client during the Term and for a minimum of (2) years following termination, or such time period as may be required pursuant to any Applicable Law or under the terms of any contract to which Client is subject, as ATCO I-Tek is notified from time to time by Client.

12.2 **Inspections and Audits**

(a) Upon fifteen (15) Business Days notice, Client and its auditors shall be entitled, at Client's cost and expense, under strict terms of confidence and subject to Applicable Laws, and in accordance with ATCO I-Tek's security procedures, during Business Hours, to audit the Client Data and escorted access to ATCO I-Tek's facilities (including any Work Location within the control of ATCO I-Tek where Client Data is processed or stored) and the records and documents described in Section 12.1 (Maintenance and Inspection of Records), to the extent necessary to verify:

(i) the accuracy of the charges and any reimbursable expenses;

(ii) that the security procedures and standards of care being practiced by ATCO I-Tek are consistent with its obligations under this Agreement;

(iii) that the Services are being provided in accordance with this Agreement; and

(iv) that the reporting of Service Levels complies with Schedule C (Service Measures);

provided any such access does not unduly interfere with ATCO I-Tek's ability to perform the Services or provide services to other clients. ATCO I-Tek shall also provide Client and its auditors with escorted access to ATCO I-Tek's computing facilities, Work Locations, and any other location where Client Data is processed or stored, as may be required by any regulatory authority, provided that Client shall use commercially reasonable efforts to provide ATCO I-Tek with reasonable notice of any requirement for access, and further provided that any person seeking such access complies with ATCO I-Tek's security procedures. ATCO I-Tek shall provide such additional assistance as may be reasonably required in connection with the foregoing inspections and audits.

(b) ATCO I-Tek will not, however, allow Client access to:

(i) other data (including the data of other ATCO I-Tek clients); or

(ii) any proprietary data or Confidential Information of ATCO I-Tek or its suppliers; or

(iii) areas which do not form part of the computing facilities or Systems used by ATCO I-Tek to provide the Services.

12.3 **Internal Procedures of ATCO I-Tek**

Upon request by Client, and at least once in any calendar year, ATCO I-Tek will provide to Client and its auditors, certified copies of relevant excerpts from reports prepared by ATCO I-Tek's auditors to establish that the Information Technology General Controls procedures maintained by ATCO I-Tek with respect to the Services meet or exceed the relevant requirements set forth by the ATCO Group, as amended from time to time.

Each calendar year ATCO I-Tek will work with Client to review the audit plan and agree on the most efficient manner to meet the objectives of the audit plan. Any incremental audit requirements are subject to the Time and Materials Rate.

12.4 **Security Practices of ATCO I-Tek**

ATCO I-Tek will adhere to commercially reasonable security practices in the management of the computing environment. ATCO I-Tek shall progress such practices to reflect the requirements of any operational security procedure developed jointly by Client and ATCO I-Tek and, on an ongoing basis, as required, to adhere to standards of care practiced by leading national and international suppliers of systems management services. If deficiencies are identified by Client as a result of audits of the services within this Agreement, ATCO I-Tek shall implement such additional security practices as are consistent with the standards of care practiced by leading national and international suppliers of system management services. At Client's request, ATCO I-Tek will provide Client with all reasonable assistance in identifying, tracking and closing security loopholes. New security requirements will be managed through a Statement of Work.

12.5 **Charges Related to Records, Audits and Security**

In the event that activities performed in respect of Sections 12.1 (Maintenance and Inspection of Records) and 12.2 (Access to ATCO I-Tek Facilities) are materially disruptive to ATCO I-Tek's business or are requested without reasonable notice or otherwise exceed commercially reasonable standards and levels, Client shall pay ATCO I-Tek, at the Time and Materials Rate, for such activities, except

(a) in respect of an inspection or audit once in every twelve (12) month period (from the Effective Date) during the Term, or

(b) if such inspection or audit reveals that ATCO I-Tek is in breach of its obligations under this Agreement,

in which case there shall be no charge to Client.

ARTICLE 13
OWNERSHIP

13.1 Client Data

ATCO I-Tek agrees that Client Data is, and shall remain, the exclusive property of Client at all times, and shall be held by ATCO I-Tek in trust for the sole benefit of Client. Client, its Representatives and Third Parties designated by it shall be permitted electronic access to all Client Data at all times, which access shall not be denied by ATCO I-Tek for any reason whatsoever (except when access is unavailable during reasonable periods of repair or maintenance), provided that such access must be exercised subject to the ATCO Group's security standards and such commercially reasonable terms and conditions imposed by ATCO I-Tek (including those relating to read-only access and the cost of access), as revised from time to time.

13.2 ATCO I-Tek Systems

ATCO I-Tek may process Client Data through Client Systems, ATCO I-Tek Systems and/or Systems of Third Party suppliers and may otherwise use the Client Data as required to provide the Services or as provided for in this Agreement. ATCO I-Tek Systems, including any associated IP Rights therein, are and shall remain the exclusive property of ATCO I-Tek and/or the Third Party licensors or suppliers of such Systems.

13.3 Client Systems

(a) Client Systems, including any associated IP Rights therein, are and shall remain the property of Client or the Third Party licensors or suppliers of such Systems. For any Client Systems owned by Client that will be used by ATCO I-Tek to provide the Services, Client grants to ATCO I-Tek the right to use such Client Systems solely in connection with the Services. For Client Systems licensed from Third Parties, Client will use all commercially reasonable efforts to obtain permission from the licensors of such Systems to permit ATCO I-Tek to operate such Systems, subject to the terms and conditions of the existing licenses and subject to the restriction that such Systems be used solely to permit ATCO I-Tek to provide the Services. ATCO I-Tek shall not:

(i) allow Client Systems to be disclosed, sold, assigned, leased, copied or otherwise disposed of or commercially exploited by ATCO I-Tek, its Representatives or Third Parties; and

(ii) use any Client Systems on its own behalf or on behalf of any unrelated Third Party without the prior written consent of Client, ATCO I-Tek shall not remove or destroy any markings or legends placed upon any Client System or documentation thereof, and shall reproduce such markings or legends if copies are made of Client Systems or such documentation. ATCO I-Tek further agrees to comply fully with any restrictions or obligations of which ATCO I-Tek is made aware, including any licensing

or nondisclosure obligations, imposed by any Third Parties on the use of Client Systems, and to execute such non-disclosure agreements as may be reasonably required by the Third Party licensors of Client Systems.

(b) If Client has been unable to obtain any one or more of the permissions contemplated by this Section 13.3 (Client Systems) or Section 6.5 (Consents) then, where reasonable in the circumstances and where deemed appropriate by Client, Client will either obtain substantially equivalent Systems or accept a reduction in Services to the extent necessary to reflect ATCO I-Tek's inability to use such Systems until permission is obtained. The applicable charges will be adjusted to reflect any reduction in Services.

(c) Unless Client otherwise agrees in a Statement of Work (complete and incomplete), Client shall own all new developments, Deliverables and/or know-how and all IP Rights therein (including without limitation, all new custom designed programs and all improvements, enhancements and modifications to existing or new custom designed programs and all new ATCO I-Tek software and all new improvements, enhancements and modifications thereto), which arise out of or are otherwise created during the course of or as a consequence of providing the Services; provided that, in respect of any particular new development, Deliverables, Client know-how and/or IP Rights, it was funded substantially by Client or by a combination of Client and one or more other utilities affiliated with Client. In all other cases, IP Rights shall vest with ATCO I-Tek. Each Party agrees to execute (and to obtain the agreement of its Representatives to execute) all additional agreements, instruments or documentation reasonably required to give effect to this provision.

13.4 **Documentation**

ATCO I-Tek will supply Client with such Documentation applicable to the Services as may be set out in a Schedule or Statement of Work. Any Documentation relating to ATCO I-Tek Systems and/or the Services, including any associated IP Rights therein, is and shall remain the exclusive property of ATCO I-Tek. ATCO I-Tek grants Client a limited, non-exclusive, non-transferable license to permit use by Client and its Representatives of such Documentation during the Term and any renewal term and in support of the provision of the Services. For further certainty, the foregoing does not apply to any Documentation produced as a Deliverable from Tier 2 Services, with the exception of any proprietary information of ATCO I-Tek contained in such Documentation.

13.5 **Prohibited Uses**

Client agrees it shall not, nor shall it permit any Third Party to, use Client's access to ATCO I-Tek Systems or any Documentation relating to Services or ATCO I-Tek Systems for the purpose of developing a competing System that is intended to provide functionality similar to ATCO I-Tek Systems and/or Services.

13.6 **ATCO I-Tek Know-How**

Client acknowledges that ATCO I-Tek, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, whether patentable or not, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms used in the provision of the Services hereunder or relating to the conduct or operation of its business ("**ATCO I-Tek Know-How**"). Client further acknowledges and agrees that such ATCO I-Tek Know-How constitutes confidential, valuable proprietary information and trade secrets of ATCO I-Tek or its suppliers and that ATCO I-Tek shall retain exclusive ownership of such ATCO I-Tek Know-How, including any applicable IP Rights therein.

13.7 **Client Know-How**

ATCO I-Tek acknowledges that Client, in the course of its business, has developed know how, ideas, techniques, concepts, devices, trade secrets, works of authorship, inventions, whether patentable or not, innovations or improvements in any device, process or thing, methodologies, processes, technologies and algorithms relating to the conduct or operation of its business ("**Client Know-How**"). ATCO I-Tek acknowledges and agrees that such Client Know-How constitutes confidential, valuable proprietary information and trade secrets of Client or its suppliers and that Client shall retain exclusive ownership of such Client Know-How, including any applicable IP Rights therein.

13.8 **IT Assets**

Notwithstanding anything else in this Agreement, all IT assets that are not expressly designated elsewhere in this Agreement or in a Statement of Work as belonging to Client shall belong to and remain the property of ATCO I-Tek.

ARTICLE 14
CONFIDENTIALITY, PUBLICITY

14.1 **Confidential Information**

Each of ATCO I-Tek and Client acknowledges that, in the course of providing or obtaining the Services, it and/or its Representatives (each a "**Recipient**", as applicable) may be supplied with, come into possession of, or have access to, information, material or data from the other Party ("**Disclosing Party**") which is designated as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure (the "**Confidential Information**"). Confidential Information of a Disclosing Party includes information owned by the Disclosing Party (or to which the Disclosing Party has rights of exclusion with respect to the commercial use of such Confidential Information):

(a) relating to the Disclosing Party's software or hardware products and services or to its research and development projects or plans, including, in the case of

ATCO I-Tek, ATCO I-Tek Know-How, Documentation and ATCO I-Tek Systems, and including, in the case of Client, Client Systems and associated documentation, Client Data and Client Know-How;

(b) relating to the Disclosing Party's trade secrets, business policies, strategies, operations, finances, plans or opportunities, including the identity of, or particulars about, same;

(c) relating to the Disclosing Party's clients or suppliers;

(d) that is marked or otherwise identified as confidential, restricted, secret or proprietary, including information made available to the Recipient for inspection or by oral disclosure, provided such information is identified as confidential at the time of disclosure or inspection and the Disclosing Party promptly provides the Recipient with written confirmation summarizing the confidential information disclosed; and

(e) disclosing the terms and conditions set forth herein.

Each Recipient agrees not to remove, cover, deface or alter any copyright, trade secret or trade mark notices contained on the Confidential Information.

14.2 **Confidentiality of Agreement**

Except where either Party is required to disclose any provision of this Agreement in order to exercise any right or to perform any obligation hereunder, and subject to any requirement for disclosure under any Applicable Law and to Section 14.5 (Permitted Disclosure), neither Party shall disclose the terms and conditions of this Agreement to any other person, unless expressly agreed by the other Party.

14.3 **Disclosure to Representatives**

Each Recipient agrees to disclose the Confidential Information only to those of its Representatives who have a need to know the Confidential Information, and who are under a written and enforceable obligation to keep confidential the Confidential Information received from the Disclosing Party and to use the Confidential Information only for the purposes described in this Agreement. Client Data shall not be used by ATCO I-Tek for any purpose other than to provide the Services to Client. Each Recipient will, prior to disclosing the information to its Representatives, advise them of its obligations under this Article 14. Upon request, each Recipient agrees to provide the Disclosing Party with a list of the Recipient's Representatives who have been provided with access to the Confidential Information of the Disclosing Party.

14.4 **Preventing Other Disclosure or Use**

Each Recipient agrees to make commercially reasonable efforts that the Disclosing Party's Confidential Information is not directly or indirectly disclosed to or used by any person except as provided for in this Agreement or as is expressly authorized in writing

by the Disclosing Party. Each Recipient's efforts will not be less than those which the Recipient takes or would be reasonably expected to take to prevent disclosure of its own Confidential Information of like significance.

Each Recipient shall notify each Disclosing Party promptly if the Recipient becomes aware or has reasonable grounds to suspect that unauthorized disclosure of Confidential Information of the Disclosing Party has occurred or is likely to occur. Each Recipient shall, at the request of each Disclosing Party and at each Recipient's own expense, use all reasonable efforts to assist the Disclosing Party in identifying any use, copying, or disclosure of any Confidential Information by any present or former Representative of the Recipient in any manner contrary to the provisions of this Agreement, provided that the Disclosing Party shall have provided the Recipient with information reasonably justifying the conclusion of the Disclosing Party that such contrary usage may have occurred.

14.5 **Permitted Disclosure**

Notwithstanding the foregoing, neither Party shall be obligated to comply with the above-mentioned obligations of this Article 14 relating to Confidential Information if such Confidential Information:

(a) was known to the Recipient at the time of disclosure, as evidenced by any written documents in the possession of the Recipient;

(b) is available to the general public at the time of disclosure to the Recipient, or is subsequently made available to the general public without fault of the Recipient;

(c) pertains to general industry knowledge, processes or techniques;

(d) is disclosed or becomes available to the Recipient by reason of any act of any Third Party or organization having the right to disclose or publicize it;

(e) is intentionally distributed, without restriction as to confidentiality, by the Disclosing Party;

(f) is required to be disclosed in connection with the conduct of any arbitration or court proceeding carried out pursuant to this Agreement, provided that such disclosure is made pursuant to, and in accordance with, the approval, and at the direction, of the arbitrators conducting such arbitration or applicable judicial officers, and further provided that both Parties hereto use commercially reasonable efforts to have such arbitrators execute confidentiality agreements, the terms of which are similar to those set out herein; or

(g) is required to be disclosed pursuant to a final order to disclose issued by a court of competent jurisdiction, a government agency or regulatory body, provided that the Recipient subject to such order provides to the Disclosing Party immediate written notification of any such requirement for disclosure,

and further provided the Recipient takes such steps as are reasonably necessary and available to maintain confidentiality by the court, government agency or regulatory body.

14.6 **No Breach for Use of General Knowledge**

Both Parties acknowledge and agree that their Representatives, during the course of performing or obtaining the Services, may develop their general knowledge, skills and experience as they relate to data processing. The subsequent use by either Party or its Representatives of such general knowledge, skills and experience relating to data processing in the ordinary course of business will not constitute a breach of the confidentiality provisions contained in this Agreement.

14.7 **Injunctive Relief**

Each Recipient acknowledges and agrees that any use or disclosure of Confidential Information of the Disclosing Party in a manner inconsistent with the provisions of this Agreement may cause the Disclosing Party harm which will not be compensable by monetary damages alone and, accordingly, each Disclosing Party will, in addition to other available legal or equitable remedies, be entitled to seek an immediate injunction restraining the Recipient and its Representatives from using or disclosing, or continuing to use or disclose, such Confidential Information. In such event, the Disclosing Party applying for injunctive relief need not show or prove any actual damage sustained by it and may avail itself of injunctive relief in addition, and without prejudice, to any other remedies available to it.

14.8 **Return of Information**

Promptly upon the termination of this Agreement, or such earlier date upon which Confidential Information of the Disclosing Party is no longer required by a Recipient for the purposes of this Agreement, the Recipient shall return the Confidential Information to the Disclosing Party and shall erase all copies of such Confidential Information in the possession or control of the Recipient or its Representatives.

14.9 **Publicity**

Each Party will submit to the other all advertising, sales promotion, press releases and other publicity materials relating to this Agreement in which the other Party's name or mark is mentioned or in which language is used, from which the connection of said name or mark may be inferred or implied. Neither Party will publish or use such advertising, sales promotion, press releases or publicity materials without the prior written approval of the other Party. However, either Party may include the other Party's name and a general factual description of the work performed under this Agreement in employee bulletin boards, lists of references, the experience Section of proposals to Third Parties, internal business planning documents and communications, and annual reports to shareholders, and whenever required by reason of legal, accounting or regulatory requirements.

ARTICLE 15
TERM AND TERMINATION

15.1 **Term**

This Agreement shall be in effect for a term ending six (6) years from the Effective Date (the "**Term**"), subject to earlier termination or renewal as hereinafter provided.

15.2 **Renewal**

Starting on the fourth anniversary of the Effective Date, the Parties will enter into negotiations regarding renewal of the Agreement for a new six (6) year term effective on the fifth anniversary of the Effective Date.

In the event that the preceding activity has not been undertaken and no later than eighteen (18) months prior to the end of the Term (or as soon thereafter as may be reasonably practical for ATCO I-Tek), ATCO I-Tek will send Client a notice (the "**Renewal Notice**") requesting that Client advise ATCO I-Tek if Client does not wish to renew this Agreement following the expiry of the Term. If Client does not respond in writing to the Renewal Notice within thirty (30) days following the date of the Renewal Notice, this Agreement will be automatically renewed for six (6) years on the fifth anniversary of the Effective Date on the same terms and conditions *mutatis mutandis*, including, without limitation, then prevailing pricing as adjusted through the Term and the obligations to review and/or adjust pricing all of which shall be applicable during the renewal term of the Agreement.

15.3 **Subsequent Renewals**

If this Agreement is renewed following the expiry of the Term, pursuant to Sections 15.2 (Renewal), the process set forth therein for renewal shall continue and shall apply to each renewal term.

15.4 **Triggering Events**

Each of the following events shall constitute a "**Triggering Event**" with respect to a Party for the purposes of Section 15.5(c) (Termination):

(a) a receiver (unless the receivership order is vacated within thirty (30) days), trustee of bankruptcy or any other similar officer (unless such officer's appointment is vacated within thirty (30) days) is appointed to take charge of all or any substantial part of the other Party's business or property;

(b) the other Party becomes an insolvent person or commits an act of bankruptcy within the meaning of those terms in the *Bankruptcy and Insolvency Act* (Canada);

(c) a petition is filed or any other action is taken with respect to the other Party for reorganization or for arrangement under any provision of the *Bankruptcy*

and Insolvency Act (Canada) or any similar Law then in force and providing a plan for a debtor to settle, satisfy or to extend the time for payment of debts;

(d) any application, petition, certificate or order is made or granted for the winding up or dissolution of the other Party, voluntarily or otherwise.

15.5 **Termination**

This Agreement may be terminated:

(a) at the expiry of the Term or any renewal term, as the case may be, if Client notifies ATCO I-Tek of Client's intention to terminate this Agreement, pursuant to Section 15.2 (Renewal);

(b) immediately upon giving notice by a Party not in breach if the other Party commits a Material Breach of this Agreement, as set out below;

(c) immediately upon giving notice if a Triggering Event occurs in respect of the other Party;

(d) by Client, for convenience, on ninety (90) days prior written notice any time after the first anniversary of the Effective Date upon payment to ATCO I-Tek of a termination charge equal in amount to the average monthly charge paid in the previous twelve (12) month period multiplied by three-quarters the number of months remaining in the Term or renewal term, as the case may be, (to compensate ATCO I-Tek for lost profits and the cost of reallocating resources);

(e) pursuant to Section 18.12 (Force Majeure).

For the purposes of this Agreement, either Party shall be deemed to be in Material Breach of this Agreement if it fails to perform any obligation hereunder which has a material adverse effect on the other Party, and such failure is not cured either within thirty (30) days following notice by the non-defaulting Party hereunder, or, if such failure is not capable of being reasonably cured within such thirty (30) day cure period, according to an action plan agreed upon by the Parties within thirty (30) days following notice, provided that, in the latter case, the Party attempting to effect the cure commences the cure within such thirty (30) day period and continues thereafter to diligently exert all reasonable commercial efforts to cure the failure.

15.6 **Effect of Termination**

(a) Subject to the Termination Transition Plan (Schedule F), upon termination of this Agreement for any reason all applicable Statements of Work shall also terminate.

(b) The Parties agree that, upon termination of this Agreement for any reason, Client shall remain liable to ATCO I-Tek for all charges that are to be paid by Client in accordance with the provisions of this Agreement.

(c) Upon any early termination of this Agreement by ATCO I-Tek pursuant to Section 15.5(b) or Section 15.5(c) (Termination), Client shall pay commercially reasonable compensation to ATCO I-Tek for any severance expenses, early termination expenses and other costs suffered by ATCO I-Tek for reallocating resources, effecting early termination of sub-contracts and supply arrangements.

(d) Upon any early termination of this Agreement by Client pursuant to Section 15.5(b) or Section 15.5(c) (Termination), ATCO I-Tek shall pay Client all commercially reasonable direct costs incurred by Client to transfer the provision of Services back to Client or their Third Party service provider, and, notwithstanding anything contained in Section 15.6(e) or Schedule F (Termination Transition Plan) to the contrary, ATCO I-Tek shall be responsible for all costs incurred by either ATCO I-Tek or Client in connection with items 1, 2, 5 and 7 of the Termination Transition Plan set out in Schedule F (Termination Transition Plan).

(e) Upon expiry or termination of this Agreement for any reason whatsoever, ATCO I-Tek shall, subject to the terms and conditions of this Section 15, and the limitations of ATCO I-Tek's liability set forth in Article 11 (Remedies and Limitations), provide transition services ("**Termination Transition Services**") to Client in accordance with Schedule F (Termination Transition Plan) ("**Termination Transition Plan**") for a period of up to a maximum of twelve (12) months after the date of such termination, or in the case of expiry of the Agreement, during the twelve month period prior to the expiry thereof ("**Transition Assistance Period**"). During the Transition Assistance Period, Client shall continue to pay all applicable fees to ATCO I-Tek for the Services, and any additional tasks performed by ATCO I-Tek, including the Termination Transition Services, shall be charged to Client at the Time and Materials Rate, or otherwise as agreed in a Statement of Work, including the Termination Transition Plan. ATCO I-Tek shall perform the Termination Transition Services in a timely, workmanlike, competent, conscientious and professional manner, in accordance with generally accepted standards of care in the energy industry.

ARTICLE 16
DISPUTE RESOLUTION

16.1 **Informal Review**

In the event of a Dispute, not subject to an exception pursuant to Section 16.4(Disputes Not Subject to Informal Review or Arbitration), the following dispute resolution procedure will be followed:

(a) **Level 1 Review** Upon the written request of either Party, each of the Parties will appoint a designated officer whose task it will be to meet for the purpose of endeavouring to resolve the Dispute or to negotiate for an adjustment to the provisions of this Agreement, including any affected Statements of Work. The designated officers will meet as soon as possible following either Party receiving notice of the Dispute, giving due regard to the nature and the impact of the Dispute, and as often thereafter as each Party reasonably deems necessary in order to gather and furnish to the other Party all information which the Parties believe to be appropriate and germane to resolution of the Dispute. Such designated officers will discuss the Dispute and use commercially reasonable efforts to negotiate a resolution to the Dispute and to renegotiate the applicable Section or provision of this Agreement, as required, without the necessity of any formal proceeding relating thereto. The specific format for such discussions will be left to the discretion of the designated officers but may include the preparation of agreed upon statements of fact or written statements of position, which shall be made on a "without prejudice" basis, furnished to the other Party. If the Dispute is not resolved within thirty (30) days of this Level 1 Review, or if both Representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either Party may escalate the Dispute to a Level 2 Review.

(b) **Level 2 Review** Each Party will appoint an executive officer to represent that Party in a negotiation to resolve the Dispute. If the Dispute is not resolved within thirty (30) days of the later of such appointments, or if both Representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either Party may escalate the Dispute to a Level 3 Review.

(c) **Level 3 Review** An executive officer of each Party will meet with a Representative of the ATCO Group's Office of the Chairman to resolve the Dispute. If the Dispute is not resolved within thirty (30) days of this Level 3 Review, or if both Representatives conclude that resolution of the Dispute through continued negotiations during this thirty (30) day period is not likely to occur, then either Party may commence formal proceedings for arbitration of the Dispute, as provided for in Section 16.2 (Arbitration).

16.2 **Arbitration**

Subject to Section 16.4 (Disputes Not Subject to Informal Review or Arbitration) or the Parties having unsuccessfully followed the dispute resolution process set out in Section 16.1 (Informal Review), any Dispute will be settled by arbitration conducted in accordance with the *Arbitration Act*, R.S.A. 2000, c. A-43, as amended from time to time (the "**Arbitration Act**"), by a board of arbitration (the "**Board**"). The Board, which shall conduct the arbitration in either Edmonton, Alberta or Calgary, Alberta, shall be appointed as follows:

(a) Subject to paragraph (2) hereof, the Board will be composed of one person appointed by the Party requesting resolution of the Dispute by the Board (the "**Applicant**"), one person appointed by the other Party (the "**Respondent**") and a third person to act as chairperson, chosen by the first two chosen members of the Board, provided that if both Parties agree, the Board will consist of a sole arbitrator appointed by both Parties.

(b) The Applicant shall deliver to the Respondent written notice of the Applicant's intent to refer the Dispute to the Board within one hundred (100) days after the failure of the Level 3 Review to resolve the Dispute, and shall, at the same time, name its appointee to the Board. The Respondent shall, within fifteen (15) Business Days of receipt of such notice, advise the Applicant, in writing, of the name of its appointee to the Board. If the Respondent fails to notify the Applicant of its appointee, the Respondent shall be deemed to have concurred in the appointment of the Applicant's appointee, and such appointee shall alone constitute the Board.

(c) If the Respondent appoints an arbitrator pursuant to paragraph (2) above, then, within five (5) Business Days of the appointment of such arbitrator, the two (2) appointed arbitrators shall agree on the appointment of a third arbitrator to act as chairperson (the "**Chairperson**"). If the appointed arbitrators cannot agree on the appointment of the third arbitrator, either the Applicant or the Respondent may apply to the Court of Queen's Bench of Alberta to appoint the third arbitrator, or promptly take such other action to appoint a Chairperson as the Parties may agree.

No decision of the Board shall be subject to appeal except as otherwise required by the Arbitration Act.

16.3 **Conditions Precedent to Commencing an Action or Proceeding**

Other than any action necessary to enforce the award of the Board, and subject to Section 16.4 (Disputes Not Subject to Informal Review or Arbitration), the Parties agree that exhausting the provisions of Sections 16.1 (Informal Review) and 16.2 (Arbitration) is a condition precedent to a Party's right to commence an action or proceeding in respect of a Dispute, and accordingly, subject to Section 16.4 (Disputes Not Subject to Informal Review or Arbitration), this Article 16 is a complete defence to any suit, action or other

proceeding instituted in any court or before any administrative tribunal with respect to any Dispute arising under or in connection with this Agreement. Notwithstanding the foregoing, nothing in this Article 16 prevents the Parties from exercising their rights to terminate this Agreement in accordance with its provisions.

16.4 **Disputes Not Subject to Informal Review or Arbitration**

The Parties acknowledge and agree that, with respect to any Dispute arising under Article 14 (Confidentiality, Publicity), to protect an IP Right, or in respect of a claim for injunctive relief, a Party may refer such matter to arbitration in accordance with this Article 16 or apply to the appropriate court for relief without having to first follow the other dispute resolution mechanisms set forth in this Article 16.

ARTICLE 17
NOTICE

17.1 **Notices**

(a) Unless otherwise specified herein or otherwise agreed by the Parties in writing, any notice required to be given hereunder must be given in writing and delivered by postage-paid mail, personally, by prepaid courier, by fax or by other electronic means, addressed to the appropriate Party at its address for notice set forth on the signature page of this Agreement.

(b) Any notice provided herein shall be deemed to have been given as follows:

(i) if delivered by mail, seventy-two (72) hours after the mailing thereof, Saturdays, Sundays and statutory holidays excepted, provided that if there shall be, prior to the time of mailing or the actual receipt of a notice, a threatened or actual postal strike or other interruption that might affect the delivery of the notice by mail, then such notice shall be delivered personally, by courier, by fax or by other electronic means;

(ii) if delivered personally or by courier before 2:00 p.m. (time of the recipient) on a Business Day, on that Business Day;

(iii) if delivered personally or by courier at or after 2:00 p.m. (time of the recipient) on a Business Day or on a day that is not a Business Day, on the next Business Day;

(iv) if sent by fax or other electronic means on a Business Day and the sending Party obtains confirmation that all of the pages of the notice have been successfully transmitted before 2:00 p.m. (time of the recipient), on that Business Day;

(v) if sent by fax or other electronic means on a Business Day and the sending Party obtains confirmation that all of the pages of the notice have been successfully transmitted, but that some or all of the pages of the notice were transmitted after 2:00 p.m. (time of the recipient), on the next Business Day;

(vi) if sent by fax or other electronic means on a day that is not a Business Day and the sending Party obtains confirmation that all of the pages of the notice have been successfully transmitted, on the next Business Day.

(c) Either Party hereto may, from time to time, give notice of a change in its address, contact person, fax number or other electronic address by notice as provided herein and, in that event, such information shall be deemed to be changed accordingly.

(d) Neither Party shall prevent, hinder or delay, or attempt to prevent, hinder or delay the service on that Party of a notice relating to this Agreement.

ARTICLE 18
GENERAL

18.1 Assignment

Neither Party shall assign this Agreement or any rights, benefits, warranties or obligations granted hereunder without the express written consent of the other Party, which consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, ATCO I-Tek may assign this Agreement to a corporate entity in the event of a transfer to that entity of all or substantially all of the assets of ATCO I-Tek used to provide the Services.

18.2 Non-Solicitation of Employees

(a) Except as otherwise agreed by the Parties in writing, for the Term, any renewal Term and for a period of one (1) year thereafter, neither Party will, directly or indirectly (including through a successor service provider used by Client), recruit, hire as an independent contractor or offer employment to any Representative of the other Party who is or was substantially involved in the delivery or receipt of Services without the prior written consent of the other Party or until a period of at least twelve (12) months has elapsed after such Representative's employment with the other Party has ended.

(b) In the event of a termination of the Agreement pursuant to subsection 15.5(b) or (c) hereof, ATCO I-Tek and Client will, as soon as reasonably possible, develop a written list of ATCO I-Tek employees that Client would propose to offer employment to. The Parties will have five (5) Business Days from the receipt by ATCO I-Tek of the list of employees to

agree whether such employees can be offered employment by Client. If no agreement is reached within such time period either Party may submit such dispute to dispute resolution in accordance with Article 16 (Dispute Resolution). For greater certainty, all ATCO I-Tek employees identified in the list of employees above shall continue in the employ of ATCO I-Tek until the dispute is resolved.

18.3 **Severability**

If any term or provision of this Agreement or the application thereof to any person or circumstances shall, to any extent, be deemed by a court of competent jurisdiction to be invalid or unenforceable, such term or provision shall be deemed severed from this Agreement, and the remainder of this Agreement or the application of such term or provision to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and shall be valid and enforceable to the extent permitted by Applicable Law.

18.4 **Independent Contractors**

The Parties acknowledge that they are independent contractors and that this Agreement shall not create a relationship of employment, partnership, or joint venture between the Parties or between one Party and the other Party's Representatives. Each Party specifically acknowledges that its Representatives are not employees, agents or partners of the other Party. Unless otherwise provided in this Agreement, each Party has the right and obligation to supervise, manage, contract, direct, procure, perform or cause to be performed all work to be performed by that Party under this Agreement. ATCO I-Tek may, from time to time, perform services similar to the Services for ATCO I-Tek's other clients.

18.5 **Governing Law**

This Agreement and any disputes, including Disputes, arising or resulting from the transactions contemplated under this Agreement shall be construed in accordance with and governed in all respects by the Laws of Alberta and the federal Laws of Canada applicable therein. Subject to Article 16 (Dispute Resolution), the Parties submit to the exclusive jurisdiction of the courts of Alberta.

18.6 **Survival**

Notwithstanding the termination of this Agreement for any reason, any obligations which by their nature are intended to survive such termination shall continue in full force and effect until discharge of the obligation or until the Parties mutually agree to a release of the obligation, which obligations shall include those pursuant to Sections 1.1 (Interpretation), 1.2 (Definitions), 3.2 (Insurance Obligations of Client) and 15.6 (Effect of Termination), and Articles 8 (Charges and Payments), 9 (Representations, Warranties and Covenants), 10 (Indemnities), 11 (Remedies and Limitations), 13 (Ownership), 14 (Confidentiality, Publicity), 16 (Dispute Resolution), 17 (Notice) and this Article 18 (General).

18.7 **Entire Agreement**

This Agreement constitutes the entire agreement between the Parties hereto pertaining to the subject matter of this Agreement, and supersedes all prior or contemporaneous agreements, understandings, representations, negotiations and discussions, whether oral or written, including letters of intent or other agreements of the Parties hereto including the MSA, and there are no warranties, representations or other agreements between the Parties hereto, implied or express, statutory or otherwise, in connection with the subject matter hereof except as specifically set forth herein. For further clarification, Client acknowledges and agrees that it is not relying upon any representation in any advertising, marketing material, catalogue or similar material provided to Client by ATCO I-Tek. In no case shall any printed terms and conditions on any standard transactional documentation of Client (including Client's form of purchase order) modify this Agreement or otherwise apply to ATCO I-Tek or the provision of the Services hereunder.

18.8 **No Waiver**

The observance of any term of this Agreement may be waived (either generally or in a particular instance, and either retroactively or prospectively) by the Party entitled to enforce such term, but such waiver shall be effective only if it is in writing and signed by the Party against which such waiver is to be asserted. Unless otherwise expressly provided in this Agreement, no delay or omission on the part of either Party in exercising any right or privilege under this Agreement shall operate as a waiver thereof, nor shall any waiver on the part of either Party of any right or privilege under this Agreement operate as a waiver of any other right or privilege under this Agreement, nor shall any single or partial exercise of any right or privilege preclude any other or further exercise thereof or the exercise of any other right or privilege under this Agreement.

18.9 **Enurement**

This Agreement shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

18.10 **Further Assurances**

The Parties agree to do or cause to be done all such further acts or things required to implement and carry into effect this Agreement to its full extent.

18.11 **Currency**

Unless indicated otherwise in a particular Schedule or Statement of Work, all amounts referred to herein are stated and shall be payable in Canadian funds.

18.12 **Force Majeure**

Except with respect to any payments required pursuant to this Agreement, neither Party hereto shall be liable to the other Party or considered to be in default under this Agreement for any delay or failure to perform its obligations hereunder due to an event of

force majeure, which shall include strikes, labour disputes, riots, explosions, earthquakes, acts of God, severe weather conditions materially preventing or impairing work, failure or fluctuations in electrical power, heat, light, air conditioning, water sprinklers, telecommunications equipment or lines, acts of any governmental authority, war, failure or delay of any Third Party supplier, unavailability or shortages of materials, equipment failures or, without limitation, any other cause or causes beyond the reasonable control of such Party and which could not have been reasonably foreseen and protected against. The Parties hereto shall use commercially reasonable efforts during the Term to avoid or, if unavoidable, minimize the effects of any event of force majeure upon the performance of their respective obligations under this Agreement. Notwithstanding the foregoing, if the period during which one Party's performance of its obligations hereunder is impaired due to an event of force majeure extends or can be reasonably expected to extend for greater than ninety (90) days, then the other Party may terminate this Agreement. Without limiting the generality of the foregoing, ATCO I-Tek shall be relieved of any failure or delay in performing the Services, and any failure in meeting any Service Level, to the extent that such failure or delay is caused by the direct and substantive failure or delay of Client in performing its responsibilities hereunder.

18.13 **Time of Day and Time**

Unless otherwise specified, references to time of day or date mean the local time or date in the City of Edmonton, Alberta. Time is of the essence in the performance by the Parties of their respective obligations hereunder.

18.14 **Remedies Cumulative**

Unless stated otherwise herein, all remedies provided for in this Agreement shall be cumulative and in addition to and not in lieu of any other remedies available to either Party at Law, in equity or otherwise. No single or partial exercise by a Party of any right or remedy precludes or otherwise affects the exercise of any other right or remedy to which that Party may be entitled.

18.15 **Understanding**

Each of the Parties acknowledges that it has read and understood this Agreement and agrees to be bound by its provisions.

18.16 **Facsimile; Counterparts**

This Agreement, and any document contemplated under this Agreement, may be executed in any number of counterparts which may be exchanged by facsimile, each of which shall be deemed an original and all of which together shall constitute one and the same Agreement.

18.17 **Affiliate Code of Conduct**

Each of the Parties hereto represents and warrants to the other that the Master Services Agreement, as amended hereby, complies with the ATCO Group Inter-Affiliate Code of Conduct (EUB Decision 2003-040).

IN WITNESS WHEREOF ATCO I-Tek and Client have executed this Agreement by their authorized officers in that regard, effective as of the date first above written.

ATCO I-TEK INC.
10035 – 105 Street
Edmonton, AB T5J 2V6
Attention: President
Facsimile: (780) 420-3157

Per: _____
Name: Bobbi Lambright
Title: President
Date executed:

Per: _____
Name: Pam Moellmann
Title: Vice President, Technologies
Date executed:

ATCO ELECTRIC LTD.
10035 – 105 Street
Edmonton, AB T5J 2V6
Attention: President
Facsimile: _____

Per: _____
Name: Signatory Name
Title: Title
Date executed:

Per: _____
Name: Signatory Name
Title: Title
Date executed:

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INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule A
Service Levels

SCHEDULE A – SERVICE LEVELS

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1.0 Introduction

This is Schedule A to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Client Survey**" has the meaning given in Section 1.5 (Client Satisfaction Survey).

"**Data Custodian**" has the meaning given in Appendix B (Security Framework Standards) hereto.

"**Data Guardian**" has the meaning given in Appendix B (Security Framework Standards) hereto.

"**Monthly Service Level Management Reports**" has the meaning given in Section 1.6 (Service Level Review and Change Procedure).

"**Outage**" has the meaning given in Appendix A (Application Support) hereto.

"**Security Framework**" has the meaning given in Section 3.0 (Appendices).

1.2 Scope

This Schedule outlines the specific service descriptions, Service Level measurements, specific applications and servers as of the Effective Date with respect to the delivery of the Service by ATCO I-Tek to Client.

1.2.1 Designated Managers

The Client Designated Manager and the ATCO I-Tek Designated Manager will be responsible for the management and administration of this Schedule and have full authority in connection with the management of this Schedule.

1.3 Service Management

ATCO I-Tek's focus is on Client satisfaction while providing efficient support and Service. ATCO I-Tek intends to meet or exceed the requirements established within this Schedule. The main aspects of service management are *availability*, *responsiveness*, and *serviceability* for all Service Categories.

1.3.1 Availability

Wide Area Network, Enterprise Server, Mid-range and Local Area Network Servers, Applications, Customer Support Center, and associated ATCO I-Tek support staff are generally available on a continuous 24 hours per day 7 days per week basis, with the exclusion of Change Windows.

This availability accommodates different scheduled uses of the environments for on-line processing, batch processing, backups, etc. Each application and/or server has an

established schedule that meets its requirements for each type of use as set out in Appendix A.

1.3.2 Responsiveness

Wide Area Network, Enterprise Server, Mid-range and Local Area Network Servers, Applications, Customer Support Center, and ATCO I-Tek support staff are engaged to meet and/or exceed service requirements as set out in and are identified in the Schedule C (Service Measures). Specific response times have not been documented for each application.

1.3.3 Serviceability

Serviceability is a measure of the support personnel's capability to resolve problems effectively. Due to the diversity of issues and resolutions, serviceability will be measured based upon the time to resolve the problem completely or provide an interim solution with a negotiated action plan that, upon completion, will have resolved the problem completely.

1.3.4 Management Procedures

ATCO I-Tek will periodically update management procedures within a reasonable time frame of changes being agreed to by Client to reflect alterations in the operations or procedures. Documentation will be published so that it is suitable for Client and ATCO I-Tek personnel to gain an understanding of the operational aspects of Tier I Services.

1.4 Technology Planning

On an annual basis, ATCO I-Tek will develop an information technology plan (IT Plan) that identifies and translates Client's business goals, Service Policies and existing infrastructure into a set of infrastructure requirements and a high-level, phased implementation strategy. This IT Plan will address Client's changing business needs and leverage emerging technologies. The purpose of the plan will be to:

- Establish a foundation for a secure, distributed client/server, Web, and mainframe environment that can be managed with a maximum of reliability and uniformity at a minimal cost.
- Provide input to an annual capital and operating budget.
- Promote information sharing, corporate efficiency, and user effectiveness.
- Expand the use of information technology, where applicable, while attempting to maintain operating costs and meet business needs.
- Identify trends, anticipate problems and develop innovative and cost-effective solutions.
- Seek a variety of views in the decision-making process.
- Recognize the value of proactive technology planning as an important IT community development resource.

ATCO I-Tek will work with Governance and the Chief Information Officer for the ATCO Group to jointly establish an IT Plan as defined in Section 7.2 (Annual Planning

Reviews) of the Agreement, that should include the characteristics of inter-operability, portability, flexibility, scalability, and usability.

The IT Plan and Strategy will promote the use of standard products and should address the following topics as applicable:

- ATCO business direction and operations (as provided by the Client).
- Enterprise-wide planning assumptions for the application of technology.
- Quantities of users, applications, Systems, and capital/operating costs as part of the annual planning process.
- Quantities to support automation plan for supported sites.
- Security.
- Desktop and server standards and configurations.
- LAN/WAN design.
- Approved products list.
- Technology refresh schedule.

Information Technology planning above the established baseline is available upon Client request on a Statement of Work basis.

1.5 Client Satisfaction Survey

ATCO I-Tek and the Clients have developed a "**Client Survey**" process to help identify the needs, opinions, and expectations of the Client. The Client Survey process will help evaluate and improve the Services provided by ATCO I-Tek to the Client by generating information that:

- Measures Client satisfaction in respect of Services provided
- Identifies key issues
- Evaluates the effectiveness of action plans

1.6 Service Level Review and Change Procedure

ATCO I-Tek and Client agree to annually review this Schedule as part of the Annual Review. This will be done with the objective of reviewing annual service levels, productivity expectations, business transaction volume projections, and responding to the impact of changes in information technology and management techniques, as well as changes in Client's expense reduction, service and application needs. It will contemplate the impact of the following items on the Services and/or Service Levels then being provided by ATCO I-Tek:

- Client's annual business planning process.
- Client's annual budget process.
- Mutually agreed additions, deletions or changes to the Services.

- ATCO I-Tek's performance over the previous year.
- Client Survey results from the previous year.

Services and/or Service Levels can be changed and implemented when there is agreement by Client and ATCO I-Tek. The process to change a Service or Service Level is as follows:

1) The authorized Client and ATCO I-Tek representatives will agree on and approve the change.
2) As the contract owners, the applicable ATCO I-Tek Designated Manager and the Client Designated Manager should be made aware of the change.

These changes will be documented in an amended version of this Schedule with an Effective Date of January 1st of the following year. The Client President (or his or her designate) and ATCO I-Tek President will sign the amended Schedule. Any adjustments to the price for the Services resulting from such amendments will be reflected in a revised Schedule D (Pricing).

In the event that a new Schedule is not in place as of January 1st of the following year, this Schedule will remain in effect.

ATCO I-Tek will provide "**Monthly Service Level Management Reports**" to Client to summarize ATCO I-Tek's Service Level performance as outlined in Schedule C (Service Measures). Monthly meetings will be held to discuss missed Service Levels. Depending on the severity of the problem, escalation may occur and additional meetings may be required. Schedule change requests can be submitted by Client or by ATCO I-Tek at any time and should be directed to the other Party's Designated Manager.

In addition to the Annual Review, three interim reviews of Services and Service Levels will be conducted on a quarterly basis. The interim reviews will (a) review ATCO I-Tek's performance to date (as reflected in the Service Level Management Reports), and (b) review any Schedule change requests submitted for consideration. As a by-product of these interim reviews, any changes, additions or deletions to the Services and/or Service Levels provided by ATCO I-Tek agreed to by the Parties in writing shall be documented for inclusion in the following year's revised Schedule and Schedule D (Pricing). Such changes, additions or deletions can be made effective at any time agreed to by the Client Designated Manager and the ATCO I-Tek Designated Manager, with an adjustment to invoicing as of such effective date.

2.0 Information Technology Services

The following is the list of all the Information Technology services that are available to the Client under the terms of the Agreement. The complete descriptions of the Information Technology services offered are detailed in Schedule B (Definition of Services).

1. Planning
2. Account Management
3. Standards
4. New Technology & Infrastructure

5. Customer Support Center
6. Security Management
7. Asset Management
8. Disaster Recovery
9. Computer and Facilities Management
10. Contract Management
11. Consulting
12. Training
13. Mainframe Management & Support
    - Production Management
    - Print Management
    - Hardware & Software
14. Workstation Management & Support
15. Server Management & Support
16. Network Equipment Management & Support
    - Manage LAN
    - Manage WAN
    - Manage Voice
    - Manage Video Conference
17. Application Management & Support
18. Database Management & Support
    - Development
    - Maintenance & Enhancement
19. Data Management

3.0 Appendices

The documents listed below are referred to within this document and are deemed to be part of this Schedule. Client and ATCO I-Tek recognize that the content of these documents is subject to change in response to operational changes. Changes to the documents will be adopted and agreed to by ATCO I-Tek pursuant to the Service Level Review and Change Procedure.

Appendix A - Application Support: includes the Application Support list.

Appendix B - Security Framework Standards: is a summary of the "**Security Framework**" which is a comprehensive set of standards to address all aspects of the security of information for the ATCO Group .

Appendix C - Disaster Recovery Methodology: describes the common critical path of activities included in the enterprise server disaster recovery plan.

Appendix D - Consolidated Technology Specifications: is the adopted consolidated set of Information Technology Standards for the ATCO Group.

Appendix E – Client Survey Process: is a process to determine Client satisfaction with the Services.

Appendix F – Priority Level Definitions & Notification Escalation: details the priority level criteria and the escalation procedure on problem tickets, and the interim process for service request tickets.

Appendix A: Application Support

Production Applications

Clients rely on their applications being operational during certain hours to:

- Access information;
- Update information; and
- Produce results and reports.

An application's availability and accessibility are dependent on one or more inter-connected components and the general support requirements for those components. In general, the network, the enterprise server and the LAN servers are available 24 hours a day, 7 days a week (24X7). However, time is required to perform System and data backups, System maintenance and application changes. General support includes Change Windows which are used to perform scheduled and emergency maintenance, and batch processing windows used to perform backups, database management (reorganizations and optimizations) and off-line (batch) processing. During these times on-line access to the application is impacted and could result in decreased performance or total inaccessibility.

The general application on-line availability is from Monday – Sunday 24X7 unless there are scheduled or unscheduled Outages provided that Service Levels are as identified on Schedule C (Service Measures). ATCO I-Tek provides supported availability during core Business Hours with the exception of applications with enhanced service levels. Applications are also dependent on the services and computers they use. The ATCO Network, enterprise server, LAN servers, IMS, ADABAS, DB2 and the availability of applications all have an impact on the applications and the Clients using them.

The unavailability of an application, during the supported times is designated as an "**Outage**". A planned Outage can be scheduled with the agreement of the Client, based on predetermined requirements and an implementation plan. Each application must be available for on-line processing during agreed to service hours. An unscheduled Outage is assigned a critical status and receives immediate attention to rectify the situation promptly, based on the problem management priority status. Many applications also have critical batch processing operations, which must be completed before the data can be accessed on-line. Ensuring the integrity of the application data takes precedent over maintaining on-line availability, unless the Client authorizes otherwise.

Enterprise Server

The enterprise server is currently used for several of the Client's production applications. The production applications use one of the three main database management systems:

- IMS (to be retired 2010)
- ADABAS (to be retired 2010)
- DB2

Based on ATCO's standards, DB2 is the primary mainframe database environment. ATCO I-Tek will decommission the ADABAS and IMS application environments at the end of June, 2010. Migration of existing ADABAS and IMS applications is required to be complete prior to year end 2009 to allow for time to decommission the environment. In the event that ADABAS and IMS application environments cannot be decommissioned by the end of June, 2010 due to Client decisions and not the actions of the ATCO I-Tek, the following charges will apply as incurred: (a) increased software license cost due to a planned upgrade of the mainframe and (b) maintenance costs. See also Sections 4.2.2, 4.2.4 and 4.2.7 of Schedule D (Pricing) of the Agreement.

The availability of a production application depends largely on the availability of the production environment (the database and the teleprocessing software) it uses. Test and development environments are maintained and follow separate availability schedules. If a Client wishes to use these environments or have access to these schedules, a request can be opened through the Customer Support Centre.

The on-line availability of a production application also depends on the batch processing requirements for the application.

- Daily batch processing is normally scheduled to begin at 18:00 each day, Monday to Friday. At this time, most applications become unavailable for on-line use, due to files being unavailable or locked.
- Certain applications have special requirements.
- Payroll batch jobs are initiated at 16:00 on Payroll days.
- Scheduled System tests, for application changes, may affect availability.
- Year-end processing for shared large scale applications is planned annually as part of the year-end processing project. Application availability may vary each year.

Database optimization, space increases and reorganizations are required from time to time, which restrict access to the applications data. Generally, these activities are scheduled; however, emergency processes may be required to rectify certain problems.

The Enterprise Server has some scheduled maintenance activities that affect general availability.

- Backup processing (full and incremental).
- Incremental backups are scheduled between 04:00 and 07:00 each day, Monday to Friday. Files being used during those times will be bypassed.
- Daily ADABAS backups are scheduled for Monday – Saturday at 03:00. The databases can still be active during these backups, but files being used will not be backed up.
- Weekly full ADABAS backups are scheduled for Saturday - Sunday 21:00-07:00. ADABAS is shut down (inactive) for this period. All files will be inactive and therefore backed up.

- Full backup and disk reorganization jobs are scheduled for Saturdays at 21:00 and are completed by 06:30 Sunday.
- Change Windows are outlined in the Change Management category in Schedule B (Definition of Services).

Core Business Hours for support are 08:00 – 17:00 Monday to Friday unless specifically identified.

PRODUCTION APPLICATIONS

Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
AC Master	PACE	1	Mon - Fri	08:00 - 17:00				
Accumap	Accumap	3	Mon - Fri	08:00 - 17:00				
Activity Tracking System	ATS	2	Mon - Fri	08:00 - 17:00				
Advantex (used in Work Management)		1	Mon - Sun	24x7			Sat & Sun	06:00 - 09:00
Alberta One Call		3	Mon - Fri	08:00 - 17:00				
Alberta Petroleum Marketing Commission	APMC	3	Mon - Fri	08:00 - 17:00				
ATCO Electric Geospatial I.S.	AEGIS	2	Mon - Fri	08:00 - 17:00				
ATCO Electric Outage Notification System	AEONS	2	Mon - Fri	08:00 - 17:00				
Audiology/Audiograf	AUDIO	1	Mon - Fri	08:00 - 17:00				
Auto Parts Management Benefits Administration System	WinSell - Auto Parts BAS	1 1 2 3	Mon - Fri Mon - Fri	08:00 - 17:00 08:00 - 17:00	Mon - Fri	18:00 - 07:00		
Bill2000 - Telus 800 Billing	BILL2000	1	Mon - Fri	08:00 - 17:00				
Bills 30	BILL30	2	Mon - Fri	08:00 - 17:00				
Building Management Manager	IA	1	Mon - Fri	08:00 - 17:00				
Business Objects	BO	2	Mon - Fri	08:00 - 17:00				
CADD	DE	1	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Capital Budget System	EV (CBS)	1 3	Mon - Fri	08:00 - 17:00				
Capital Programs Tracking		2	Mon - Fri	08:00 - 17:00				
CATS		1	Mon - Fri	08:00 - 17:00				
Commercial Inspections	EX (COMM_INSP)	1	Mon - Fri	08:00 - 17:00				
Competency Management Information System	CMIS	3	Mon - Fri	08:00 - 17:00				
Computer Aided Drafting	Intergraph	1 3	Mon - Fri	08:00 - 17:00				
Construction POS	GD (ConsPOS)	1	Mon - Fri	08:00 - 17:00				
Contact Registry System	EU (CRS)	1	Mon - Fri	08:00 - 17:00				
Control Rm Oper Window	CROW	2	Mon - Fri	08:00 - 17:00				
Corrective Action Request (CAR)	CAR	1	Mon - Fri	08:00 - 17:00				
Corrosion Tracking System	ES (Corr32)	1 3	Mon - Fri	08:00 - 17:00				
Cost of Service	ER	1	Mon - Fri	08:00 - 17:00				
CPXMM32 Maintenance manager	CPXMM32	1	Mon - Fri	08:00 - 17:00				
CU Water Billing System - Diamond	WIS	18	Mon - Fri	08:00 - 17:00				
Customer Choice (Dropchute & LPSS)		2	Mon - Fri	08:00 - 17:00				
Customer Management Module		1	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Daily Average Pool Price on Enet		2	Mon - Fri	08:00 - 17:00				
Daily Forecasting & Settlement System (Interfaces to IRIS).	DFSS	1	Mon – Fri	03:50 - 17:00				
Daily Oil Bulletin (Nickles)	Nickles	1	Mon - Fri	08:00 - 17:00				
Deferred Gas Analysis		1	Mon - Fri	08:00 - 17:00				
Details On Line	EL	1	Mon - Fri	08:00 - 17:00				
Directline Banking	Bank of Montreal	1	Mon - Fri	08:00 - 17:00				
Distribution Gas Information System	EM (DGIS)	1	Mon - Fri	08:00 - 17:00				
Distribution Planning Project	HT	1	Mon - Fri	08:00 - 17:00				
Drawing Control System		2	Mon - Fri	08:00 - 17:00				
ECHO Charitable Donation Database	EG (ECHO)	1 2	Mon - Fri	08:00 - 17:00				
Emergency Mapping	EGIS EMERG	1	Mon - Fri	08:00 - 17:00				
Employee Biographics System	EBS	1 2 3	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 - 06:59		
Employee Participating in Community	EPIC	3	Mon - Fri	08:00 - 17:00				
EnergySense Services Management System (CRM)	EA (EMS)	1	Mon - Fri	08:00 - 17:00				
ESSBASE	ESSBASE	2	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Estimating	Estimating	3	Mon - Fri	08:00 - 17:00				
Event Tracking System	Events	3	Mon - Fri	08:00 - 17:00				
Executive Graphics Info System	EGIS	1	Mon - Fri	08:00 - 17:00				
Executive Information System	EIS	1	Mon - Fri	08:00 - 17:00				
EZCHROM	DT	1	Mon - Fri	08:00 - 17:00				
Facility Maintenance Management System	FMMS - Maximo	2	Mon - Fri	08:00 - 17:00	Mon - Fri Sat Sun & Holidays	23:30 - 23:59 23:30 - 23:59 23:30 - 23:59		
Facility Operation System	FOS	3	Mon - Fri	08:00 - 17:00				
Fleet Focus (Maximus FA Suite)	FA Suite	1	Mon - Fri	08:00 - 17:00				
FMMS - Substation Inspection System	SINS	2	Mon - Fri	08:00 - 17:00				
FMMS - Tapchart	Tapchart	2	Mon - Fri	08:00 - 17:00				
FMMS - Testform	Testform	2	Mon - Fri	08:00 - 17:00				
Estimating	Estimating	3	Mon - Fri	08:00 - 17:00				
Event Tracking System	Events	3	Mon - Fri	08:00 - 17:00				
Fuel Cardlock System	PHOENIX	1	Mon - Fri	08:00 - 17:00	Mon-Sun	2:00-3:00		
Gannett Flemming	GANFLEM	1	Mon - Fri	08:00 - 17:00				
Gas Management System (GMS)	GMS	1	Mon - Sun	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Gas Chromatograph (EZChrome)	EZChrome	1	Mon - Fri	08:00 - 17:00	Mon-Fri	16:00 – 2:00		
Gas Engineering		1	Mon - Fri	08:00 - 17:00				
Gas Odorant Tracking Systems	Odor_Monitor	1	Mon - Fri	08:00 - 17:00				
Gas Valve Inspection (formerly Valve Inspection Tracking)	GAS VALVE (formerly Valves)	1	Mon - Fri	08:00 - 17:00				
GIS –AE	GT	2	Mon - Fri	08:00 - 17:00				
Glycol Analysis	IC (Glycol)	1	Mon - Fri	08:00 - 17:00				
Graphics Information (Ensight)	EGIS ENSIGHT	1	Mon - Fri	08:00 - 17:00				
Green House Gas	HK	3	Mon - Fri	08:00 - 17:00				
Hitline Database	Hitline	1	Mon - Fri	08:00 - 17:00				
Mon – Fri Human Resource Excellence	HRX	1 2 3		08:00 – 17:00 and during scheduled Payroll runs				
Hyperion	JF	2	Mon - Fri	08:00 - 17:00				
Imbalance Reporting Info System	IRIS	1	Mon - Fri	08:00 - 17:00				
Industry Dialogue Manager (IDM)	HY	1	Mon - Fri	08:00 - 17:00				
Instrument Calibrating System	DH (ICS1)	1	Mon - Fri	08:00 - 17:00				
Instrument Recording System	DC (IRS GAS)	1	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Imbalance Reporting Information System (IRIS) Interfaces to DFSS	27	1	Mon - Sun	24x7				
Intelex Quality Management System	JE	1	Mon - Fri	08:00 - 17:00				
Isolated Generation Reporting	IGR	2	Mon - Fri	08:00 - 17:00				
Isolated Plants System	ISOSYS	2	Mon - Fri	08:00 - 17:00				
Job Costing System JV Uploads	JCS JVUPLOAD	1 2 3 1 3	Mon - Fri Mon - Fri	08:00 - 17:00 08:00 - 17:00	Mon - Fri	18:00 – 06:59		
Khalix		1	Mon - Fri	08:00 - 17:00				
Kedit	KEDIT	1	Mon - Fri	08:00 - 17:00				
Land and Properties Management System	LPMS	2	Mon - Fri	08:00 - 17:00				
Land Information System	CY (LIS)	1 2	Mon - Fri	08:00 - 17:00				
LANDMAN	(41) LANDMAN	1	Mon - Fri	08:00 - 17:00				
Leak Analysis Management System (LAMS)	HZ	1	Mon - Fri	08:00 - 17:00				
Least Cost SCADA		2	Mon - Fri	08:00 - 17:00				
Load Duration Curve Models	Load Duration Curve Models	1	Mon - Fri	08:00 - 17:00				
Load Research Data Maintenance & Analysis	DMA	2	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 – 06:59		

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
LodeSTAR-Load Research	LodeSTAR	2	Mon - Fri	08:00 - 17:00				
Managerial Reporting	CK (MR)	1 2	Mon - Fri	08:00 - 17:00				
Mastertech/Techview (Techview for Windows)	TECHVIEW	1	Mon - Fri	08:00 - 17:00				
Maximo Cost Tracking System		2	Mon - Fri	08:00 - 17:00				
Maximo (Work Management)		1	Mon - Sun	24x7				
Measurement and Reporting System	MARS	3	Mon – Sun	05:00 – 23:00			Mon - Sun	06:00-22:00
Meter Prover	CL (DRESSER)	1	Mon - Fri	08:00 - 17:00				
Meter Proving System	MPS	1	Mon - Fri	08:00 - 17:00				
MeterMaster	METERMASTER	1	Mon - Fri	08:00 - 17:00				
Metretek DC2000	METRETEK	3	Mon - Fri	08:00 - 17:00				
Metscan	(CQ) Metscan	1	Mon – Fri	08:00 - 17:00	Mon-Fri	22:00, 1:00am, 3:00am,3:30am, 3:35am, 7:10am	Mon-Fri	22:00-10:00am
Metscan Device Setup	CID	1	Mon - Fri	08:00 - 17:00				
Micrographics (VersaImage)	VersaImage	1	Mon - Fri	08:00 - 17:00				
MicroPoint POS (Cashier System)	MicroPoint	1 2	Mon - Fri	08:00 - 17:00				
Microstation	CP (USTATION)	1 2	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Mileage Tracking System	Mileage Tracking System	1	Mon - Fri	08:00 - 17:00				
Monarch	Monarch	1	Mon - Fri	08:00 - 17:00				
MP2000	IVR	1	Mon - Fri	08:00 - 17:00				
MV-90XI	IT	1	Mon - Fri	08:00 - 17:00				
Natural Gas Exchange	NGX	3	Mon - Fri	08:00 - 17:00				
Natural Gas Vehicles Fleet Billing	NGV	1	Mon - Fri	08:00 - 17:00				
NGV Fleet	IB	1	Mon - Fri	08:00 - 17:00				
Non-Gas Sales Information System	NGSIS	1	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 – 06:59		
NrG Information Highway	NrG	3	Mon - Fri	08:00 - 17:00				
Oracle Financials	OFIN	1 2 3	Mon - Fri	08:00 – 17:00				
Payroll Distribution System	PDS	1 2 3	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 - 07:00		
Payroll Human Resources System	PHRS	1 2 3	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 - 07:00		

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Payroll T4 System	HPS	1 2 3	Mon - Fri	08:00 - 17:00				
PC Automate	PCAUTO	1	Mon - Fri	08:00 - 17:00				
Peaksimple Chromatography	CHROM	1	Mon - Fri	08:00 - 17:00				
Pegasys Server Application	Pegasys	2	Mon - Fri	08:00 - 17:00				
Petroleum Safety Training	MAKESAFE	1	Mon - Fri	08:00 - 17:00				
Phoenix	HE	1	Mon - Fri	08:00 - 17:00				
Pipeline Evaluation Program	PEP	3	Mon - Fri	08:00 - 17:00				
Pipeline Reg Station Inspection	PIPELINE REGS	3	Mon - Fri	08:00 - 17:00				
Pipeline Valve Inspection	PIPELINE VALVE	3	Mon - Fri	08:00 - 17:00				
Premier Plus 4	BW (PP4 or P+4)	1	Mon - Fri	08:00 - 17:00				
Pressure Factor Measurement System	BV (PFMS)	1	Mon - Fri	08:00 - 17:00				
Pro Fuel Plus	AD	1	Mon - Fri	08:00 - 17:00				
Projectwise	BT	1	Mon - Fri	08:00 - 17:00				
Property Tax System	PTS	1 2	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 – 06:59		
Quality Assurance Audit	BQ	1	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Ororant Tracking	CG	1	Mon - Fri	08:00 - 17:00				
Rate Expert	BM	2	Mon - Fri	08:00 - 17:00				
Regstations (Reg Station Inspection)	BL (RegStn)	1	Mon - Fri	08:00 - 17:00				
Remote Access to Maximo		2	Mon - Fri	08:00 - 17:00				
RightFax NT	RIGHTFAX	1 2 3	Mon - Fri	08:00 - 17:00				
Safe Work Management System	AV (SWMS)	1 2	Mon - Fri	08:00 - 17:00				
Service Interruption Reporting	SIR	2	Mon - Fri	08:00 - 17:00				
Sharepoint	GR	1	Mon - Fri	08:00 - 17:00				
Staff Purchases Tracking System	Staff Purchases Tracking System	2	Mon - Fri	08:00 - 17:00				
Standards and Quality Assurance Database	AX (SQAM)	1 3	Mon - Fri	08:00 – 17:00				
Surface Lease Management System	AW (SLMS)	1 3	Mon - Fri	08:00 - 17:00				
SynerGEE	SYNERGEE	1 3	Mon - Fri	08:00 - 17:00				
SynerGEE CMM	SynerGEE CMM	1	Mon - Fri	08:00 - 17:00				
SynerGEE USM	SynerGEE USM	3	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
System for Transportation and Accounts Reporting	STAR	3	Mon - Sun	05:00 – 23:00	Mon - Sun	1st: 16:00 5th: 18:00 10th: 8:00 18th: 8:00 Cycle1: 07:10 – 12:00 Cycle2: 11:40 – 16:00 Cycle3: 15:40 – 20:00 Cycle4: 20:00 – 00:00 Cycle5: 06:15 – 11:30 Cycle6: 10:00 – 12:00	Mon - Sun	06:00 - 12:00
Tables on Diskette	AS	3	Mon - Fri	08:00 - 17:00				
Time Entry System	TES	1 2 3	Mon - Fri	08:00 - 17:00	Mon - Fri	18:00 – 06:59		
ToolHound	AN	1	Mon - Fri	08:00 - 17:00				
TRACCESS	IV	2	Mon – Fri	08:00 – 17:00				
Tracking Contact	HX	2	Mon - Fri	08:00 - 17:00				
Trading Partner PC	EDI	1 3	Mon - Fri	08:00 - 17:00				
Transmission Outage Tracking		2	Mon - Fri	08:00 - 17:00				
TRIM Records Management	AJ	1 2	Mon - Fri	08:00 - 17:00				
Two Way Automatic Communication System (TWACS)	TWACS	2	Mon - Fri	08:00 - 17:00				

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Application	ID	Co No	Supported Days	Supported Times	Batch Processing Days	Batch Processing Times (Mountain Daylight Time)	Client Critical Days	Client Critical Times
Valve Inspection	AG	1	Mon - Fri	08:00 - 17:00				
Vision for Maximo		2	Mon - Fri	08:00 - 17:00				
Vista	PEGASYS	2	Mon - Fri	08:00 - 17:00				
Way to View	FRAMME	1	Mon - Fri	08:00 - 17:00				
Weld Calculation	WELDIT	3	Mon - Fri	08:00 - 17:00				
Winbeep 32	WINBEEP32	1	Mon - Fri	08:00 - 17:00				
Winsell	AC	1	Mon - Fri	08:00 - 17:00				
X windows	XWIN	3	Mon - Fri	08:00 - 17:00				

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ENTERPRISE SERVER

Legend:

Database Management (DBM) ***Technical Support (TS)*** ***Production Systems Support (PSS)*** ***Systems Development (SD)***

Component	ID	Level 2 Support	Level 3 Support	Post Avail	On-line Processing Days	On-line Processing Time	Batch Processing Days	Batch Processing Time	Notes
ADABAS	ADA200	DBM	TS	Yes	Mon-Fri Sat Sun & Hol	00:00 - 23:59 00:00 - 21:00 07:00 - 21:00	Mon - Fri	18:00 - 07:00	End of Life - 2010
AFP		TS	TS	No					
CICS	CICS	TS	TS	Yes	Mon-Fri Sat Sun & Hol	00:00 - 23:59 00:00 - 21:00 07:30 - 21:00			
DB2		DBM	TS	Yes	Mon-Fri Sat Sun & Hol	00:00 - 23:59 00:00 - 21:00 07:30 - 21:00	Mon - Fri	18:00 - 07:00	
Express Delivery		PSS	PSS	Yes	Mon - Sun	00:00 - 23:59			
IMS Data Dictionary	DSIM UCC10	DBM	DBM	No	Mon - Fri	07:30 - 18:00	Mon - Fri	18:00 - 07:00	
IMS	IMS	DBM	TS	Yes	Mon-Fri Sat Sun & Hol	07:30 - 23:59 07:30 - 21:00 07:30 - 21:00	Mon - Fri	18:00 - 07:00	End of Life - 2010
JOBTRAC	JOBTRAC	PSS	PSS	Yes	Mon-Fri Sat Sun & Hol	00:00 - 23:59 00:00 - 21:00 07:30 - 23:59			Batch Job Scheduling on the Mainframe
Z/OS		TS	TS	Yes	Mon-Sun	00:00 - 23:59	Mon - Fri	18:00 - 07:00	
Natural		SD	TS	Yes	Mon-Sun	00:00 - 23:59	Mon - Fri	18:00 - 07:00	
SAR SARRPT		PSS	PSS	Yes	Mon-Sun	00:00 - 23:59	Mon - Fri	18:00 - 07:00	

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Component	ID	Level 2 Support	Level 3 Support	Post Avail	On-line Processing Days	On-line Processing Time	Batch Processing Days	Batch Processing Time	Notes
SARPSM									
SNSTCP		TS	TS	Yes					
TLMS		PSS	TS	Yes	Mon-Fri	00:00 - 23:59			
TSO	TSO	TS	TS	Yes	Mon-Fri Sat Sun & Hol	00:00 - 23:59 00:00 - 21:00 00:00 - 23:59			
VPS		TS	TS						

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Appendix B: Security Framework Standards

Security Management – Access and Data Protection

Data security is the control established to protect against accidental or intentional modification, destruction or disclosure of Client and ATCO I-Tek proprietary and/or confidential data. Security is provided for all computers (enterprise server, mid-range, and LAN servers). The Client is responsible to authorize and track who can retrieve and update data. It is the responsibility of the Client to address situations where unauthorized access attempts have been reported.

ATCO I-Tek will provide Services to maintain and manage data and computer access security in accordance with ATCO Group standards.

Access to computer processors is restricted to people with a valid User Id and password. Access to databases and files is further restricted through security software features that allow full or read-only access and/or refuse access totally.

Remote access security is in place on the ATCO I-Tek supported network for VPN (Virtual Private Network) access service. VPN connectivity is protected by the creation of a secure, encrypted tunnel across the internet to the ATCO corporate network for each session.

ATCO I-Tek provides services to maintain and manage information and computer security in accordance with the ATCO Group Information Technology standards.

Security Planning

Security planning is the formulation of security standards for the computing infrastructure. The set of security standards address the mandate of the ATCO Group Information Technology practices, new emerging threats to the infrastructure, Information Security compliance requirements as well as approved Audit recommendations.

Security prevents unauthorized access to the network and data from outside the ATCO Network. ATCO I-Tek provides computer and data access administration that provides confidentiality and integrity as well as Data Guardian records.

Security Administration

ATCO I-Tek will continue to support the security practices and processes developed by ATCO including the data owner philosophy. User logon security is generally provided through the server operating systems and, in some cases, by individual applications.

ATCO I-Tek responsibilities for security administration are:

- Immediately notify Client of known security violations.
- Resolve security violations as they pertain to ATCO I-Tek facilities, Systems, networks, personnel or other assets.
- Provide training in security administration to application coordinators, as appropriate.

- Provide System security utilizing password aging features, protected log-ins, directory and file protection at the user level/group level, protection with read/write/execute privileges, and security encryption features.
- Investigate, report, and resolve security issues, with Client's assistance as required.
- Process emergency / non-routine requests for User Id adds, changes and deletes within mutually agreed upon (Client and ATCO I-Tek) timelines.

Security Monitoring

Security monitoring is the security process that protects ATCO I-Tek and Client assets from threats through the following actions:

- Scanning the network resources for viruses.
- Establishing secure information access and usage.
- Authorizing and authenticating access to resources.
- Conducting security monitoring.
- Backing up and restoring data and application files.

ATCO I-Tek responsibilities for security monitoring are:

- Access only with appropriate authorization from Client.
- Managed supervisory access to administer servers.
- Provide authorized users with password resets.
- Maintain compliance with the established security standards.
- Security patch compliance monitoring.

Access

Authentication - All System users, either individuals or connected processors, must be uniquely identified and authenticated. Authentication is typically provided when a password is used with user identification (User Id) and provides a method for uniquely identifying and verifying who is attempting to use a System resource.

Authorization - Access to System resources is limited to authorized individuals. The resources of the Client are protected from access except to individuals or connected processors that have been specifically granted access on a need to know basis.

Passwords – In order to establish a level of trust during the authentication Passwords must be kept secret and should be complex enough to prevent guessing, but not so complex to not be remembered.

Management

Compliance Monitoring - Mechanisms and procedures to monitor compliance with Service Policies including security measures will be maintained. The monitoring of compliance to the Service Policies will establish accountability for the actions of users.

Data Guardianship (Ownership) - The "ownership" of all corporate data must be assigned to an individual known as a "**Data Guardian**". The Data Guardian is typically the Manager of the department that generates the data or information. The Data Guardian is responsible for making and communicating decisions, on behalf of the organization, so that the data is controlled and accessed only by those with the authority to do so.

Data Custodianship (Management) - The management of all corporate data must be assigned to an individual known as a "**Data Custodian**". The Data Custodian is responsible for defining the procedures required for data access and invoking the authorization process based on approval from the Data Guardian.

Deviations to Policies and Standards - All deviations from and non-compliance with Service Policies will be recorded and processed in accordance with their nature and circumstances. Non-compliance or deviations to the Service Policies and procedures can cause security exposures and potential impact to the business.

Management Responsibilities - Management is directly responsible for monitoring and enforcing adherence to the ATCO Group Information Technology Service Policies and standards by the individuals and System components within their direct control.

Operational Support - An operational support function should be in place and be responsible for providing a stable operating environment of computer Systems. Lack of attention or avoidance of operational support activities may provide an unstable environment that may be open to compromise.

Risk Assessment - Identification and evaluation of the type of risks, their probability of occurrence, and their potential adverse impact on an information System will be used as a base for determining security requirements.

Security Administration - A security administration function has the responsibility to carry out the administration of security components, processes, and procedures.

Segregation of Duties - To reduce the opportunities for any person to breach security, no individual, regardless of seniority, should have the ability to carry out every step of a sensitive business transaction. Consider controls that separate a process into component parts and require different authorized users to perform different parts in order to complete the process.

Systems Development - Security considerations must be considered whenever a new computer System is being designed and developed. Security features should include but not be limited to standard access policies, controls through data classification, data and System integrity, and user accountability through audit information, and should provide for continuity of service.

Standards - The use of standards is an important principle that will apply to all Systems and business processes where adoption of standards has been approved and documented. Deviations from the documented standards will require business justification.

Software

Software Copyright - All users of software will strictly adhere to the terms and conditions regarding copyright, as outlined in licensing agreements accompanying each software product.

Virus Protection - A virus protection and detection process is required to be maintained in the operation of the computer Systems. All external data and software introduced into the System must be first checked for the presence of any viruses.

Data

Classification of Data - All data must be classified by its nature and purpose in order to apply the appropriate measures regarding integrity, availability and confidentiality of the information.

Integrity of Data - Data that is used to carry out the Client's business must be accurate and available for use when required. The data must be protected and measures invoked to provide accuracy and availability of the data. The measures used will be in accordance with the classification of data.

Information

Audit Information - Where identified as a requirement for a specific application, a record of System activities will be maintained that is sufficient to enable the reconstruction, review and examination of a completed transaction, from its inception to output of final result. These records must be maintained in accordance with legal, government, industry, or corporate regulations.

Privacy of Information - Personal and Client Data will be protected from accidental or deliberate disclosure in compliance with the Protection of Privacy Act of the Province of Alberta.

Classification of Information - The information that is maintained within the Client organization should be reviewed and classified according to its importance, availability and sensitivity requirements.

Integrity of Information - Mechanisms, processes, and procedures must be maintained to provide integrity of Systems information. This is a required standard for business computing Systems and will promote the secure operation of Systems.

Systems

Classification of Systems – All data, information, and Systems generated or maintained are subject to a classification depending on their nature and use. Classification enables ATCO I-Tek to make recommendations and decisions on the level of protection required, as well as providing input into the backup and recovery plans.

Business Continuity - All business Systems will be subject to an appropriate level of business continuity planning to meet availability requirements and to limit the impact of service interruption. Business Continuity is the responsibility of each Client. The unavailability of data, components or Systems could have a serious impact on business operation.

Users

Personal Use - Employees shall not utilize the System resources to support any activities other than those that support their duties of employment. All product(s) developed on System resources are owned by Client and permission must be granted for personal use. An employee does not have the right to sell, distribute or copy any material developed in support of their job functions without an appropriate level of authorization.

Use of Information Systems - Users must not use information Systems in an illegal, immoral, unethical, or harmful manner. The expanding use of technology for electronic mail and information exchange both internally and externally provides an expedient method for creating and distributing information. The users of these information Systems must utilize the Systems in a legal, responsible manner.

User Awareness - Communication programs will be implemented and maintained to make users aware of the requirement for security and the facilities, processes and procedures that support the security requirements.

User Responsibilities - Users of the Systems must be knowledgeable of and adhere to the security framework as specified. Users are responsible and accountable for all System(s) access made using their identification code.

Network

Electronic Mail - The use of electronic mail Systems must be limited to company and company related interests. Privacy and confidentiality of communications must be respected and the Systems used in a secure manner.

Facsimile and Telephone Integrity - The privacy of telephone and facsimile communication must be respected and these forms of communication must be used in a secure manner. Both facsimile and telephone facilities are to be used for business use only. Non-business use is discouraged. The privacy of telephone conversations and facsimile transmissions should be respected, and the use of these facilities for exchanging highly Confidential Information should be restricted.

Toll Fraud - Telecommunications Systems must be protected to deter unauthorized and fraudulent use of facilities. Access to functions / features must be controlled by safeguards implemented into the System including, but not limited to the adequate control of calling privileges, protected physical access and authorized remote access methods.

Remote Network Access (Employee) - The appropriate justification and security measures must be utilized to provide employees remote access to Systems from a remote location. Implementing access to local Systems or the ATCO Network without adhering to the approved security measures is considered a serious exposure and is strictly prohibited.

Remote Network Access (Non-employee) – Remote access to the ATCO Network may be granted to non-employees with the appropriate business justification. Stringent network access measures will be enforced to control access requirements for individuals who are not in the employ of ATCO. Abuse of any non-employee access will result in immediate termination of the privilege.

Internet - The Internet is to be used for business related activities only and by authorized personnel with a valid Internet account. Corporate user identification code(s) and password(s) are not to be disclosed over the Internet, and all sensitive or Confidential Information that is transmitted must be encrypted. The downloading of games, viruses, inappropriate graphics or picture files, and illegal software from the Internet is prohibited.

Other

Physical Security - Measures are required for protecting computers, related equipment (including utilities), and the processing facility itself. Physical security mechanisms such as the use of locks, security guards, access cards, badges and alarms are to be utilized to prevent unauthorized personnel from gaining access to the facility or equipment.

External Processing - External service organizations supplying processing Services to the Client, or off-premises processing done by employees requires a secure environment and controls. The use of external processing service bureaus or external processing of

information is subject to a review of security controls and adherence to appropriate management mechanisms.

Appendix C: Disaster Recovery Methodology

During a recovery effort, ATCO I-Tek follows a common critical path of activities as graphically illustrated below. There are major nodes along the critical path which are followed regardless of computing resource and business organization.

Where: **B** Is the last backup taken prior to the event.

E Is the event, or contingency. Any disruption must be evaluated to determine the severity and estimated time to recover.

D Decision whether or not to declare a disaster. The ATCO I-Tek Emergency Management Team will make the final determination to activate the DRP plan. Included are the 'Initial Response/Reaction' steps required for protection of life, property, damage assessment and staff mobilization. This is considered Stage 1 of the recovery plan.

U Stage 2 – Is the point at which the mainframe environment is restored. This will include the operating system and associated program products. For the distributed environment, it includes restoring infrastructure servers and services as well as servers used for the restoration of business applications. It is also the time when recovery of the ATCO data network and voice communications takes place.

A Stage 3 – Is the restoration and verification of the mainframe and distributed business databases and applications. This operation is highly dependant on the backup and restoration procedures in place.

DS Stage 4 - Is the point where applications are synchronized, and lost and stockpiled data is entered by Clients.

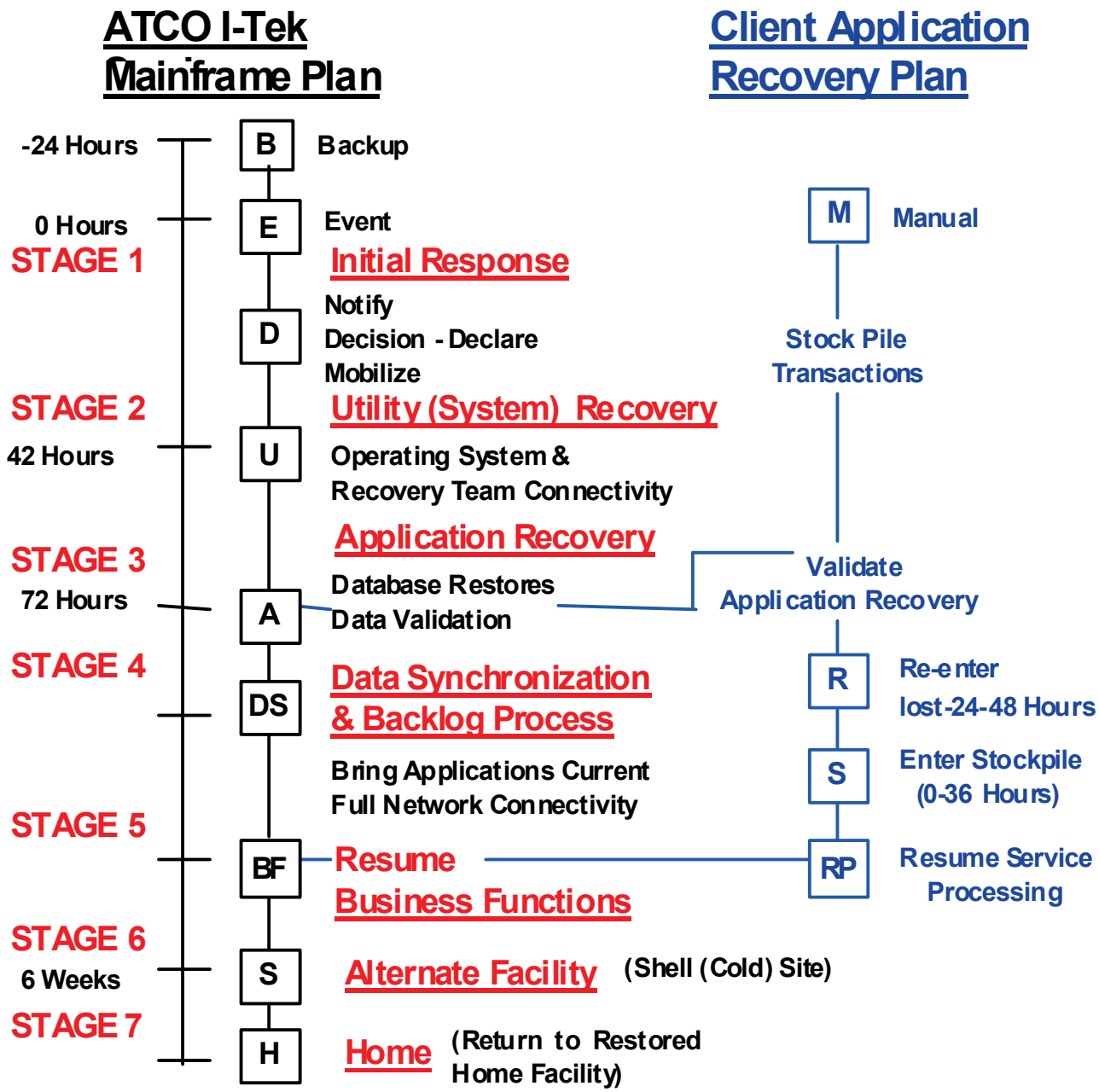
BF Stage 5 - Is the point at which the normal resumption of processing can occur and business functions are considered fully recovered.

S Stage 6 - Is the optional migration of the mainframe to a shell (cold) site facility should the hot site be required by another customer. Migration to a shell site is not required for the distributed environment since the servers are recovered at the alternate data center. The servers will be operated from there until return to the home site.

H Stage 7 - is the pre-planned return to the recovered host facility (home).

The following diagram illustrates the timelines associated with the seven stages of recovery, as they apply to the ATCO I-Tek enterprise server disaster recovery plan.

DISASTER RECOVERY PLAN OVERVIEW



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Appendix D: Consolidated Technology Specifications

Client / Desktop

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Operating System	Windows XP	Win 32 API's	Windows 7	

Distributed Infrastructure Server

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Corporate Network Operating System (CNOS)	Windows 2000 Server, Windows 2003 Server	Win 32 API	Windows 2003 Server, Windows 2008 Server	
	UNIX-NFS			

Application / Database Server

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Application Server OS	Windows 2000 Server, Windows 2003 Server, Solaris	Win 32 API, UNIX	Windows 2003 Server, Windows 2008 Server, Solaris	
Database Server OS	Sun Solaris 10	UNIX System 5 Compliant	Sun Solaris 11	

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Data Access

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Mainframe DBMS	DB2, Adabas, IMS	Ansi SQL Compliant	DB2	
Shared DBMS , non Mainframe	Oracle, MS Access	Ansi SQL Compliant	Oracle	
Desktop DBMS	MS Access	Win 32 API	MS Access	
Data API	ODBC, direct data access to all DBMS's	ODBC or direct to DB2, Oracle, MS Access		

Communications

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Protocol	TCP/IP, 802.3	TCP/IP, 802.3	TCP/IP, 802.3	
Horizontal Wiring	Cat 5E UTP, T568A	Category 5E UTP, T568A	Commodity	
Vertical Wiring	Cat 5E T568A, Fibre,	Cat 5E T568A, fibre,	Commodity	
Horizontal Topology	802.3	802.3	Commodity	
Vertical Topology	802.3,	802.3	Commodity	
WAN Connectivity	Frame Relay, Ethernet ADSL Bridged, Ethernet Bridged Fibre, Dedicated, VPN	High speed converged, Ethernet ADSL, Ethernet Bridged Fibre, Dedicated, VPN for small office sites where applicable	Carrier commodity	

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Messaging / E-mail

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Email Engine/Client	Microsoft Exchange/ Microsoft Outlook	Client/server mail architecture	Microsoft Exchange/ Microsoft Outlook	
		MAPI mail enablement		External E-mail.

Hardware Platform

Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Workstation	Desktop Intel Core Duo 1.86 Ghz or greater Laptop Intel Core Duo 1.83 Ghz or greater	Processor: Intel Multi Core PCI or PCIe bus Disk SubSystem: SATA, Video: SVGA, 16MB Monitor: 19 Inch, True color, 1280x1024 Resolution RAM: 2 GB on board	Business Class workstations at current specification	
Departmental Printers	Low Volume 266 Mhz, 25 ppm, Duplex, 8 ½ x 11 Medium Volume	Postscript Level 3, HPGL 5E, Duplex Handler,	Multifunction Devices at current specifications Business Class Printer at current specifications	Migration through standardization of photo copier/print/fax functions

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Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
	300 Mhz, 35 ppm, Duplex, 8 ½ x 11 / 8 ½ x 14 High Volume 250 Mhz, 32 ppm, Duplex, 11 x 17			
Personal Printers	Business Class Printer at current specifications	Postscript Level 3, HPGL 5E, Duplex Available	Business Class Printer at current specifications	Migration through attrition or positive business case.
Colour Printers	Low Volume 264 Mhz, 8 ppm, 8 ½ x 11 35,000 duty cycle Medium Volume 533 Mhz,	Postscript Level 3, HPGL 5E, Laser	Business Class Printer at current specifications	Migration through attrition or positive business case.

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Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
	22 ppm, 8 ½ x 11 / 8 ½ x 14 Duplex 65,000 duty cycle High Volume 533 Mhz, 22 ppm, 8 ½ x 11 / 8 ½ x 14 Duplex 85,000 duty cycle Ultra High Volume 533 Mhz, 27 ppm, 11 x 17 Duplex 120,000 duty cycle			

Personal Productivity

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Element	Current	3 Year Target Specification	3 Year Target Product/Buy List	Comments
Word Processing	MS Word	Win 32 API MS Office Suite	Word	
Presentation	PowerPoint, IGRAFX Flow Charter, Corel Draw, Adobe product set	Win 32 API MS Office Suite, Adobe Presentation Suite	PowerPoint, Adobe Product set	
Spreadsheet	Excel	Win 32 API MS Office Suite	Excel	

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Appendix E: Client Survey Process

ATCO I-Tek and Clients have agreed that, for all closed Problem Tickets and Requests, ATCO I-Tek will survey the end users to confirm that their problems or requests have been dealt with satisfactorily. ATCO I-Tek and Clients have agreed that the ATCO I-Tek account manager will be obligated to meet at least monthly with Client Representative to discuss Client satisfaction with regard to Services.

Appendix F: Priority Level Definitions & Notification Escalation:

Problem Tickets

Priority Levels	Escalation Time (During Normal Business Hours)	Management Contact	Priority Definition
Critical	Immediate Immediate Immediate Exceed TTS	CSC Supervisor Direct Support ATCO I-Tek Manager ATCO I-Tek Designated Manager ATCO I-Tek Service Area Manager IT Governance Representative, as required CIO Office, as required	A problem causing an unscheduled interruption to availability of an application, a production server or interrupted customer services. Business impact is or will be severe.
High	Immediate Exceed TTS	Direct Support CSC Supervisor ATCO I-Tek Manager IT Governance Representative, as required	Problem has disrupted customer service. Customer can continue to process, but at great inconvenience. Business impact is high.
Medium	Exceed TTS/TTR	CSC Supervisor ATCO I-Tek Manager	Customer service is degraded. Business impact is moderate to low. Solution required in the short term.
Low	Exceed TTS/TTR	CSC Supervisor ATCO I-Tek Manager	Current customer service has low or negligible impact. Business impact is low. Solution required in the long term.

Appendix F: Priority Level Definitions & Notification Escalation: (cont'd)
Service Request Process

Service Request Escalation Process - ATCO I-Tek's service request process is based on industry standards as defined in the IT Infrastructure Library (ITIL). To manage the service request process, ATCO I-Tek utilizes an automated service desk solution that provides problem, request and change management across the enterprise. The process includes service request logging, efficient routing to the appropriate work areas, and escalation. This promotes quality control by increasing resource efficiency, managing the cost of service delivery and improving Client satisfaction.

A full lifecycle process is implemented to monitor and confirm that all service requests are correctly completed and escalated when necessary. The central point of contact for service requests is the Customer Support Centre (CSC). Upon receipt of a request, the CSC will determine whether the request can be solved at the time of the request or will coordinate the escalation of the request to Tier II level support. All requests are tracked and monitored. In the event that a request is not closed within the original estimated time to completion (dependent on the complexity of work), an automated escalation is sent to the appropriate Tier II support for follow up. Regular exception reporting is completed and provided to the ATCO I-Tek Team Leads and Management for resolution.

The Client will provide updates to forecasts and other workload planning information to ATCO I-Tek at each monthly meeting with the ATCO I-Tek Account Manager, at the time of the Annual Review and from time to time as reasonably requested by ATCO I-Tek and at other times as reasonably provided by the Client, to enable ATCO I-Tek to plan the Services, Service Requests and Statements of Work.

ATCO I-Tek is relying on the forecasts and the workload planning information as they are essential to ATCO I-Tek to identify workload planning and capacity issues that will impact Service Levels.

If the number of service requests or Statements of Work initiated or agreed to by the Client that ATCO I-Tek is required to prepare in any month exceeds ATCO I-Tek's capacity to properly handle the work, ATCO I-Tek will give notice to the Client and the Parties will meet promptly:

(i) to identify the service request(s) or Statement(s) of Work that may be deferred or withdrawn and to assign priorities to the remaining Service Request(s) or Statement(s) of Work;

(ii) to discuss what additional costs ATCO I-Tek is required to incur to permit it to prepare the service request(s) or Statement(s) of Work and to determine whether the Client should compensate ATCO I-Tek for any additional costs; and

(iii) to assess whether any other mutually agreeable solution is available.

In the event that a client is dissatisfied with the work performed, they have the option to respond with their concerns through the automatic online client feedback process. This feedback process is in place for all closed requests. ATCO I-Tek reviews all client feedback to determine if further action is necessary. Outstanding client requests are managed through internal escalation processes.

In the event an escalation to the CSC does not resolve the issue, the clients have the option to escalate a complaint directly to the ATCO I-Tek Designated Manager. It is this Manager's responsibility to then own the issue until the proper area has addressed the issue with the Client. The IT Account Manager will perform the necessary escalation within ATCO I-Tek, working with the appropriate manager/management groups to obtain resolution. In the further event that the issue is not resolved, Client has the option to escalate the issue to the Chief Information Officer at the ATCO Group.

Should the Parties not be able to resolve the issues, the Dispute Resolution process can be invoked as per Article 16 (Dispute Resolution) Agreement for the ATCO Group.

INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule B
Definition of Services

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SCHEDULE B – DEFINITION OF SERVICES

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1.0 Introduction

This is Schedule B to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**On-site**" has the meaning given in Section 2.5 (Customer Support Centre).

"**PBX**" has the meaning given in Section 2.16 (Network Equipment Management & Support).

1.2 Tier 1 Services

Tier 1 Services are the Client operational Services "Mouse pad to Server". These Services include Information Technology Services, which are provided to each Client that is participating in the Agreement. These Services will be delivered and will meet or exceed the Service Levels outlined in the service measurement document. These include all major Services defined in this section and are generally described as:

- Applications maintenance and enhancements (<40 person days)
- Application Service Provider Service (ASP)
- Distributed Server and Application Managed Service
- Mainframe Service
- Project Labour Service
- Storage Service
- User Connectivity Service
- Network Connectivity Service
- Voice Service
- Workstation Service

1.3 Tier 2 Services

Tier 2 Services involve the introduction of Change or new technologies to the Client and apply to development projects requiring more than 40 person-days of work. These projects will require more formal project management. Tier 2 project cost estimates will include all costs associated with the development, implementation and on-going,

incremental, operation and maintenance resulting from the project. ATCO I-Tek will have first right of proposal for all Tier 2 Services.

All new Tier 2 Services required by Client shall commence with a Request, as provided for in Article 4 (Statements of Work and Approval of Deliverables) of the Agreement. However, if within a reasonable time following the making of a Request, Client and ATCO I-Tek have not agreed on a Statement of Work (i.e., Client has not received a proposal from ATCO I-Tek that is acceptable to Client) the Client may select a vendor other than ATCO I-Tek. In the event that Client selects a vendor other than ATCO I-Tek to perform such Tier 2 Services, Client shall pay ATCO I-Tek at the Time and Materials Rate for any incremental Services required from ATCO I-Tek to integrate such Tier 2 Services, or any Deliverables arising from such Services, into the Tier 1 Services and any Tier 2 Services provided by ATCO I-Tek.

1.4 Tier 3 Services

Investment services is Strategic Planning, Business Planning and Business Improvement Processes. ATCO I-Tek is responsible for assisting the ATCO Group in the development of the ATCO Group corporate IT Plan that coincides with the Business Planning Process as a potential input to the aforementioned investment services. ATCO I-Tek will accomplish this role by assessing the ATCO Group's current information technology strategy, and by providing the CIO's and IT Governance office with proposals, which contain recommendations of what IT strategies could be implemented to bring the highest value to the ATCO Group. For future business opportunities, ATCO I-Tek will bring forward a business proposal documenting the risks of proceeding and the tangible benefits.

ATCO I-Tek follows the Information Technology Infrastructure Library (ITIL) processes to provide quality control for hardware and software management. These processes cover a number of areas focusing on IT service delivery and support.

As it pertains to IT service delivery, ITIL provides a management framework. These areas include:

- **Service Level Management**
- **Capacity Management**
- **Continuity Management**
- **Availability Management**
- **IT Financial Management**

As it pertains to IT service support, ITIL defines management practices that enable ATCO I-Tek to effectively provide Services. These practices include:

- **Configuration Management**
- **Incident Management**

- **Problem Management**
- **Change Management**
- **Release Management**
- **Service Desk**

ATCO I-Tek follows industry standard development practices during the development, enhancement and maintenance of applications. There will be 3 facets to quality management:

- **Quality planning** – identifies which quality standards are relevant to the project and how to satisfy them. These standards will be identified during the project initiation workshop and will be built into the project plan.
- **Quality assurance** – involves the periodic evaluation of overall project performance so that the project will satisfy the relevant quality standards.
- **Quality control** – involves monitoring specific project results so that they comply with relevant quality standards while identifying ways to improve overall quality.

These processes will be used in conjunction with Clients input to produce the quality management plan, quality improvement, acceptance decisions and process adjustments throughout the project lifecycle. Some key quality control mechanisms are:

- Project management
- Quality Planning
- Client involvement – part of the development team and regular discussions during the development releases
- Short release/delivery timelines
- Audit reviews
- Pair programming
- Acceptance testing
- Functional walkthroughs
- Development Standards
- Client Quality Reports (scorecard to measure Client's satisfaction)
- Completeness and Correctness checklist

2.0 Definition of Services

2.1 Planning

Tier	Category	Major Scope Items not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)s	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	ATCO Group Information Resource Planning for Information Technology	• Define requirements (ATCO & ATCO I-Tek) • Prepare workload plan (ATCO & ATCO I-Tek) • Obtain resources (ATCO I-Tek)			Prepare as required	Approve plans & schedule	Included in all Rates
3	IT Strategic Planning	• Create 3 year technology plan including architecture & business improvement opportunities • Directed toward senior management and meeting their long term business goals	High level progressive technology plan	Strategic business, technology and/or architectural planning as requested and approved by the Client.	Planning of efforts are guided by this plan	Obtain Subject Matter Expertise as applicable	Time and Materials Rates
1	IT Budget Planning	• Prepare estimates for projects & operational costs for Tier 1, 2 and 3 activities requested.	Yearly		Prepare budget in concert with Strategic plan & reflects current fiscal position of ATCO Group of companies	Lead, prioritize & approve budget plan	Included in all Rates
1	IT Operational Planning	• Prepare and Manage a Yearly Operational Plan that will provide monthly operational status reports to the CIO's Office. • Development of action plans for the acquisition & deployment of resources to carry out the strategies identified in the Strategic Plan • Includes plans dealing with the day to day operations that are necessary for accomplishing the action plans • Analyze, report, and forecast resource usage to predict future computing capacity requirements. • Provide ATCO with future Technology direction for connectivity, interoperability, and manageability. • Provide coordination of preventive maintenance services only for those assets that are managed and operationally controlled by ATCO I-Tek that support ATCO.					Included in all Rates

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2.1 Planning – continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	IT Feasibility Studies	• Prepare an Opportunity assessment to warrant further investigation or initiation of a proposal or feasibility study. • Match project proposals to the needs of the business to identify the high savings initiatives or improvements in the current process • Complete all the standard components of a Feasibility Study (Business Area Analysis, Opportunity Assessment, Cost Benefit, Alternatives, Project Definition)			Prepare the plan	Approve plan & schedule	Time and Materials Rates

2.2 Financial Account Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Financial Billing	• Prepare and manage all aspects of the financial billing process as it relates to Information Technology services provided by ATCO I-Tek.	Billing at a level and content not to exceed billing in place at Effective Date		Provide correct billing for services provided.		Included in all Rates

2.3 Standards

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	IT Standards	• Create standards with ATCO business in mind, for the effective development, maintenance & operation of the ATCO Group information & Systems services • Assist the CIO's Office in the formulation of Service Policies, standards & procedures for the development of strategic & operational plans that enhance the use of information technology.		Detailed strategic plans that align with business plans – Time and Materials Rates	Recommend the standards Inform ATCO of non-adherence to Standards	Prepare Service Policies & approve standards Approve all non-standard requests	Included in all Rates

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2.4 New Technology & Infrastructure

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	New Technology	• Evaluate new products or services • Establish new product standard if necessary • Provide new products that are cost effective & fit into overall technology infrastructure environment. • Prepare a conversion strategy and costs • Develop & implement evaluation & testing processes • Obtain Business case approval prior to implementation • Work with the CIO's Office.	All hardware & software including infrastructure (may result in new service offering) New Technology evaluations will be determined and agreed on through the Workload Plan Process. Number will be limited to resource and skill availability.		Inform ATCO of non-adherence to Standards Provide proper testing & change management as part of general practices & built into the methodology	Review & audit standards when required Approve all non-standard requests Validate requests for implementation of non-standard products Identify new service requests.	Included in all Rates
1	Release Management	• Release Management is the management and structured release of workstation, server, and network software standards that are mutually determined by ATCO and ATCO I-Tek, within the server environment. • Deploy all standard workstations through the Release Management function with the standard set of software applications as mutually determined by ATCO and ATCO I-Tek. • Create, maintain and periodically update a master release schedule with regard to the Third Party Software that exists in ATCO's environment. • Keep a release calendar and communicate information to ATCO. • Set tentative release dates for new rollouts that will be determined jointly with ATCO. • Mutually define release standards with ATCO. • Put an integrated process in place across the Release Management and Technology Planning functions.			Provide Client with the proposed project and timing	Review and approve projects	Included in all Rates

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2.5 Customer Support Centre

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Customer Support Centre	• A "single point of contact" for the Client. If the CSC support analyst cannot resolve the problem/request, a service ticket is created and assigned to the appropriate support group. • The Customer Support Centre can be contacted by telephone and by email for non-critical situations	ATCO I-Tek's normal business hours are from 08:00 to 17:00. Monday through Friday CSC staff are available "On-site" Monday to Friday 07:00 until 17:00 ("**On-site**" means that there is a support analyst in the ATCO I-Tek CSC office). After hours, on weekends and statutory/Client holidays, CSC support is provided through our message and paging System. 24 hours a day, 7 days a week (7x24) coverage to respond to priority Client questions, requests, problems or difficulties in using Information Systems services.			System specific "How To" training Use of after business hours services to be restricted to business critical and essential as defined by the Client	Included in all Rates
1	Reporting	• Provide statistical reports on Service Tickets as required by Service Level Agreement	Monthly.	Additional reporting and investigation as requested			Included in all Rates
1	Problem Management	***Problem Management*** • Manages availability, responsiveness, and serviceability. • Every trouble ticket will have a priority code assigned as agreed to with the caller based on the nature of the situation and the impact of the problem. The impact to availability, on-line response time, usability of an application, integrity of an application, impact on the business, impact on the Clients, the number of people affected, are all considered when assigning the priority code. ***Problem Communication and Escalation*** • Follow a documented problem communication and escalation procedure. See Appendix F (Priority Level Definitions & Notification Escalation Service Request Process) of Schedule A (Service Levels) – Priority Level Definitions & Notification Escalation.	Application has a separate process for problem management.	Problems with Non ATCO I-Tek equipment	To take ownership of problems & resolve to the Client's satisfaction		Included in all Rates

2.5 Customer Support Centre- continued

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Problem Management – continued	• Immediately inform designated Client contacts (Client governance representative and/or application coordinators) of problems assigned critical priority that affect the Client • Concerns about quality of service should be first communicated to the support analyst providing the service. If the concern is not resolved, or there is an issue around interpretation of the Service Level Agreement, contact the Supervisor, Customer Support Centre. ATCO I-Tek will address such quality concerns with the appropriate Client governance group and/or the CIO Office. If concerns are not resolved, escalation will continue to the ATCO I-Tek Designated Manager ***Problem Post-Analysis*** • All problems are recorded with information on the nature of the problem, the impact and the resolution. • The problem database is analyzed to determine the nature of problems or the service ticket trends and what proactive efforts would eliminate the root cause of the problems. Root cause analysis is performed as part of the post mortem when a major problem (Critical or High) has occurred. This effort is focused on determining the actual cause of the problem and developing appropriate corrective action.					

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2.5 Customer Support Centre- continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Change Management	• Change Management will be provided to maintain availability, responsiveness and serviceability for the ATCO Group of companies enterprise computing environment • When the Client or ATCO I-Tek deems that a change to an application, computing tool or service is required, to meet a new business need, a technical need or resolve a problem, a process is followed to define the requirements; complete an impact analysis, identify options; and a costing of service and financial justification • A record of changes is created to notify all potentially affected parties, to co-ordinate changes, to reduce conflicts, and to provide a standard methodology. • Provide change management reports. • Pre-determined and planned outages will be communicated to Clients. • Key contact people will receive a weekly schedule of all scheduled outages by electronic mail. • Clients can call the Customer Support Centre to receive information about any scheduled outages. • All new application releases are tested and the ATCO I-Tek staff is briefed for support of their use before the changes are implemented. This will provide appropriate communications between ATCO I-Tek and the Client. ATCO I-Tek must arrange Service Requests requiring Change Management to be addressed in the acceptable timeframe required by the Client.	**Change Windows** Changes are implemented according to the following scheduled "Change Windows": REGULAR SUNDAY: Each Sunday from 15:00 to 02:00 Monday. Easter long weekend (36 hours) from Saturday, 12:00 Hours through Monday, 0:00 Hours (midnight) Thanksgiving long weekend from (21 hours) Saturday, 06:00 Hours to Sunday, 03:00 Hours	Individual workstation specific changes do not necessarily follow the Change Windows schedule.	Pre-arrange scheduled downtimes (Change Windows) between ATCO I-Tek and the Clients. Notify the Clients of the planned outages and exceptions or delays to the changes. Endeavor to minimize changes outside the Change Windows.	In order for change to be managed by ATCO I-Tek, Clients must not move, install or remove hardware or software or make configuration changes. Agreement for changes will not be unreasonably withheld. ATCO Clients are responsible for reviewing change notification and raising any issues or concerns with ATCO I-Tek.	Included in all Rates

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2.5 Customer Support Centre- continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Change Management - continued	***Change Lead-time Exceptions*** • Sufficient lead-time for changes are required as outlined in the Services Level Measurements document. The nature of some changes may extend the lead time requirements if the changes require work or equipment from Third Party suppliers. • Change schedules can be negotiated considering the needs of the Clients, their business cycles, the impact on the business, short and long-term preventative maintenance and the consequences of not performing the change. ***Year-end Freeze*** • To facilitate completion of year-end processing, a no-change period (year end freeze) is instituted from late December to mid January. The period generally begins after the third Sunday Change Window in December and ends before the second Sunday Change Window in January. • Changes during the year end freeze can be negotiated considering the needs of the Clients, their business cycles, the impact on their business, impact on other Companies on the ATCO Network, and the consequences of not performing the change. During the year-end freeze, ATCO I-Tek and ATCO senior management must approve all changes. • ATCO I-Tek will work with the telecommunication service providers to minimize telecommunications company network changes that occur within this window.					

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2.5 Customer Support Centre- continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Change Management - continued	***Application Changes*** • Application changes are made according to the schedule directed by the Client of the respective applications. For the mainframe environment this may involve a release management approach or be single change implementations. • Log all changes that impact the Client environment					
1	Corrective Action Team (CAT)	• A process that brings a cross functional team together to manage a major outage, on-going issue, or problem to resolution					Included in all Rates
1	Client Satisfaction	• Confirm with Client that problem was resolved to Client satisfaction				Client to respond to request for feedback.	Included in all Rates

2.6 Security Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)s	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Security Management	• Provide services to maintain and manage data and computer access security. Security Management and Framework Standards are contained in Appendix B (Security Framework Standards) of Schedule A (Service Levels). • Manage user ids • Monitor, report & control access violations • Follow all procedures for the administration of data security • Manage security Service Policies & procedures as approved by the ATCO Group • Investigate security breaches • Implement corrective actions for security breaches • Provide Security and Documentation for the Logical Network.		Data and ID access changes as a result of major dept. / Corporate restructuring	ATCO I-Tek to recommend Service Policy and security standards See Security Framework Standards in Appendix B (Security Framework Standards) of Schedule A (Service Levels)	ATCO to approve Service Policy and security standards See Security Framework Standards in Appendix B (Security Framework Standards) of Schedule A (Service Levels)	Included in all Rates

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2.7 Asset Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Purchasing and Asset Refresh	• Manage the order process (i.e., from the inception of a new purchase through the installation and user acceptance of the product). • A quarterly installation plan, based upon the Business Plan, will be established and agreed to with each Client for new, replacement, and re-deployed equipment. Exceptions and changes to the plan will be factored in as required. ***Standards Management/End-User Consultation*** • Provide and maintain an ATCO based standard and to assist end users in the proper selection of the standard workstation and network configurations and services. The intent will be to provide equipment that is consistent with the standards of the Client to minimize the costs and maximize the compatibility with other corporate Systems and equipment prior to implementation • Document and communicate problems with processes, product availability concerns or any other related issues to ATCO management. • Provide physical identification of assets. • Maintain configuration and usage profiles of the equipment. • Maintain inventory of spare parts for critical components. • Analyze the implications of using older equipment and migrating to new equipment. Plan the migration strategy. • Complete a recommendation that meets the Client's business needs.	Workstation installs and technology refreshes are included in the PC support fees. . ATCO I-Tek provides a comprehensive asset management program for all leased devices. Asset management includes recommendation and selection of standards, vendor management, procurement, tagging, Client assignment, tracking, refresh, removal, decommissioning and disposal.	For adds / moves after regular ATCO I-Tek business hours, as agreed to by Client, incremental charges will apply. All other Moves/Adds/Changes to workstations and voice. Major Technology and architecture changes.	Identify when deviations from standard products are requested. Verify request to ATCO's standards. In consultation with Clients, provide a refresh strategy that addresses Client needs & review process as required. ATCO I-Tek develops annual refresh schedules and provides these reports to the Clients.	Will be responsible for having a Service Policy around the purchase of non-standard software by a user Review & audit processes. Approve and adhere to standards, as applicable.	Included in Lease Rates

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2.7 Asset Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Purchasing - continued	***Asset Management*** • Manage and maintain asset information for software, hardware and network components (e.g. location, model type, serial number, user, and Client). • Record purchasing information for each asset (e.g. manufacturer, vendor, cost, and warranty information). • Record maintenance agreement information. • Maintain and manage software-licensing information. • Report/query on replacement cost for all assets. • Plan moves and track the components and workstations that require connection to the network. • Provide asset-reporting information for budget and capacity planning purposes. ***Workstations*** • Plan, test, acquire, implement, support, maintain, re-deploy, and ultimately replace and retire the equipment, while following the consolidated technology specifications (see Technology Roadmap). • Work with individual Client to plan for technology as required to meet new and growing business requirements. • Properly test equipment to identify any issues and make necessary adjustments prior to implementation. • Maintain the equipment in proper working condition and to provide any support as required to fix problems as they occur.	Specified bandwidth of software products	Above bandwidth volumes			

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2.7 Asset Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Purchasing - continued	• Work with Representatives of the individual Client companies to determine the best place to deploy the new technology. In general, this means that the new equipment will be deployed to a Client with higher relative demand and the existing equipment will be "cascaded" to the lower end user, whose machine will, in most cases, be targeted for disposal. Only one cascade will be allowed per refresh deployment.				Notify ATCO I-Tek of all cascades prior to monthly schedule being finalized. Notify end users of cascaded hardware requests. Approve all cascades.	
1	Inventory	• Maintain & track an inventory of hardware & software • Log all adds, moves, repairs & retirements of assets • ATCO I-Tek will take appropriate measures to validate that the physical existence of assets is accurate and complete. The assurance can be derived through physical review of the employment of appropriate software tools.	.	Licenses acquired by Client are not managed by or the responsibility of ATCO I-Tek. In the event that the Client moves hardware from one location to another location without enlisting ATCO I-Tek staff, that Client will be charged Time and Materials Rates to identify the movement and correct all asset information on that asset.	Provide inventory Systems & associated processes to provide accurate inventory. ATCO I-Tek tracks software to provide software license compliance. All software that is purchased through and installed by ATCO I-Tek will be managed and tracked to provide license compliance.	Enforce compliance with inventory management processes (e.g. movement of all computing assets must be handled by ATCO I-Tek staff to maintain inventory information and maintain warranty). Licenses that are acquired or installed by the Client are the responsibility of the Client.	Included in all Rates.
1	Reporting	• Financial reporting. • Reports on Service Levels and delivery measurements. • Auditing/QA reporting. • Tier 1 enhancement and maintenance priority and status reporting. • Tier 2/3 project management and status reports. • Provide hardware & software inventory reports • Maintain cost information on all computing assets • Track software licenses.	Reporting as provided at Effective Date	New reports that will be provided at Time and Materials Rates.	Track disposal of assets	Identify reporting requirements	Included in all Rates.

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2.8 Disaster Recovery

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Disaster Recovery - Mainframe	In a disaster situation, the primary goal of ATCO I-Tek is the restoration of centrally managed Data Processing services, using the established Disaster Recovery plan. • Provides services to recover production processing and data in the event of a major disaster impacting the production environment (as outlined in Appendix C (Disaster Recovery Methodology) of Schedule A (Service Levels). Disaster Recovery is distinct from Operational Recovery in that the host site is assumed to be incapacitated. • Disaster recovery/continuity planning deals with technical Systems issues, such as System fault tolerance and System and network redundancy, backup, and recovery, and addresses the ability to recover servers, workstations, applications, and the support personnel to provide such services. • ATCO I-Tek will provide the level of disaster recovery as identified with, and agreed to with Clients. • Create and maintain a plan (as outlined in Appendix C (Disaster Recovery Methodology) of Schedule A (Service Levels) for recovery from a disaster or major outage for critical applications. ***Enterprise Server and ATCO Network*** • Disaster Recovery for the server and network is the restoration of mainframe services and products to their original operational state after they have been disrupted by a natural or man-made disaster. • Disaster Recovery Planning is the overall process for developing practices and procedures to allow continuous System service. Specifically, the Disaster Recovery service provides the execution of predefined Disaster Recovery Plans	Time spent on mainframe disaster recovery plan is approximately 2500 hours per year. Restore host System services within 72 hours following a declared disaster. Recover network connectivity to the host within 72 hours following a declared disaster. Restore all application data to the last backup immediately prior to the disaster. The assumed loss of System updates/data is up to 24 hours; since identified backups are done on a daily basis and stored off-site. This is shortened in some specific cases through additional backup strategies. Although System services will be restored within 72 hours, System operations may be performed remotely (from a recovery center in Calgary, Toronto or Chicago for example). It is assumed that the distance will present numerous telecommunications, response time and logistical problems. Printing and inserting ATCO-CIS statements will be performed by a business continuity vendor. All other reports will be printed at ATCO I-Tek's Calgary data centre and transported by courier to Edmonton. Depending on refurbishment requirements and equipment availability, normal operations may be restored within 6 months.	Client initiated Disaster Recovery and work area recovery testing projects are excluded.	Responsible for disaster recovery planning for those computing resources managed and supported by ATCO I-Tek data center site	Approve plan Each Client must review backup, retention, and off-site storage specifications for their application Systems on a regular basis, particularly in cases where tape is used as a routine storage media. Deficiencies identified in this review must be communicated to ATCO I-Tek. The Client's responsibility under the ATCO I-Tek recovery plan is to bring forward, re-enter and synchronize application data. The Client must validate the recovery.	Included in all mainframe Rates

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2.8 Disaster Recovery - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Disaster Recovery – Mainframe continued	• ATCO I-Tek has developed, tested, and documented a disaster recovery plan for the enterprise server and ATCO network environment. The disaster recovery plan is tested annually.	ATCO has a disaster recovery plan that encompasses its existing enterprise server (mainframe). This plan includes a recovery of mainframe application source code, data, and hardware, network recovery; identification of hardware & software replacement sources; identification of disaster teams with specific duties assigned; and an execution of the plan as part of a test.			Provide a key contact person who will provide guidance and information to support the work performed by ATCO I-Tek. Participate in annual disaster recovery exercise and sign-off on the result.	
	Disaster Recovery - Distributed Infrastructure	This service provides disaster recovery for the distributed computing and network infrastructure that is required to support business applications in the event of a disaster. The distributed infrastructure disaster recovery service is based on a recovery time objective (RTO) of 72 hours (determined by the Clients as a result of their Business Impact Analysis). The disaster scenarios include the Edmonton and Calgary ATCO Campus sites. The following are included: • Internet Web Access, Email Routing, VPN, Windows Domain Authentication, Anti-Virus Protection – recovery time objective (RTO) is 0 hours and the recovery point objective (RPO) is 24 hours. • Internet & Firewall, Internet Web Sites, Intranet Web Sites – recovery time objective (RTO) is 24 hours and the recovery point objective (RPO) is 24 hours. • Software Distribution – recovery time objective (RTO) is 48 hours and the recovery point objective (RPO) is 24 hours.	The distributed infrastructure disaster recovery service has the following key elements: • The data centre facilities will be leveraged across two locations that meet distance criteria that mitigate the risk of a disaster hitting both locations. • A second, active Internet infrastructure will allow Internet access to continue with minimal interruption after a disaster. The infrastructure includes the protection mechanisms necessary for secure communications such as boundary router, firewall protection, and intrusion detection monitoring. The connection will support Virtual Private Network (VPN) services including the VPN Remote Client service used by ATCO regional offices to connect to the ATCO corporate	Planning for resumption of business functions. Clients are responsible for planning how they would continue their business after a disaster. Pre-designated work recovery areas where Clients can resume their business functions. However, on a per company basis, ATCO I-Tek can work with the Clients to address a recovery strategy that considers requirements for network connectivity, telephones, workstations, printers and faxes. A separate proposal will be created as determined by each Client company. Operational recovery is related to but separate from disaster recovery. In the event of a disaster affecting servers located outside the Calgary and Edmonton data centres, recovery will be completed using operational recovery procedures in either Calgary or Edmonton.	ATCO I-Tek will provide disaster recovery teams for the distributed environment. Each team will create and maintain their own component of the complete disaster recovery plan and participate in the annual exercises. At time of disaster, ATCO I-Tek will invoke their disaster recovery plan to recover the distributed infrastructure.	Notification to ATCO I-Tek regarding any required changes as a result of business changes.	Distributed Infrastructure DR Fee Net New - Statement of Work

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		• Anti-virus Administration, Outlook, File Servers, Print Servers, Distributed Applications – recovery time objective (RTO) is 72 hours and the recovery point objective (RPO) is 24 hours.	network. • A distributed server-based tape back-up and recovery infrastructure. Data for the distributed environment will be backed up to tape and the tapes will be stored off-site. • For infrastructure services that are provided by more than one server (primary and secondary), the secondary server will be located in an alternate site. Disaster recovery plans will be created and maintained by ATCO I-Tek. An annual exercise will be set up and undertaken with participation by ATCO I-Tek and the Clients. A post-mortem will be completed after each exercise that will document opportunities for improvement.	Data on workstation hard drives is not backed up and will not be recovered. Edmonton and Calgary PBX. AS/400 Server Recovery. In the event of a disaster, expenditures for incremental labour, travel and materials are not included in the prices in this service offering and will be billed on a time and materials basis at the then current pricing. Any work performed other than that by ATCO I-Tek. Significant infrastructure and architectural changes are not accounted for in the fees.			
	Disaster Recovery - Distributed Critical & Essential Applications	This service provides disaster recovery for the critical and essential business applications in the event of a disaster. The critical and essential applications disaster recovery service is based on the recovery time objectives (RTOs) determined by the Client for each critical and essential business application through their Business Impact Analysis.	Determine Client applications priorities ensuring workflow and interdependencies are captured. Complete architecture review and finalize solution in line with business requirements. Establish Recovery time and Recovery point objectives in line with business objectives. Create and document disaster recovery plans for each application based on recovery time objective. Implement the disaster recovery solution for each application: • Set up server	Planning for resumption of business functions. Clients are responsible for planning how they would continue their business after a disaster. In the event of a disaster affecting application and data servers located outside the two main data centres, recovery will be completed using operational recovery procedures in either Calgary or Edmonton. Data on workstation hard drives is not backed up and will not be recovered. In the event of a disaster, expenditures for incremental	ATCO I-Tek will set up disaster recovery teams for the distributed environment. Each team will create and maintain their own component of the complete disaster recovery plan and participate in the annual exercises. At time of disaster, restore the production database from the copy on the DR server or retrieve the offsite tape and restore the operating system, application and database onto the DR server.	Provide a key contact person who will provide guidance and information to support the work performed by ATCO I-Tek. Participate in annual disaster recovery exercise and sign-off on the result. At time of disaster, Clients will bring forward, re-enter and synchronize application data.	Critical and Essential Applications DR Fee Net New - Statement of Work

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
			hardware at the ATCO disaster recovery site. • Execute a nightly process to either copy and import production application data onto the DR server or create a backup copy of the production server on tape and send offsite. Conduct an annual disaster recovery exercise with the Clients to test the recovery plans for each application. Document the results including recommendations for improvement. Review with Clients, as appropriate, to determine changes. Monitor the application, so that changes to the production environment, prompts a review and potential change to the disaster recovery solution. Review and maintain the disaster recovery documentation on an on-going basis. Maintain the DR servers on an on-going basis to be consistent with the production environment (i.e. security patches, etc.).	labour, travel and materials are not included in the prices quoted in this SOW and will be billed on a time and materials basis at the then current pricing. Any work performed other than that by ATCO I-Tek and its subcontractors. Major hardware/software upgrades or configuration changes. Gap analysis between disaster recovery and business continuity plans. ATCO I-Tek will work with the Clients, on a per company basis, to validate that their business continuity plans address a recovery strategy that considers requirements for network connectivity, telephones, workstations, printers and faxes. A separate proposal would be created as determined by each Client.			
	Disaster Recovery - Distributed - Remaining Applications	This service provides disaster recovery for the remaining business applications in the event of a disaster. The remaining applications disaster recovery service is based on the business applications that were not identified as critical or essential. Two recovery time objectives (RTOs) were established for this service -- 10 Days and Best Effort. The Clients verified their	Determine Client applications priorities ensuring workflow and interdependencies are captured. Complete architecture review and finalize solution in line with business requirements. Maintain disaster recovery plans	Planning for resumption of business functions. Clients are responsible for planning how they would continue their business after a disaster. In the event of a disaster affecting application and data servers located outside the two main data centres, recovery will be	ATCO I-Tek will set up disaster recovery teams for the distributed environment. At time of disaster, retrieve the offsite tape and restore the operating system, application and database onto the DR	Provide a key contact person who will provide guidance and information to support the work performed by ATCO I-Tek. Participate in annual disaster recovery	Remaining Distributed Applications Fee Net New - Statement of Work

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		specific business applications and determined the appropriate recovery time objective for each.	for identified applications based on recovery time objective. Implement the disaster recovery solution for identified applications: • Set up server hardware at the ATCO disaster recovery site in accordance with the chosen disaster recovery solution. • Create a backup copy of the production server on tape and send offsite. Conduct an annual disaster recovery exercise with the Clients to test the recovery plans for identified applications. Document the results including recommendations for improvement. Review with Clients, as appropriate, to determine changes. Monitor identified applications, so that changes to the production environment, prompts a review and maybe a potential change of the disaster recovery solution. Review and maintain the disaster recovery documentation on an on-going basis. Maintain the DR servers on an on-going basis to be consistent with the production environment (i.e. security patches, etc.).	completed using operational recovery procedures in either Calgary or Edmonton. Data on workstation hard drives is not backed up and will not be recovered. In the event of a disaster, expenditures for incremental labour, travel and materials are not included in the prices and will be billed on a time and materials basis at the then current pricing. Any work performed other than that by ATCO I-Tek. Major hardware/software upgrades or configuration changes. Gap analysis between disaster recovery and business continuity plans. ATCO I-Tek will work with the Clients, on a per company basis, to validate that their business continuity plans address a recovery strategy that considers requirements for network connectivity, telephones, workstations, printers and faxes. A separate proposal would be created as determined by each Client.	server.	exercise and sign-off on the result. At time of disaster, Clients will bring forward, re-enter and synchronize application data.	
1	Disaster Recovery - Exercises	• Plan, conduct and evaluate disaster recovery exercises. • Schedule a date for the exercise and advise Governance representatives and Client participants.	Annual exercise.			Client participation in the exercise(s) is required to validate recovery of business processes. Determine Client	Included in all Rates

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		• Determine scope, objectives, impacts and logistics. • Review I-Tek and Client application test plans. • Schedule evaluation sessions and prepare reports of the disaster recovery exercise.				participants	

2.9 Computer and Facilities Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)s	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Computer and Facilities Management	• Provide facility management services for the computer facilities covered by the Service Level Agreement. • Usage monitoring and capacity planning. • Connect hardware and software to data and voice networks. • Provide advice on enhancements to software, hardware and communications to keep in step with standards. • Provide security and computer room environmental requirements that are met & maintained • Work with hardware vendors & Property Management during hardware installs to meet all physical requirements. • Maintain Computer room layout & cabling diagrams • Maintain electrical & mechanical profiles that outline power and cooling availability & usage. • Provide fire protection Service Policies, procedures & equipment that is in place & operational	Main campus buildings (in Edmonton & Calgary)		Where such facilities are in locations outside the ATCO I-Tek Supported Locations, ATCO will work with ATCO to define specific facilities responsibilities.	Where such facilities are in locations outside the ATCO I-Tek Supported Locations, ATCO will work with ATCO I-Tek to define specific facilities responsibilities. Site specific requirements are the responsibility of the Client. On-site ATCO staff will continue to provide ATCO I-Tek staff with ad hoc assistance where	Included in Rates

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)s	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
						required at remote sites	
1	Power outages	• Coordinate with building owners when known power outages are scheduled • Create plan with ATCO I-Tek support staff to minimize effect of outage • Communicate instructions to Clients to minimize effect of outage	Main campus buildings (in Edmonton & Calgary)				Included in Rates

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2.9 Computer and Facilities Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Test Lab	• Test Lab is the physical technical environment to be used solely for proof of concept activities. • ATCO I-Tek will configure and maintain the test lab. • Perform a technical and basic functional test of proposed new approved products list items to test compatibility with the existing infrastructure and to attempt to minimize problems before installation into the production environment • Analyze infrastructure impact of upgrades and changes in the applications based on input from standard suppliers and developers.					Included in Rates

2.10 Contract Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Contract Administration	• Manage Master Services and Service Level Agreements • Manage Third Party contracts for software/hardware and services included in this SLA • Monitor compliance with contractual obligations. • Monitor the performance of contractors to fulfill obligations. • Maintain contract records. • Maintain vendor relationships.	Contracts covered under the Service Level Agreement.	Contracts negotiated and executed by and for ATCO Clients.	Maintain standards and Service Policies for the procurement of IT related licenses, equipment and services.	Enforce compliance with contract standards and Service Policies including scope of use and other contractual limitations.	Included in Rates up to the specified Bandwidth

2.11 Consulting

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
3	Business re-engineering for a complete business unit	• Provide re-engineering services				Define Requirements	Time and Materials Rates

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2.11 Consulting – continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
2	Re-engineering for business functions affected by a development project	• Provide re-engineering services as part of any new development project, if a requirement by the business unit.			Business re-engineering included in all major development projects	Business re-engineering included in all major development projects	Time and Materials Rates
1	Client Liaison	• Provide consulting services to the Client • Manage Client expectation and satisfaction • Undertake changes that have the Clients' interests in mind • Provide interface to ATCO Clients in relation to the shared & dedicated facilities & services within ATCO Group • Provide a single point of contact for Client requests	Consulting services are limited to initiative of 7 hours or less up to a maximum of 1500 hours per calendar year.		Make Clients aware of processes & procedures for interfacing with ATCO I-Tek personnel.	Shared responsibility to follow processes & procedures	Time and Materials Rates for Consulting services of more than 7 hours
1 & 2	Project Leadership	• Undertake project leadership and management of projects on behalf of Client • Provide a methodology for projects			Provide project leaders that are adequately trained in project management	Approve and fund projects.	Time and Materials Rates
1	Hardware / Software Product Consulting	• Provide consulting to the ATCO Group concerning new Hardware / Software technology • Adhere to standards					Time and Materials Rates

2.12 Training

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Software	• Provide consulting & advice on available training for software products		Client Training Course Fees. Any setup costs for customized training will be billed to the project.	ATCO I-Tek will recommend training for Clients.	Provide Clients with training on all software products required to perform their duties.	Specified Expense

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2.13 Mainframe Management & Support

Production Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Batch & Online	• Manage and run Batch & On-line jobs. • Maintain libraries of source & object code for production applications • Maintain JCL libraries • Support batch stream submissions, job checking & clearing • Provide all on-line teleprocessing packages that are available when required • Provide and make available the required tapes for on-line & batch processing • Startup/shutdown databases as required to maintain online & batch applications • Manage automatic transmission of System information as per Client schedule • Maintain current level of lights-out mainframe operations • Maintain operations Documentation • Maintain operators log • Open & close service tickets	Critical financial and data transmissions			Define requirements (or changes to requirements)	CPU Rates
1	Job Recovery	• Provide standby/call-back support • Provide on-call support for emergencies • Notify Clients where required • Monitor/restart jobs in failure situations • Maintain job recovery manuals			Maintain & monitor backup/recovery products Compliance with Service Levels		CPU Rates

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2.13 Mainframe Management & Support – continued

Production Management – continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Operational Recovery	• ATCO I-Tek provides services to recover production processing and data in the event of an outage causing any impact to the production environment or a production application. Operational Recovery is distinct from Disaster Recovery in that the computing facilities are assumed to be largely intact and operational. Data retention is based on Client requirements. • The recovery of operational Systems, software tools, application software and application data is dependent on the latest backups. During the on-line processing of the applications, the database updates and transactions are logged. In the event of an outage, they can be used to re-establish part of or a full day's on-line processing.	***Enterprise Server*** ATCO I-Tek responds to a crisis situation requiring operational recovery of system processing capabilities recovered in 24 hours. 100% of stored data is recovered in 24 hours. Fully synchronized production is recovered in 48 hours. (*Depends on the database management concerns: recovery requirement, priority of data, backup location, backup type, backup currency, synchronization, the amount of data, server location, and capacity)* Client involvement to verify data and bring the data to a known, synchronized and accurate state. Data recovery is limited to 6 weeks (unless otherwise agreed to with Client).		Compliance with established Service Levels	Verify System and application backup and archive requirements to meet business needs. Verify the System integrity for all operational recovery events.	CPU Rates
1	Storage Management	• Configure & maintain Systems Managed storage environment • Support all storage management software products • Monitor device activity, response time & capacity • Perform data management on System volumes (i.e.: Backup, Archiving) to meet Service Levels requirements. • Send tapes offsite for storage (used for Disaster Recovery & archiving)		Client requested restores.			Data Storage Rates

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2.13 Mainframe Management & Support – continued

Production Management – continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Performance Tuning/Capacity Planning	• Customize software performance tools to provide appropriate reporting • Provide usage & performance exception reports & charts • Maintain two (2) years historical processing usage data & statistics • Monitor System performance & perform corresponding tuning					Included in all Mainframe Rates
1	Reporting	• Supply reports of inactive managed mainframe data sets to Clients on an ad hoc basis				Client is responsible for deleting unwanted datasets.	Storage Rates

Print Management

1	Output & distribution	• Manage output distribution • Print all output on schedule and meet quality control standards & user expectations • Manage report distribution & electronic storage of output • Manage distribution of output, shrink wrapping, binding, decollating, bursting, etc • Maintain Systems & hardware required to manage mainframe output & distribution of that output • Define print requirements • Acquire & maintain print stock, warehouse stock • Monitor spools • Purge outdated & unwanted output		Form costs		.	Print Rates

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2.13 Mainframe Management & Support – continued

Print Management – continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Mainframe Printers	***Enterprise Server Printing*** Generally, enterprise server print services are measured from the end of the processing job creating the report, the amount of printing required and the type of printing required. • Manage printer environment • Configure standard printer • Configure & install specialized printer software • Test • Take out of service • Manage hardware upgrades • Monitor extended device interventions.	The production batch window is generally 18:00 - 07:00, Monday to Friday. Refer to Schedule A Appendix A for application specific batch windows. Due to the high volumes at month-end and year-end, specific print timeframes may need to be arranged and certain output scheduled to meet the Client and business needs.			The Client is responsible for collection and distribution.	Print Rates
1	Printing	• High Speed Electronic Printing					Print Rates

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2.13 Mainframe Management & Support – continued

Hardware & Software

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware	• Manage hardware • Evaluate, purchase, receive & test mainframe-related hardware • Install or upgrade hardware • Take hardware out of service • Activate tape library Systems • Verify accurate data retention in tape libraries • Maintain scratch tape pools & add new tape capacity when required		Impact from Tier 2 or 3 development projects will be assessed & pricing adjusted accordingly			Included in all Mainframe Rates
1	Software	**Software License Management** Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement. • ATCO I-Tek will determine requirements for meeting license agreements based on accepted industry standards to manage software. • Configure & install specialized mainframe software (including backup software) • Validate that all installed software is properly licensed • Take out of service	As required to maintain current Service Levels	Ongoing costs associated with End of Life products	Will make a best effort (over time) to reduce the number of software products in use	Will make a best effort (over time) to reduce the number of software products in use	Included in all Mainframe Rates.
1		**Software Upgrades** • Research upgrades or replacement products • Evaluate and test the upgrades • Plan implementation to validate software licensing • Evaluate technical capabilities • Installation meets requirements.					

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2.14 Workstation Management & Support

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Workstations	• Manage workstations and configurations. • Support ATCO's current technology standard. • The service guidelines listed by ATCO I-Tek and reproduced in this document are not complete, nor are they intended to be. • Follow ATCO I-Tek philosophy of supporting all the hardware and software in place.	PC workstations operating under standard workstation operating system will be configured in one of two profiles: type A or B. Type A provides the user with workstation administrative privileges Types B is the most prevalent configuration and is fully supported.	Standalone workstation support is not included in base support. If required will be completed per the established fees. Resolution of problems that resulted from Client having Administrative rights to their workstation.	ATCO I-Tek will recommend a Service Policy concerning the configuration of Type A or B Clients.	ATCO will approve the Service Policy on Client Type. ATCO will approve Client classification into Type A or B.	Workstation rates.
1	Hardware & software installs	• Hardware and software installation services support the installation and maintenance of distributed computing and network platforms and software. ***Site Preparation*** • Site preparation is the preparation of the physical equipment site prior to installation of a new piece of equipment. • Work with the ATCO Representatives to understand the current environment and determine additional requirements for hardware, software, power, communications wiring, and network connectivity. • Document all hardware, software, power, communication wiring, and network connectivity orders for the site preparation.	Configure standard build including CORE applications (operating system, email, word processing, spreadsheet, mainframe connectivity software, internet connectivity software, virus protection)	Configure, test & install specialized business software. Workstation backup and restoring of data		Compliance with Change Management Process.	Workstation rates.

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2.14 Workstation Management & Support - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware & software installs - continued	• Place all of the orders for the site preparations, with the proper Client approval. • In order to conduct the physical surveys of all hardware, software, power, communications wiring, network connectivity or other items, ATCO I-Tek will coordinate and gain access to all of the facilities during appropriate time frames (this could imply Business Day access to critical areas or after hours access). ***Onsite Staging and Integration*** On-site staging and integration is the inspection and setup of workstation in accordance with existing processes. • Recommend process changes to Client where appropriate. • Provide onsite and on-call technicians to perform staging and integration services. • Integrate and stage equipment and provide Client with a document certifying that the integration was completed according to existing ATCO I-Tek processes. ***Installation*** • Installation is adding hardware and/or software to the environment (workstation or shared resources), connecting to the applicable network, verifying general working condition of the hardware and/or software.				Compliance with Change Management Process.	Workstation rates.

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2.14 Workstation Management & Support - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware & software installs - continued	• Provide on-site and on-call technicians to perform server and workstation installation services for servers and workstation devices. • Provide a brief orientation (less than 10 minutes) for the end user on the basic functionality of the newly installed workstations. ***Move and Add services*** Move and add services are those activities to make updates to the ATCO network and workstation-computing environment. • Conduct a site survey to determine operational requirements and communicate any additional items required to support move, and add activity. • Disconnect a System at one location, reconnect at another location and provide functional testing after move, and add service activity verifying correctness of changes. Jointly with Client end users, determine and perform necessary back-ups of data files on workstations prior to any move or add service being performed. ***Virus Detection/Repair*** Workstation virus detection and repair addresses ATCO's need to safeguard data from damage by computer codes hidden in software that can corrupt and destroy valuable programs and data. • Provide detection and removal of viruses on workstations using current commercially available software. • Provide advice to end users on a regular and periodic basis relating to the identification, prevention and removal of potential virus problems. • Maintain current signature file with up-to-date virus signature information. • Maintain current virus detection					Time and Materials Rates

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		software code levels. ***Remote Workstation Management services*** Remote management service is accomplished through a software agent on the workstation that allows ATCO I-Tek to control the Client end-user's workstation, allowing a trained technician to perform hands-on investigation of a reported problem. • Provide remote control • Use the remote control capabilities as agreed to by ATCO. • Service Policy and process definitions will be completed and maintained. Communication to the participating Clients will be coordinated through the appropriate groups.					
1	Repair & Support	***Workstation Support*** Workstation support consists of the technical assistance or troubleshooting at a specific physical device when problems related to such device cannot be resolved through the use of remote diagnostic tools or through phone support. • ATCO I-Tek workstation support Service Levels will be based on the problem and priority criteria as outlined in the Service Level Measurements document. Remote Site Support ATCO I-Tek will continue to provide services to the various Client locations outside Edmonton and Calgary main building complexes. The services are provided using one or all of the following three scenarios:					Workstation rates

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2.14 Workstation Management & Support - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Repair & Support - continued	• Onsite staff services the specific site and surrounding area. • ATCO I-Tek contracts a local supplier to service the specific site and surrounding area. • ATCO I-Tek staff makes periodic and emergency site visits based on the need. ATCO I-Tek will continue to provide remote support in the same manner it is done as of the Effective Date of the Agreement. As technology changes, remote support requirements may change. ATCO I-Tek will recommend changes to Client to modify the Service Level agreement to reflect such changes. ***Hardware Maintenance*** Hardware maintenance, also known as "Break Fix," is the technical diagnosis and repair services for physical problems related to hardware (workstation, server, and network) components. ATCO I-Tek will continue to provide hardware maintenance to meet or exceed the Service Level Measurements**.** • Provide on-site and on-call technicians to perform server and workstation hardware maintenance services at the Service Levels defined by Client. • Troubleshoot and repair server and workstation hardware covered by the Service Level Agreement. • Maintain and/or coordinate adequate spare parts inventories to perform server and workstation hardware maintenance. • Abide by original equipment manufacturer (OEM) guidelines during the warranty coverage period. On-site Client staff will continue to provide ATCO I-Tek staff with adhoc assistance where required at remote sites					

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2.14 Workstation Management & Support - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Software	**Software License Management** Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement. • ATCO I-Tek will determine requirements for meeting license agreements based on accepted industry standards to manage software. • Validate that all installed software is properly licensed • Take out of service ***Software audit compliance.*** • ATCO I-Tek will own**,** manage and be responsible for third party software vendors and their respective software. • Record • Track • Dispose ***Software Upgrades*** • Research upgrades or replacement products • Evaluate • Test to confirm basic functionality. • Plan implementation to validate software licensing • Build package or evaluate technical capabilities • Install or upgrade	As required to maintain current Service Levels		Will make a best effort (over time) to reduce the number of software products in use ATCO I-Tek reserves the right to remove software until potential licensing issues are addressed.	Will make a best effort (over time) to reduce the number of software products in use Compliance with Change Management process. Enforce compliance with contract standards and Service Policies including scope of use and other contractual limitations. Provide Proof of Licensing for all software not purchased through I-Tek directly. Address potential licensing compliancy issues in a timely manner.	Workstation rates (Includes CORE Apps.) Business application service fees for all special software. Specified Expense and Time and Materials Rates for software above the applicable Bandwidth.

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2.15 Server Management & Support

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware and Software	• Evaluate, purchase and receive hardware and software • Configure and install server hardware, operating system and standard infrastructure software • Manage Servers and Configurations • Configure standard build • Configure & install specialized server software (including backup software) • House server hardware in a secure location and maintain existing UPS Systems. • Validate that all installed software is properly licensed • Put required wiring & protocols required for a server in place • Test to confirm functionality. • Take out of service	• House servers in a secure computing facility as outlined in Section 2.9 Computer and Facilities Management	New and improved business applications as a result of Tier 1 or 2 projects will be estimated and priced separately New hardware additions or upgrades will be estimated and priced separately			Workstation rates. (includes file, print services) Distributed Server Rates

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware and Software - continued	***Printer and Peripheral Device Definition Queue Management*** Printer and peripheral device definition involves the logical addition and deletion of printers and other peripherals to the network and the management of the print queue. • ATCO I-Tek is responsible for the remote configuration of network printers and print queues. ***Configure, Install, Move, Remove Network printers*** • Configure standard build • Configure & install specialized printer software • Enable printer drivers for appropriate users • Test to confirm functionality • Take out of service ***File services*** • ATCO I-Tek will configure the System disks to be used for operating system areas, swap or paging areas, an area for the system to use for temporary files, an application area, and user area.					

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2.15 Server Management & Support – continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware and Software - continued	***Naming Standard services*** Naming standard services is the establishment and maintenance of standards for names and addresses to provide consistency within the ATCO environment. • ATCO I-Tek will coordinate names and addresses to provide consistency within the environment and to provide Systems administration. Existing naming standards will be adhered to. ***Application Environment services*** Application environment services involve configuring the System software so that application software is able to execute. • ATCO I-Tek will test and maintain server integration and compatibility for any application additions and upgrades as included within the Service Level agreement. ***Virus Detection/Repair*** Server virus detection and repair addresses the Clients' need to safeguard data from damage by computer codes hidden in software that can corrupt and destroy valuable programs and data. • Provide detection and removal of viruses on servers using current commercially available software. • Provide advice to end users on a regular and periodic basis relating to the identification, prevention and removal of potential virus problems. • Maintain current signature file with up-to-date virus signature information. • Maintain current virus detection software code levels. • Provide the continuous monitoring and correction for viruses on shared servers.					

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Hardware and Software - continued	***Software Distribution*** Software distribution is the distribution of operating system and user application software throughout a specified Client's organization. • ATCO I-Tek will provide software distribution as mutually agreed by the parties. • Regular upgrade schedules and an annual upgrade plan will be completed by ATCO I-Tek. • Provide version management and inventory management of application updates.					

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		•					
1	Repair & Support	***Distributed Server services*** Maintain the distributed server hardware and software at the Service Levels defined in the Service Level measurements. Maintain hardware and software ownership responsibilities for those assets owned by ATCO I-Tek. Provide move and add activity for routine updates to the distributed environment. Where such activity results in changes to existing services or activities are larger projects, additional charges may apply. ***Performance Monitoring*** ATCO I-Tek will periodically gather performance and capacity data from these Systems and analyzing this data using a variety of tools. ***Lifecycle Notification*** Notify Client and recommend alternatives when distributed System hardware, hardware components or operating system software are no longer supported because they are considered obsolete by the manufacturer and/or Third Party maintenance vendor and cannot be procured or obtained in sufficient time to meet the required performance level.		New and upgraded business applications as a result of a Tier 1 or 2 projects will be estimated and priced separately.			Business application service fees for all special hardware and software services.

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Repair & Support – continued	***Operation and Administration*** • Monitor availability and reliability of the distributed server and production database/subsystems based on user feedback and problem resolution. Fluctuations and variances in available capacity are analyzed, diagnosed and corrected as necessary through appropriate priority level and in keeping with a cost-effective solution. The distributed platform will be available on a continuous basis except during Change Windows and back up of disk storage as scheduled. • Provide problem management to include identification, Documentation, communication, escalation, corrective action, confirmation, and measurement. All Service Level standards relative to problem management are based upon the definitions of priority • Provide problem management reports. The frequency of utilization reports will be determined by ATCO. • .All changes and updates are done in compliance with the change management process. • Provide data security, to the extent allowed by the operating software for the Distributed Systems including adding changing and deleting User access information, in accordance with ATCO's data security Service Policy. • Install operating system security patches and test integration and compatibility with server configuration	• Provide data security in accordance with ATCO's security Service Policy as outlined in Section 2.6 (Security Management) • Daily backups with offsite tape storage to provide operational recovery as outlined in Section 2.19 (Data Protection)				

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	– ***Production Control***	***Production Control*** Production control is the management and facilitation of production on the midrange server environment. Production control also includes midrange environment backups. • Define standards for test to production turnover and provide these standards to Client for approval. • Perform test to production tasks by use of agreed upon production processes and tools. • Report on production results in a format and at a frequency mutually defined by Client and ATCO I-Tek. • Be responsible for restart/recovery for production jobs. • Maintain Documentation for job scheduling and re-run requirements, and make this information available to Client. • Maintain production job scheduling tables in accordance with the schedules provided by Client. • Provide production batch initiators/queue, validate job requests and re-run instructions, and notify Client of job completion through a mutually defined process. • Provide back up and restore functions. • On-site Client staff will continue to provide ATCO I-Tek staff with adhoc assistance where required at remote sites		Restoration of client data as a result of client error in deletion of data. Client will request data restoration. Fees will be at the Time and Materials Rates. New project requirements will be completed as part of the approved Client SOW.			Included in server rates.

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Software	***Software License Management*** Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement. • Provide Software technology planning. • Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate. • Investigate, evaluate, install and implement any required non-standard products when required by a Client. • Maintain all software in production using ATCO I-Tek corporate standard processes. • Disaster recovery planning for all supported software platforms. ***Software audit compliance.*** • ATCO I-Tek will manage and be responsible for Third Party software vendors and their respective software • Record • Track • Dispose ***Software Upgrades*** • Research upgrades or replacement products • Evaluate • Test to confirm functionality. • Plan implementation validate software licensing • Build package or evaluate technical capabilities • Install or upgrade		Licenses acquired by an ATCO business unit are not managed by ATCO I-Tek.		Compliance with change management process.	Business application service fees for all specialized hardware and software services. Software acquisition outside the specified bandwidth will be Specified Expenses and Time and Materials Rates.

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates

1	Performance Tuning & System Monitoring	***Performance Tuning***
		Performance tuning is making modifications such as changes to operating system software, to the existing network and to system configurations to achieve maximum System responsiveness and throughput.
		This will be done through periodic gathering of performance and capacity data using a variety of tools. The gathering and analysis of this data is performed in various fashions.
		• ATCO I-Tek will keep the System(s), comprised of the hardware and software covered by the Service Level Agreement operating within mutually determined thresholds.
		System Monitoring
		System monitoring consists of monitoring the availability and utilization of System resources within ATCO's Client/server computing environment.
		• Respond to automatic paging associated with predetermined server events and build on existing processes to allow for proactive problem determination.
		• Collect capacity and performance data for the following items on an ad hoc or problem basis:
		  • Disk monitoring
		  • CPU utilization
		  • Uptime analysis
		  • Memory utilization
		• Provide Systems monitoring event notification
		• Resolve System problems as per the problem management and service request process.
		• Have authority over servers thereby establishing account IDs on managed servers
							Business application service fees for all specialized hardware and software services.

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2.15 Server Management & Support - continued

(File, print & database servers; includes mid-range servers)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Operational Recovery	• ATCO I-Tek provides services to recover production processing and data in the event of an outage causing any impact to the production environment or a production application. Operational Recovery is distinct from Disaster Recovery in that the computing facilities are assumed to be largely intact and operational. Data can be recovered up to six weeks previously.	***Mid Range and Local Area Network Servers*** Recovery of a distributed server's data is at a rate of 10 GB per hour. Recovery of individual files (less than 1 GB in size) is within 2 hours. Data recovery is limited to 6 weeks	Client requested file recovery.	ATCO I-Tek will provide information to Clients so that they understand their role in backup procedures at remote sites.	Follow documented backup procedures at remote sites.	Workstation rates (include file and print services) Business application service fees for all specialized hardware and software services

2.16 Network Equipment Management & Support

Manage LAN

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Network and Systems Management	Network and Systems management is the management of the network infrastructure and shared Systems to meet or exceed defined Service Levels. ***Network Service*** The Network Service consists of circuits and equipment to facilitate Client to Client connectivity, local or wide area. • Perform network planning, consisting of network design, capacity planning and technology refresh planning. • Provide proactive, centralized monitoring and configuration management. • Provide problem resolution by following the existing Problem Management process. • Provide network fault isolation, trouble ticket generation and management of the recovery of network-related problems, including interface with carrier and other vendors.	Maintain availability for all monitored devices on a 7 x 24 basis except during Change Windows and back up of disk storage as scheduled. Automated processes will be implemented as available and required.				Network Connection rates.

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2.16 Network Equipment Management & Support – continued

Manage LAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Network and Systems Management – continued	• Manage the relationship with, Third Party vendors of ATCO I-Tek for the acquisition and maintenance of all data telecommunications services and equipment. • Collect and analyze network performance data to evaluate efficiency, measure availability, and utilize as input for network tuning. • Recommend to ATCO, technology upgrades with regard to increases in WAN requirements for improved efficiencies. • Maintain inventory information and Documentation on ATCO owned WAN related equipment in the format and reflecting the information as the parties may mutually agree. • Perform network change requests in accordance and frequency with the existing change request process. • Gather, analyze, and validate entire network traffic and transactions against the current network design. • Confirm and document the network design and capacity requirements and submit to ATCO capacity-planning projections in a format mutually determined by ATCO and ATCO I-Tek. • Provide Telecommunication Engineering services only for those assets managed and operationally controlled by ATCO I-Tek. • In the event that current network hardware and software does not meet the minimum standards required for ATCO I-Tek to perform the network management services described in this document, ATCO will work with ATCO I-Tek to determine the best alternative solution and participate as required in the implementation of this solution.					

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2.16 Network Equipment Management & Support – continued

Manage LAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Network Device Management	Network device management and monitoring is to remotely maintain the configuration of network devices and monitor the operating environment for error conditions. • Provide for the setting of operational parameters, port configurations and management software activities including: • Device chassis configuration • Device segmentation configuration • Device port configuration including port activation/de-activation • Device hardware failure detection and notification • Associate a Network Interface Card (NIC) to a specific port • Identify where errors on the segment are being generated • ATCO I-Tek will execute the capacity management plan on an annual basis over a defined period to be agreed to with ATCO. • ATCO I-Tek will provide prices proposals and justification to ATCO for additional capacity requirements	Automated processes will be implemented as available and required.				Network Connection rates
1	LAN Segment Utilization and Network Utilization	LAN Segment Utilization and Network Utilization is determining the baseline performance and collecting the performance data of the network during a definitive time frame. • Perform comparisons of utilization to baseline. • Monitoring platforms will be upgraded, as required, to enhance service capabilities. This may occur because of advances in software provided by vendor or modifications to existing software developed by vendors or ATCO I-Tek	Automated processes will be implemented as available and required.				Network Connection rates

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2.16 Network Equipment Management & Support – continued

Manage LAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Configure, Install, Move, Remove	• Design and coordinate the installation of physical configuration • Configure / install / de-install specialized network software • Validate that all installed software is properly licensed • Coordinate wiring • Test to confirm functionality	Network equipment includes hubs, bridges, modems and gateway facilities on the ATCO Network, as outlined in this Agreement.	Impact of additional sites implemented will be assessed & priced			Network Connection Time and Materials Rates
1	Support/Repair	• Purchase, receive & install parts or software • Repair hardware					Network Connection rates
1	Performance Tuning	***Network Monitoring*** Network Monitoring keeps track of the availability of networks, LAN segments utilization, and the performance of resources. • Network utilization problems that are identified, will be provided before ATCO is affected. • Respond to end-user detected changes in usage and/or erratic response activity. Users are encouraged to contact the CSC and report any such incidents. • Monitor fluctuations and variances in available capacity. These will be analyzed, diagnosed and corrected (including root cause analysis) as necessary through appropriate priority levels. ***System Management*** System management is the monitoring of network resources to maintain the optimum server environment and provide centralized control of resource configurations. • Measure and record data and provide report information regarding the performance and capacity of the managed Systems, comprised of the hardware and software, as required. • Perform long-term trending of the utilization of key System resources and recommendations for replacement/upgrade of resources	Monitor the network resources and maintain availability for all monitored devices on a 7 x 24 basis except during Change Windows and back up of disk storage as scheduled. Automated processes will be implemented as available and required.				Network Connection rates

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2.16 Network Equipment Management & Support – continued

Manage LAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Performance Tuning - continued	• Regular meetings between ATCO I-Tek and ATCO will be scheduled to review resource utilization and trends. • Assess ATCO's platform environment, including hardware, workstation operating system and network operating system. • Provide an impact study document of a performance simulation containing recommendations for improving the environment's performance, including usage thresholds, performance tuning and configuration changes					
1	Software	***Software License Management*** Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement. • Provide Software technology planning. • Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate. • Investigate, evaluate, install and implement any required non-standard products when required by a Client. • Maintain all software in production using ATCO I-Tek corporate standard processes. • Disaster recovery planning for all supported software platforms.	Automated processes will be implemented as available and required.	Software required outside the base services			Network Connection rates

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2.16 Network Equipment Management & Support – continued

Manage LAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Software - continued	***Software audit compliance.*** • ATCO I-Tek will manage and be responsible for Third Party software vendors and their respective software as outlined in Appendix B (Security Framework Standards) of Schedule A (Service Levels) • Record • Track • Dispose ***Software Upgrades*** • Research upgrades or replacement products • Evaluate • Test to confirm functionality. • Plan implementation to validate software licensing • Build package or evaluate technical capabilities • Install or upgrade					
1	Provide Capacity Planning	• Monitor network capacity • Analyze trends & predict capacity requirements • Report on areas requiring upgrade	Automated processes will be implemented as available and required.				Network Connection rates

Manage WAN

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Configure, Install, Move, Remove	• Design and coordinate the installation of physical configuration • Configure / install / de-install specialized network software • Validate that all installed software is properly licensed • Coordinate wiring • Test to confirm functionality	Network equipment includes routers & circuits on ATCO WAN	Impact of additional sites implemented will be assessed & priced Third Party costs, where applicable			Wide Area Network Service and bill at Time and Materials Rates.
1	Telecommunication Engineering services	• Submit a completed assessment and design recommendations for new requests and recommend cost estimates for the technical design, hardware, software, circuits, labour and organizational impact to ATCO for review and approval.					Time and Materials Rates.

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
		• Analyze current technology trends and changes; analyze new technology to assess its ability to meet present and future design requirements, and work with ATCO to evaluate new business requirements against traffic trends.					

2.16 Network Equipment Management & Support – continued

Manage WAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Telecommunication Engineering services – continued	• ATCO I-Tek's recommendations will conform to appropriate Service Policies and procedures of ATCO's telecommunications standards and take into account ATCO future needs for additional workstation users, centralization of network equipment or peripherals and new applications, and will leverage available facilities (bandwidth, hardware, floor space, etc.) whenever possible.					
1	Support/Repair	• Purchase, receive & install parts or software • Repair hardware					Wide Area Network service rates.
1	Network Optimizing	• Monitor, analyze and adjust to achieve optimal performance of the supported network.	Automated processes will be implemented as available and required.			Review when required	Wide Area Network service rates.
1	Recovery	• WAN recovery					Wide Area Network service rates.

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2.16 Network Equipment Management & Support – continued

Manage WAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Software	***Software License Management*** Software license management is the management of software license agreements that are supplied and installed by ATCO I-Tek pursuant to the Service Level Agreement. • Provide Software technology planning. • Implement ATCO I-Tek corporate standard software distributions and individual products as appropriate. • Investigate, evaluate, install and implement any required non-standard products when required by a Client. • Maintain all software in production using ATCO I-Tek corporate standard processes. • Disaster recovery planning for all supported software platforms. ***Software audit compliance.*** • ATCO I-Tek will manage and be responsible for Third Party software vendors and their respective software as outlined in Appendix B (Security Framework Standards) of Schedule A (Service Levels) • Record • Track • Dispose ***Software Upgrades*** • Research upgrades or replacement products • Evaluate • Test to confirm functionality. • Plan implementation to validate software licensing • Build package or evaluate technical capabilities • Install or upgrade	Automated process will be implemented as available and required.				Wide Area Network service rates. Software outside of base services will be Specified Expenses.

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2.16 Network Equipment Management & Support – continued

Manage WAN - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Provide Capacity Planning	• Manage network capacity. • Monitor network capacity • Analyze trends & predict capacity requirements • Report on areas requiring upgrade	Automated process will be implemented as available and required.				Included in Wide Area Network Rates
2	Development	• Design, plan, test & implement WAN networks for new sites or significant upgrades to existing sites					Time and Materials Rates.

Manage Voice

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Voice Equipment	• Manage voice equipment • Design • Monitor • Maintain environment (wiring, telephone jacks) • Implement • Identify & implement upgrades					Voice Rates
1	Telecommunications services	• Be the single point of contact for telecommunications network installations, moves and adds, fault notification and resolution. • Provide telecommunications service coordination and management of third-party service providers including exchange carriers. • Administer and coordinate the physical and logical configuration of the telecommunications network. • Provide planning, engineering, installation and maintenance support for the telecommunications network. • Provide integration support for new telecommunications network Systems. • Provide reporting for telecommunications network performance.					Voice Rates and applicable Specified Expenses.

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2.16 Network Equipment Management & Support – continued

Manage Voice - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Telecommunications services - continued	• Provide input and advice in the development of design and implementation plans to meet service requirements. • Provide input and advise in the development of a telecommunications architecture technology Service Policy. • Contract with a Third Party for the provision of the physical layer of the voice and data network. • On-site ATCO staff will continue to provide ATCO I-Tek staff with adhoc assistance where required at remote sites.					
1	Voice Tele-communications Service	The Voice Telecommunications service is Voice Premises services, consisting of standard analog and/or digital telephone line services, workstation voice instruments, and Public/Private Voice services. Public/Private Voice services includes: Telecommunication Company provided dial tone through local, 800, tie lines and long distance facilities. ATCO I-Tek will manage and provide these services for the participating Clients. • Serve as the single point-of-contact for ATCO in coordination of Third Party telecommunications network suppliers and telecommunication equipment providers. • Manage ATCO installed voice network equipment consisting of circuits, access equipment, wiring and standard telecommunications lines and equipment covered by the Service Level Agreement. • Perform voice service planning consisting of network design, capacity planning and technology refresh planning. Provide voice usage reports in the frequency, format and reflecting the information as mutually determined by Client and ATCO I-Tek, as currently provided.					Voice Rates

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Manage Voice - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Voice Tele-communications Service - continued	• Manage ATCO contracts for long distance, local exchange, 800# services, tie lines, pager, cellular phones and calling card services • Coordinate and manage the resolution of voice network issues, including equipment issues and interfaces with carriers and other vendors. Provide problem resolution up to the point of determination that the problem is related to particular equipment, forwarding the problem to the appropriate repair/maintenance entity, and serving as a single point of contact during the problem resolution process. • Manage and coordinate through designated maintenance providers the support of Private Branch Exchange ("**PBX**"), tie lines, key System and voice mail service. • Coordinate through designated maintenance providers to perform moves, adds and changes on telecommunications equipment as follows which may include: changing telephones and features, installing new telephone sets and lines, moving telephones, removing and disconnecting telephone sets and lines, adding voice mail boxes, and changing voice mail features. • Manage and coordinate the publication of electronic telephone directories.					

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2.16 Network Equipment Management & Support – continued

Manage Voice - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Moves and Adds	• Provide move and add services to the ATCO network or will coordinate work through a designated maintenance provider. • Coordinate moves and adds service through the designated maintenance provider. • Manage and coordinate the installation, configuration and testing of equipment, related devices and services.					Voice services Time and Materials Rates.
1	Moves and Adds – continued	• Coordinate removal Service for telecommunication equipment, being the physical and logical de-installation and proper disposal or cancellation of telecommunication equipment and services					Voice services Time and Materials Rates.

Manage Video Conference

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)es	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Configure, Install, Move, Remove hardware & Software	• Design & Coordinate Installation of physical configuration • Configure & install/de-install software • Validate that all installed software is properly licensed • Coordinate wiring • Test • Document	Standard video conferencing Equipment (CODEC's, monitors, DUS's, network interface components, microphones, document camera on Video equipment)	Future technology changes to equipment used			Included in video conference rates
1	Manage service agreements with Third Party	• Contact potential suppliers • Develop contracts/agreements • Manage agreements so that they are met	All video conferencing equipment and related networks			Review and audit	Included in video conference rates
1	Problem Management	• Prioritize problems • Assign • Analyze problems • Find root cause • Resolve problems • Post analysis • Document	All video conferencing equipment and networks	Out of scope hardware and software			Included in video conference rates

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2.16 Network Equipment Management & Support – continued

Manage Video Conference - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Support/Repair	• Purchase, receive & install parts or software	All video conferencing hardware and network equipment	Out of scope hardware and software			Included in video conference rates
1	Optimization	• Monitor, analyze, and adjustment configuration.	All video conferencing hardware and network equipment	Out of scope hardware and software			Included in video conference rates
1	Security: Physical	• Provide standards and guidelines for the physical security of all video conferencing equipment.	All video conferencing hardware and network equipment	Out of scope hardware and software. Monitoring, reporting, and control of physical security of equipment is the responsibility of the Clients			Included in video conference rates
1	Security: Logical	• Provide standards and guidelines for the logical security of all video conferencing hardware • Recommend, maintain, and publish Service Policies and procedures on logical security • Provide security and ID administration for the logical network	All video conferencing hardware and network equipment Monitoring, reporting, and control of logical security of video conferencing equipment	Out of scope hardware and software			Included in video conference rates
1	Upgrades	• Research upgrades or replacement for video conferencing equipment • Evaluate, Test, and Implement • Validate licensing • Build package	All video conferencing hardware and network equipment	Out of scope hardware and software			Included in video conference rates
1	License Management	• Record • Track	All video conferencing hardware and network equipment	Out of scope hardware and software			Included in video conference rates
1	Provide Capacity Planning	• Monitor usage. • Analyze trends & predict capacity requirements at sites and MCU.	All video conferencing hardware and network equipment	Out of scope hardware and software			Included in video conference rates

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2.17 Business Solutions and Applications Services

Application Service Provider (ASP)
(Under 40 Person-days Tier 1, Over 40 Person-days Tier 2)

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
	Applications	The Application Service Provider (ASP) offering provided by ATCO I-Tek includes three components: · Application license and annual maintenance fees include application licensing, annual maintenance fees and license management. · Application hosting includes hardware support and maintenance, annual capacity planning, operating system and application code storage, security administration, performance monitoring and operational recovery. · Application support includes database maintenance, applications maintenance and tuning, System administration and application support. Minor application upgrades (point releases for example. 11.z to 11.y) are included in the ASP fees .		Full application upgrades Data storage, archiving, disaster recovery and the infrastructure required to connect to the application are excluded from the ASP offering.			Fixed fee per month
	Application Maintenance Service (AMS)	Provides the Client with a service to fix the business application when it fails to operate or is not operating according to specification as well as maintaining the development and testing environment for the specific application.					Fixed fee per month
	Application Enhancement Service	Provides the Client with a service for adding new business functionality or enhancing existing business functionality of an existing application for the Clients.			· Prepare SOWs · Responsible for the delivery of IT Deliverables defined in the SOW	· Create Request for Service and define busines s requirements · Prepare testing scenarios and test scripts required to perform user acceptance testing	Time and Materials Rates

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
						· Perform the user acceptance testing · Responsible for understanding business impacts, change management and implementation	
	Application Architecture Study & Feasibility Service	Provides the Client with an Architecture Study with the purpose to leverage the data, application and technology assets of the company, taking into consideration the company's business drivers, the future mode of operation, the industry technology and application trends. The Application Architecture Study sService offering includes recommending the application roadmap from that supports the company's business.			· Prepare SOWs · Responsible for the delivery of IT Deliverables defined in the SOW	Provide RFS and business vision, strategy and key requirements	Time and Materials Rates
	Application Development Service	Provide custom build new system or subsystem to meet the Client business needs using the application development methodology, tools and IT project management expertise.			· Prepare SOWs · Responsible for the delivery of IT Deliverables defined in the SOW	· Provide RFS and business requirements · Prepare testing scenarios and test scripts required to perform user acceptance testing · Perform the User Acceptance testing · Responsible for understanding business impacts, change management and implementation	Time and Materials Rates
	Application Integration and Implementation	Provides requirements analysis, fit/gap analysis, configuration, extension,			· Prepare SOWs · Responsible for the	· Provide Request for Service and	Time and Materials Rates

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Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
	Service	integration and implementation of packaged business software to automate Client business functions.			delivery of IT Deliverables defined in the SOW	business requirements · Prepare testing scenarios and test scripts required to perform user acceptance testing · Perform the User Acceptance testing · Responsible for understanding business impacts, change management and implementation	
	Business and Application Solution Consultation Service	Provides consultation services to the Client on areas such as evaluating the feasibility of automating business processes; interpretation of government deregulation rules and regulations to assess the impact to applications, business processes, operations; evaluating end-to-end manual and automated business processes for process improvement					Time and Materials Rates

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2.18 Database Management & Support

Development

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1,2	New databases	• Feasibility study • Gather requirements • Analysis • Functional Design • Create physical data model • Create data dictionary • Develop security requirements/procedures • Provide backup/recovery procedures & products that are in place • Implement in test environment • Test to confirm functionality • Assist with data conversion • Implement in production • Prepare a post implementation review				Provide requirements	Time and Materials Rates.
1	Database products	• Evaluate • Test to confirm functionality • Make configuration changes required • Implement					Time and Materials Rates.

Maintenance & Enhancement

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1,2	Support	• Design database change • Test to confirm functionality • Update existing data models & data dictionaries for database changes • Implement changes to meet business requirements • Provide adequate backup & recovery for all databases • Follow disaster recovery plan procedures • Follow security procedures • Evaluate product upgrades • Plan database upgrades • Implement upgrades					Time and Materials Rates.

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2.18 Database Management & Support

Maintenance & Enhancement - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Capacity Planning	• Manage capacity • Liaise with System owners to improve data quality. • Proactively manage use of DASD, predict growth and request additional DASD as required					Time and Materials Rates
1	Performance tuning on mainframe databases	• Monitor performance • Tune where necessary to maintain agreed to Service Levels. • Implement data reorganization to maximize performance.					Time and Materials Rates

2.19 Data Management

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Data Security	• Manage user access rights and data access rights for both distributed & mainframe environment • Manage security Service Policies and procedures as approved by the ATCO Group		Data management relating to major ATCO reorganizations and Tier I or II projects		Define requirements for data security	Included in all Rates.
1	Data Management	***Data Management for the Enterprise Server*** • ATCO I-Tek provides services to electronically maintain and manage the storage and retrieval of data. • Data management includes HSM data-set deletion standards. The standards are required to help with DASD capacity management and to avoid unneeded costs for increasing data storage capacity. • Data on the enterprise server is managed by applications or Clients and is stored in various files, data sets and databases on the enterprise server. Clients are responsible for the maintenance of their data.	Data base management software tools review, investigated and implement if necessary.	Data management relating to major ATCO Reorganizations and Tier I or II projects.	ATCO I-Tek is responsible for informing Clients of redundant data sets and procedures for the maintenance of the data.	ATCO Clients are responsible to follow the recommended procedures. This will assist in DASD capacity management and to avoid unneeded costs for increasing data storage capacity	Storage Rates.

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2.19 Data Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Data Management - continued	• A batch process can be run that identifies all data sets and files (All other data sets and files including user data sets (prefix U***) are included) that have not been accessed for 12 months or more that summarizes the findings in a report. Data-set owners are responsible for deletion of redundant data sets • Follow all procedures for the administration of data, including user notification, data archives, file deletions and a process to handle data owned by terminated employees • Move data as required due to Client position changes		Unscheduled and specialized reporting requests.			
1	Backup and Restore	***Backup and Restore*** Backup and Restore are functions required to maintain the availability of data. These include the backup of shared data on servers, the storage of that data and the process to restore data once it is lost. The backups can be retrieved and used to recover the computer facility to a point in time, in order to continue business operations and processes. The backups are used in the event of any type of outage for: file recovery; application database recovery; full production recovery; and disaster recovery. • Back up operating system software, application software and application data to tape. Tape backups will be held in offsite storage.		Backup and restore of workstation data. Client requested file restores.	ATCO I-Tek to define backup methodologies / strategies ATCO I-Tek to recommend levels of authentication needed for restores of any file ATCO I-Tek to define process for backup and restores and communicate to Clients. Service Policies and procedures for backup and restores communicated to all users	Client to approve backup methodologies / strategies. Client to approve levels of authentication needed for restores of any file Client personnel to assist in the backup process at remote locations.	Storage Rates.

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2.19 Data Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Backup and Restore - Enterprise Server	There are four types of backups that can be required by an application. Backups are performed for the application, the database, the full volume DASD and the software product used. The Application Coordinator is responsible for providing data retention requirements for their respective applications. ATCO I-Tek will validate that the respective application is recoverable from regular backups.	Weekly backup tapes will be retained for six weeks. In the event of recovery from backup, work with Clients to synchronize databases before normal on-line processing resumes Full enterprise server System backups are taken weekly with incremental backups taken daily. "Full backups" means that the whole storage space (DASD volume) is copied to tape and incremental means that only those files that have changed, since the last backup, are copied to tape. The backup strategy addresses backups for databases, DASD volumes, application files and product software. The goal of the strategies is to minimize the potential for data loss. Production database backups are scheduled daily by the automated production scheduling product. Dual copies are required, one copy for onsite and one copy offsite. The data-set names must conform to Production Job Control Language standards. All development, test, production and application data sets are controlled through the SMS (Storage Management System). All tape data sets must be added to the backup reference file.		ATCO I-Tek to define backup methodologies and strategies.	Client to approve backup methodologies and strategies. Client to verify backup methods, frequency and retention meet business needs.	Storage Rates.

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2.19 Data Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Backup and Restore - Enterprise Server - continued		DB2 backups are kept based on date control for 42 days. DB2 archive log data sets are kept for 42 days. DB2 catalog are kept for 42 days. The full DASD volume backups are run every weekend, scheduled from 21:00 Saturday to 7:30 Sunday. Incremental backups are completed daily. Weekly full DASD volume backups - 6 generations kept (approximately six weeks) daily incremental backups - 42 generations kept (approximately 6 weeks).				

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2.19 Data Management - continued

Tier	Category	Major Scope Items (not all inclusive)	Included in Base Rates	Excluded from Base Rate (Time and Materials Rates apply)	ATCO I-Tek Responsibility	Client Responsibility	Service Rates
1	Back up and restore – Distributed Servers	Backups are scheduled Monday – Friday between 18:00 and 07:00 for each server. There are some exceptions where the backups are scheduled on the weekends. If a file is modified on the server, a backup copy is taken and it becomes the active file; the previous active file becomes inactive. The data retention Service Policy will keep the inactive file for 32 days. If the active file is deleted from the server the data retention Service Policy will keep it for 42 days. A second copy of the backup is kept offsite .	Local Area Network Servers will have weekly full and daily incremental backups taken each Monday - Saturday during the 18:00 – 07:00 window. Backup failures will be rerun the next Business Day after 16:30. Recovery of a distributed file server is performed at a rate of approx. 10 GB per hour. Recovery of individual files (approx. 5 GB per hour) is within two hours if backup is on site; one day if backup is off site.	Recovery of e-mail is not included in the service rate. It is performed on a Time and Materials charge at current Time and Materials Rates. Client requested file restores.		Client to approve backup methodologies and strategies. Client to verify backup methods, frequency and retention meet business needs	File server storage and e-mail storage rates.
1	Backup and Restore - Workstation Systems	To allow all data to be included in the scheduled backup, it must be stored on the network. The backup of data files residing on the workstation is the responsibility of the user.		Workstation systems are not backed up. Backup and restore of workstation systems.		Backup of data files residing on the workstation.	No rates.

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INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule C
Service Measures

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SCHEDULE C - SERVICE MEASURES

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1.0 Introduction

This is Schedule C to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Critical Measures**" means the measurements of certain Services and Service Levels described in Section 8.0 (Critical Measures) of this Schedule.

"**Service Measures**" means the measurements of certain Services and Service Levels described in Section 9.0 (Service Measures) of this Schedule.

2.0 General

2.1 Hours of Availability

The hours of availability are defined in Section 8.0 (Critical Measures).

2.2 Help Desk Hours of Operation

ATCO I-Tek shall provide seven (7) days a week, twenty-four (24) hours a day support for all Services through ATCO I-Tek's single point of contact or through specially designated processes mutually developed with the Client.

2.3 Service Level Measurements

a) Upon Effective Date, ATCO I-Tek agrees to the Service Measures specified in Section 8.0 (Critical Measures) and Section 9.0 (Service Measures).

b) ATCO I-Tek and the Client shall review the Service Measures detailed in Section 8.0 (Critical Measures) and agree upon the Critical Measures, associated Service Credits and Service Measures annually. The Service Levels detailed in Section 8.0 (Critical Measures) and 9.0 (Service Measures) will apply commencing within the first 60 days of the signing of this Master Agreement, unless additional data supports a Change to this Section and is agreed to by the Client.

c) ATCO I-Tek and the Client may propose new, revised or improved Service Level measurements or Service Level targets at any time during the Term and will utilize the following process:

1) The authorized ATCO I-Tek and Client Representatives will agree on and approve the change.

2) The applicable ATCO I-Tek Designated Manager and the Client Designated Manager will be made aware of the Change.

d) Service Level reporting will be on a monthly basis and will include exception-based reporting.

e) The Service Levels will be measured by the average per month.

f) ATCO I-Tek will work with the Client to determine methods of reporting Service Levels where new reporting is required, measurement tools are not practical or may not accurately reflect business need. These methods will be agreed to and any associated incremental costs approved by the Client prior to proceeding with the implementation.

g) ATCO I-Tek will apply any applicable Service Credits as described in Section 6.0 (Service Credits) as of the Effective Date and as agreed to during the Annual Review period.

h) Regular management review meetings shall be scheduled with the Information Technology Governance Committee to review actual performance against projected performance and to recommend actions to be taken to resolve any performance deficiencies.

i) The Parties anticipate that ATCO I-Tek's provision of Services will improve over the Term based on ATCO I-Tek's knowledge of, and access to, resources and technology, implementation of improved methods and procedures for providing the Services, and efficiencies arising from the use of ATCO I-Tek resources and their accompanying skills.

j) ATCO I-Tek, shall during the Term, investigate methods to improve the systems to the benefit of the Client.

k) ATCO I-Tek, shall not be responsible for failure to meet Service Measures or Service Levels while operating under the ATCO I-Tek Disaster Recovery Plan relating to the Agreement, during Change Windows or Scheduled Outages.

l) Specified Critical Service Measures will be subject to the application of Service Credits, as described in Section 6.0 (Service Credits) of this Schedule.

m) Changes to business and Service Level requirements during the Term may result in a revision to Service Categories and Service Levels to improve Services being delivered. A formal review and re-establishment of the Service Levels will be undertaken annually.

n) Should ATCO I-Tek fail to meet Service Levels, an action plan will be developed to address the situation. This action plan will be presented to the Client for review and discussion within 10 days of failure.

o) Target Service Levels are the Service Levels required by the Client.

p) Requests that do not follow standard processes are not subject to Service Levels.

q) For the purposes of this Schedule, availability is based on the required level of support as measured on the basis of the average in a month, and will be calculated as follows:

$$\frac{(SH \times ASDM) - UO}{SH \times ASDM} \times 100 = X\% \text{ availability}$$

Where:

"**SH**" means Supported Hours per day
"**ASDM**" means Average Supported days per month
"**UO**" means Unscheduled/unplanned Outages
"**X**" means the particular percentage availability of the Service Level being measured.

3.0 Time To Respond Service Level Priority Codes

The following table outlines the response Service Level for each priority code:

Priority Code	Description	Time To Respond * (TTR) Business Hours	Time To Respond * (TTR) After Hours
Critical	A problem causing an unscheduled interruption to an application's availability or interrupted Client service. Business impact is or will be severe.	Less than 20 minutes (NOTE 1)	Less than 1 hour (NOTE 1)
High	Problem has disrupted Client service. Client can continue to process, but at great inconvenience. Business impact is high.	Less than 1 Business Hour	NOTE 2
Medium	Client service is degraded. Business impact is moderate to low. Solution required in the short term.	Less than 4 Business Hours	NOTE 2
Low	Current Client service has low or negligible impact. Business impact is low. Solution required in the long term.	Less than 24 Business Hours	NOTE 2

** Time To Respond (TTR) is the elapsed time between when the problem is detected (by a caller or automated alert) and when work begins on the trouble ticket issued.*

NOTE 1: For all critical problems work on the problem will be continuous regardless of time of day, or day of week, until a complete or interim resolution is completed.

NOTE 2: Problems reported outside Business Hours will be processed as if the call was received at 8:00 of the next Business Day.

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4.0 Time To Respond Service Level for Application Managed Service

The following table outlines the solution Service Level:

Priority Code	Description	Time To Respond * (TTR) Business Hours	Time To Respond * (TTR) After Hours
Critical	Applications where a problem causing an unscheduled interruption to an application's availability or interrupted Client service. Business impact is or will be severe.	Less than 1 hour	Less than 2 hours
Non-Critical	Applications where Business impact is not severe	Less than 8 Business Hours	Less than 8 Business Hours

5.0 Time To Solution Service Level For Priority Codes

The following table outlines the solution Service Level for each priority code:

Priority Code	Description	Time To Solution * (TTS) Business Hours	Time To Solution * (TTS) After Hours
Critical	Complete or interim resolution/action plan provided.	Less than 2 hours	Less than 4 hours
High	Complete or interim resolution/action plan provided.	Less than 4 Business Hours	NOTE 1
Medium	Complete or interim resolution/action plan provided.	As Scheduled Within 1 month	NOTE 1
Low	Complete or interim resolution/action plan provided.	As Scheduled Within 3 months	NOTE 1

** Time To Solution (TTS) is the elapsed time between when the problem is detected (by a caller or automated alert) and when an interim solution, a resolution or action plan is provided.*

NOTE 1: Problems reported outside Business Hours will be processed as if the call was received at 8:00 of the next Business Day.

Measurement Assumptions

For measurement purposes the following assumptions have been used:

1. Availability Service Levels and Service Measures exclude the impact of force majeure and events beyond the control of ATCO I-Tek which affect availability.

2. For remote locations, the above times exclude travel and shipping time, where applicable.

6.0 Service Credits

6.1 Critical Measures

ATCO I-Tek and the Client have agreed that there will be Critical Measures. These measures will reflect those Services that impact the Client service and business operations.

During the Term, ATCO I-Tek will track, measure and report against these metrics and identify corrective action where deviations have been reported.

6.2 Service Measures and Service Credits

a. Critical Measures identified in Section 8.0 (Critical Measures) of this Schedule will be subject to Service Credits.

b. Should ATCO I-Tek fail to meet the minimum Service Level for a Critical Measure for one (1) month, the impacted Client will be entitled to a Service Credit as defined in Section 6.3 (Calculation of Service Credits). The Service Credit will be applied to the Client's next monthly invoice. ATCO I-Tek will not have the right to earn back the Service Credit applied as a result of missing the minimum Service Level for that service for that incident.

c. Should ATCO I-Tek fail to meet the target Service Level for a Critical Measure for three (3) consecutive months, the impacted Client will be entitled to a Service Credit as defined in Section 6.3 (Calculation of Service Credits). The Service Credit will be applied to the Client's next monthly invoice. ATCO I-Tek has the right to earn back the Service Credit by meeting the target Service Level for the next six (6) consecutive months. Failure to meet the previously missed target Service Level for the next six (6) consecutive months will result in ATCO I-Tek losing the earn back potential on the specific Service Credit.

d. Failure to meet a target Service Level within the Critical Measures will be counted as one incident towards a Service Credit. As three consecutive incidents are required to invoke a Service Credit, in no event can that same incident be used in the measurement more than once.

e. In the event that more than one Critical Measure Service Level is not met due to the same cause of failure then only the most severe Service Credit will apply.

f. Service Measures exclude the impact of force majeure and events beyond the control or influence of ATCO I-Tek which affect availability.

g. Should a new Service Level or Service Measure be added, the first three (3) months will constitute an acceptance period and minimum and target Service Levels will not apply.

6.3 Calculation of Service Credits

a. A Service Credit is the amount that will be credited by ATCO I-Tek to the impacted Client on their next monthly invoice should ATCO I-Tek fail to meet a minimum Service Level or target Service Level as outlined in 6.2.

b. The maximum total amount of Service Credit(s) payable by ATCO I-Tek in relation to the total Critical Measures in any one month shall initially be 6% of the summation of the monthly invoice amount less fees related to project labour, Specified Expenses, and service requests. (the "at risk" pool).

c. The "at risk" pool will be allocated across the Critical Measures as requested by the Client. The Client can request changes to the allocation of the "at risk" pool during the Annual Review process. In no event will the cumulative percentage allocation exceed more than 110% of the "at risk" pool. In the event of failures to achieve multiple Critical Measures in connection with a single incident, only one Service Credit, that being the highest or most severe will apply. The "at risk" pool will increase over the Term as follows:

   Year 1 – 6%
   Year 2 – 8%
   Year 3 through Year 6 – 10%

d. In the event of a missed Critical Measure, the Service Credit calculation will apply the allocated percentage for the missed Critical Measure as specified in Section 8.0 (Critical Measures), multiplied by the summation of the last impacted monthly invoice amount excluding project labour, service requests and specified expenses. The resulting Service Credit will be applied to the impacted Client's next monthly invoice.

7.0 Service Level Reporting

7.1 Tier 1 Service Level Reporting

Clients will continue to receive current reports, and new reporting requirements will be dealt with during the annual review of Schedule A (Service Levels). New reporting requirements will be developed to coincide with finalized Service Level measurements as requested and approved by the Client.

7.2 Tier 2 and 3 Service Level Reporting

Service Level reporting for Tier 2 Services will be developed jointly with the Client for inclusion in Schedule A (Service Levels). Tier 2 and 3 Service Levels and reporting requirements will be created in the respective Tiered proposals which are approved by Client and these Service Levels will be implemented into Schedule A (Service Levels) on an annual basis.

8.0 Critical Measures

SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Electric: Oracle Financials	Availability based on Business Days and Business Hours	95% average per month.	99.4% average per month.	1.1%	Help Desk Critical	PR
ATCO Electric: LPSS (Load Settlement)	Availability based on Business Days and Business Hours	95% average per month.	99% average per month	1.1%	Help Desk Critical	PR
ATCO Electric: Mainframe Availability	DB2 Database Availability	97.5%	99.9% 0.72 hrs/per month average	1.1%	Monitoring Tool	PR
ATCO Electric: Mainframe Availability	Operating System Availability	97.5%	99.9% 0.72 hrs/per month average	1.1%	Monitoring Tool	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Electric: ATCO Campus LAN Availability Available on a continuous 24 hours per day 7 days per week basis Prime: 8:00 to 19:00 Mon to Fri Non Prime: 19:00 to 8:00 Mon to Fri Block Times: Sunday 7:00 to 24:00 Other Maintenance Upon Request with 5 Business Days notification. Emergency maintenance may be performed outside the above Block Times, based on prior written notification, where appropriate	Includes hubs and switches. Each floor within the ATCO Campuses is separate LANs. Measurement is aggregate average across all LANS	97.5%	99% 7.2 hrs/per month average prime and non-prime	1.1%	Monitoring Tool/Network Services & Help Desk	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Electric: HELP DESK Availability/Client Support On-Site support (Monday to Friday 8:00 until 17:00); Prime: 8:00 – 17:00 Mon to Fri Non-prime: 17:00 – 8:00	ATCO I-Tek support is twenty-four hours a day, seven days a week to respond to Client calls	95%	98% 4.8 hrs/per month	1.1%	Help Desk	PR
ATCO Gas: Oracle Financials	Availability based on Business Days and Business Hours	95% average per month.	99.4% average per month.	1.1%	Help Desk Critical	PR
ATCO Gas: Work Management (Ventyx)	Availability of the application. Excludes telecommunication network and user device	95% average per month.	98.5% average per month. (3.6 hours/ month average for all workstations.)	1.1%	Help Desk Critical	PR
ATCO Gas: Mainframe Availability	DB2 Database Availability	97.5%	99.9% 0.72 hrs/per month average	1.1%	Monitoring Tool	PR
ATCO Gas: Mainframe Availability	Operating System Availability	97.5%	99.9% 0.72 hrs/per month average	1.1%	Monitoring Tool	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Gas: ATCO Campus LAN Availability Available on a continuous 24 hours per day 7 days per week basis Prime: 7:00 to 19:00 to Mon to Fri Non Prime: 19:00 to 7:00 Mon to Fri Block Times: Sunday 7:00 to 24:00 Other Maintenance Upon Request with 5 Business Days notification. Emergency maintenance may be performed outside the above Block Times, based on prior written notification, where appropriate	Includes hubs and switches. Each floor within the ATCO Campuses is separate LANs. Measurement is aggregate average across all LANS	97.5%	99% 7.2 hrs/per month average prime and non-prime	1.1%	Monitoring Tool/Network Services & Help Desk	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Gas: HELP DESK Availability/Client Support On-Site support (Monday to Friday 8:00 until 17:00); Prime: 8:00 – 17:00 Mon to Fri Non-prime: 17:00 – 8:00	ATCO I-Tek support is twenty-four hours a day, seven days a week to respond to Client calls	95%	98% 4.8 hrs/per month	1.1%	Help Desk	PR
ATCO Pipelines: Oracle Financials	Availability based on Business Days and Business Hours	95% average per month.	99.4% average per month.	1.1%	Help Desk Critical	PR
ATCO Pipelines: SCADA System network connectivity	Between ATCO Centre Edmonton and PCC Edmonton only. Corporate network connectivity and availability only. Excludes Telecommunication carrier component	97% average per month	99% average per month. (7.2 hours/ month unavailability	1.1%	Help Desk Critical	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Pipelines: ATCO Campus LAN Availability Available on a continuous 24 hours per day 7 days per week basis Prime: 8:00 to 19:00 Mon to Fri Non Prime: 19:00 to 8:00 Mon to Fri Block Times: Sunday 7:00 to 24:00 Other Maintenance Upon Request with 5 Business Days notification. Emergency maintenance may be performed outside the above Block Times, based on prior written notification, where appropriate	Includes hubs and switches. Each floor within the ATCO Campuses is separate LANs. Measurement is aggregate average across all LANS	97.5%	99% 7.2 hrs/per month average prime and non-prime	1.1%	Monitoring Tool/Network Services & Help Desk	PR

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SERVICE	NOTES/RULES	MINIMUM SERVICE LEVEL	TARGET SERVICE LEVEL	Allocation Percentage of the "at risk" pool	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
ATCO Pipelines: HELP DESK Availability/Client Support On-Site support (Monday to Friday 8:00 until 17:00); Prime: 8:00 – 17:00 Mon to Fri Non-prime: 17:00 – 8:00	ATCO I-Tek support is twenty-four hours a day, seven days a week to respond to Client calls	95%	98% 4.8 hrs/per month	1.1%	Help Desk	PR
ATCO Pipelines: MARS	Availability based on Business Days and Business Hours	95% average per month	98.5 average per month	1.1%	Help Desk Critical	PR
ATCO Pipelines: STAR	Availability based on Business Days and Business Hours	95% average per month	98.5 average per month	1.1%	Help Desk Critical	PR

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9.0 Service Measures

9.1 Mainframe Availability And Response

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
IMS Applications Response (End of Life)	Average response as determined by current measurement capabilities and current transaction profile	0.25 Sec	Monitoring Tool	PR
ADABAS Applications Response (End of Life)		0.25 Sec		
CICS Applications Response (Includes DB2 elapsed time)		0.75 Sec		

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9.2 Server and Midrange Availability

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Operating System Availability As described for database and application availability below.	Includes Database, Midrange, Mail Exchange and File/Print Servers Excludes LAN/WAN Availability Average by Locations	99% 7.2 hrs/per month average	Help Desk	R
General Database Availability 24 hours a day, 7 days a week (7x24) Prime: 7:00 to 19:00 Mon to Fri Non Prime: 19:00 to 7:00 Mon to Fri Block Time: Sunday 7:00 to 24:00 Other Maintenance Upon Request, with 5 Business Days notification	Includes Database, Midrange, Mail Exchange and File/Print Servers Excludes LAN/WAN Availability Includes Remote Sites Average by Locations	99% 7.2 hrs/per month average	Help Desk	R
General Application Availability: 24 hours a day, 7 days a week (7x24) Prime: 7:00 to 19:00 Mon to Fri Non Prime: 19:00 to 7:00 Mon to Fri Block Time: Sunday 7:00 to 24:00 Other Maintenance Upon Request, with 5 Business Days notification	Includes Database, Midrange, Mail Exchange and File/Print Servers Excludes LAN/WAN Availability Average by Locations Includes Remote Sites	99% 7.2 hrs/per month average	Help Desk	R

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9.3 Wan/Lan Availability And Response

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
WAN Availability LAN servers are available 24 hours a day, 7 days a week (7x24) Prime: 7:00 to 19:00 Mon to Fri Non Prime: 19:00 to 7:00 Mon to Fri Block Time: Sunday 7:00 to24:00 Other Maintenance Upon Request, with 5 Business Days notification. Emergency maintenance may be performed outside the above Block Times, based on prior written notification	Includes routers, modems, DSU/CSU, and circuits at networked location. Measurement is aggregate average across all network locations. Measurement is aggregate average across all network components.	99% 7.2 hrs/per month average prime and non-prime	Network Services/Help Desk	R
Firewall (FW) / Intrusion Detection (IDS) Availability available on a continuous 24 hours per day 7 days per week basis Prime: 7:00 to 19:00 Mon to Fri Non Prime: 19:00 to 7:00 Mon to Fri Block Times: Sunday 7:00 to 24:00 Other Maintenance Upon Request, with 5 Business Days notification. Emergency maintenance may be performed outside the above Block Times, based on prior written notification, where appropriate	Includes Firewall and Intrusion Detection devices Measurement is aggregate average across all devices.	99% 7.2 hrs/per month average prime and non-prime	Monitoring Tool/Network Services & Help Desk	R

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SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
WAN Response **LAN Response**	Includes front end processors and routers. Response time definition: Based on network latency which is the average delay time from remote routers to local campus interface route. Measurement is aggregate average across all remote sites. Average delay time for LAN based campus Ethernet devices.	2.9 Secs/Average	Network Services/Help Desk	R

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9.4 Enterprise Print Availability

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Printing Availability Edmonton: Sunday – Friday 22:00 - 24:00 Monday – Friday 00:00 - 16:30		99% of all print volume/month for all applications as per defined Schedule.	Print Services/Help Desk	R

9.5 Enterprise Voice Availability

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Voice Telephone Service Response	Average for in and out bound calls	99%	Network Services/ Help Desk	R
Availability	Defined as the Uptime for the PBX	99%; 7.2 hours/month prime and non-prime	Monitoring tools	
Adds, Moves & Changes	Defined as planned changes to the System	7 Business Days		

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9.6 Support Service Availability & Response – Help Desk

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
HELP DESK **Telephone Response** Prime Only Standby-On Call (Non-Prime)	Response Target is based on a base of 200 calls per day at a typical rate	80% of calls will be answered within 30 seconds and; the Average Speed of Answer (ASA) under 30 seconds	Help Desk	R
First Time Call Resolution	% of calls resolved at first contact Assumes current pattern of problem categories per month	60%	Help Desk	R
Help Desk Call Backs	Random survey of Clients who have reported and logged trouble tickets to confirm satisfaction level was met	20% of all calls will be verified	Help Desk	S/R

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9.7 Support Service Availability & Response – Workstation

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Problem Resolution	Second Level call back from time page is received. Remotes exclude travel and shipping time	See Section 3.0 and 5.0 in this Schedule	Help Desk	R

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9.8 Desktop Hardware and Software – installs/moves/changes

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Desktop hardware and software installs/moves/changes	Includes installation and removal managed on a project basis. Quantities of more than 5 are considered a project. Equipment is leased to clients for various term durations, dependant on equipment type. As part of the lease agreement, ATCO I-Tek will refresh the standard leased device, with a new standard device, within the calendar year that the lease expires. Any costs associated with client added peripherals or upgrades are not included in the lease prices. Within the first 60 days of each calendar year, ATCO I-Tek will provide the client with a summary of the equipment that will be eligible for a refresh. ATCO I-Tek will develop a schedule to complete the refresh during the calendar year. ATCO I-Tek will work with the clients and attempt to schedule refreshes to meet any client business requirements. The Client will be notified of any refreshes that are not completed in the scheduled year.	By Plan Schedule Includes Campus and Non-Campus By Mutually Agreed Date Quarterly plan	Service Requests/Help Desk	R R R

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9.9 Desktop Hardware And Software Changes – install/upgrade Software

SERVICE	NOTES/RULES	TARGET	HOW MEASURED/ Formula	TYPE Priority Report (PR) Report(R) Survey (S)
Install/Upgrade Software Packages Edmonton/Calgary Campus Standard (standard desktop package or business packages required by the business)	Packages on ATCO 'supported list' are standard.	As per agreed time frame	Systems Development/ Help Desk	R
Edmonton/Calgary Campus Non-standard	Non-standard will be a critical service request if business-critical applications are affected	As per agreed time frame		
Non-Campus (remote)	Service levels do not apply to workstations with unauthorized software loaded onto them.	As per agreed time frame Excludes power outages and microwave outages		

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INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule D
Pricing

SCHEDULE D - PRICE SCHEDULE

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1 GENERAL PROVISIONS

This is Schedule D to the Information Technology Master Services Agrement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**COLA**" means cost of labour adjustment.

1.2 Inflation

All prices are quoted in Canadian dollars and are subject to annual price adjustments as set out in section 8.3 (Price Adjustments) of the Agreement.

1.3 Early Return of Equipment

Leased equipment may be returned with three months written notice subject to:

- Return of specialty or non-standard equipment, ordered at the request of the Client, will be subject to a charge equal to the present value of all remaining lease payments for the subject device.
- Specific conditions for a particular service offering will take precedence over this clause.
- Section 1.4 "Bandwidth Pricing"
- The requirement for three months written notice may be waived on a case by case basis by ATCO I-Tek at its' Discretion, where the client allows ATCO I-Tek to manage any returns to fit into ATCO I-Tek's workload and refresh program.

1.4 Bandwidth Pricing

Bandwidth Pricing is applicable to services provided for under the IT Master Services Agreement for the ATCO Utilities. Prices quoted relate to the volumes specified in Section 18. Consumption outside a 15% bandwidth on either side of the base category volume (annual) totals will be cause for a review by Client and ATCO I-Tek to determine if there are any impacts to the fees.

2 SPECIFIED EXPENSE

2.1 Specified Expense - General Provisions

- The Client shall be responsible for payment of certain charges described as a "Specified Expense" on any Schedule ("Specified Expense"). Any expenses paid

by ATCO I-Tek, as requested or directed by the Client, shall be billed at the actual Third Party cost.

3 EXPRESS REQUEST SERVICE

3.1 General Provisions

The Express Service Request allows the Client to expedite a standard service request to be fulfilled before other requests in the standard service request queue. Client service requests are generally fulfilled in the order in which they are received and are referred to as "standard requests". Express service requests take priority over standard requests. Should a third party Service or Equipment provider, required to fulfill the request, prevent the request from being expedited, the Client will be notified.

3.1.1 Products or services provided within the fee

The following are included in the price:

- Placing priority of Express Service requests over standard service requests

3.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The applicable service being expedited

4 APPLICATION SERVICE PROVIDER SERVICE (ASP)

4.1 ASP Service – ATCO Enterprise Applications

ATCO I-Tek's Application Service Provider (ASP) offering for the ATCO Enterprise Applications is split into three components: application licensing, application hosting and support, and Disaster Recovery.

4.1.1 Licensing

Access to the Enterprise Applications are done on a per module basis. Licensing fees and billing metrics are dependant on the type of module. Common metrics include per application user, per employee, per report, or per line item. Licensing for the core modules also depend on whether the user requires "update", or "read-only" access. Licensing terms and conditions will be handled through the Statement of Work process as defined by the Client to meet their business needs.

4.1.2 Application Hosting, Support and Disaster Recovery Services

Scope of services and associated fees are dependant on the number of modules in use, number of named users and configuration of the system including interfaces and

extensions. Scope of services and associated fees will be handled through the Statement of Work process. Disaster Recovery is specific to each application as defined and authorized by the Client.

5 DISTRIBUTED SERVER AND APPLICATION MANAGED SERVICE

5.1 Distributed Server service

Distributed Server service provides the technical infrastructure for clients to run their business specific applications.

The Distributed Server Hosting component is based on the type of server platform, operating system configuration and server specification required.

The Distributed Server Support component is based on the type of server platform, operating system configuration, hours of support required, and level of application complexity.

5.1.1 Distributed Server Hosting

The following tables outline the Distributed Server Hosting options supported by ATCO I-Tek. Hosting fees vary by tier and are segmented by hardware platform. Pricing information is in the fee schedule.

Distributed Server Hosting – Wintel Hardware		
Tier	Server Operating System Configuration	Tier Specifications
Tier 1	Shared	Up to 1 Core & 1GB RAM
Tier 2	Shared	Up to 1 Core & 2GB RAM
Tier 3	Dedicated	Up to 2 Core & 4GB RAM
Tier 4	Dedicated	1 CPU (4 Core) & 8GB RAM
Tier 5	Dedicated	2 CPU (8 Core) & 16GB RAM

Distributed Server Hosting – Unix Hardware		
Tier	Server Operating System Configuration	Tier Specifications
Tier 1	Shared	Up to 1 Core & 2GB RAM
Tier 2	Shared	Up to 1 Core & 4GB RAM
Tier 3	Shared or Dedicated	Up to 2 Core & 6GB RAM
Tier 4	Dedicated	1 CPU (4 Core) & 16GB RAM
Tier 5	Dedicated	2 CPU (8 Core) & 32GB RAM

5.1.1.1 Products or services provided within the fee

The following are included in the price:

- Server hardware
- Server operating system
- Enterprise level server management software:
  - Monitoring and event management
  - Systems management and automation
  - Security monitoring and management
  - Automated server backup management
- Server hardware and software maintenance
- Premier level vendor support
- Server software data storage and backup
- Server installation
- Server network connectivity
- Data Centre facilities and maintenance

5.1.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Increases in server capacity or performance requirements
- Non-standard server or server software installation
- Non-standard server software licensing and maintenance fees
- Additional software licensing and maintenance fees that may be required for an application
- Application data storage and backup
- Client site specific network connectivity
- Decommissioning of the distributed application
- Disaster Recovery and Business Continuity
- Application monitoring and automation software

5.1.2 Distributed Server Support

The following table outlines the various Distributed Server Support options supported by ATCO I-Tek. Support fees vary by level and are segmented by hardware platform. Pricing information is in the fee schedule.

Distributed Server Support			
Support Level	Server Operating System Configuration	Server Support Coverage	Application Complexity
Bronze	Shared	5x8	Low
Silver	Dedicated	5x8	Low
Gold	Dedicated	7x24	Medium
Platinum	Dedicated	7x24	High

5.1.2.1 Products or services provided within the fee

The following are included in the price:

- Server monitoring and capacity planning
- Server and server software patch management
- Server and server software break/fix maintenance
- Server event troubleshooting and resolution
- Hardware lifecycle management
- Server software lifecycle management
- Server and server software operational recovery

5.1.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Support of non-standard hardware or server software
- Server configuration changes or upgrades
- Application monitoring and automation

5.1.3 Managed Database Licensing

Managed Database Licensing service provides the necessary software for clients to run the database layer of their application. ATCO I-Tek offers shared licensing for applications which run in a shared environment and dedicated licensing for stand alone

environments. Shared database licensing is based on the Distributed Server Hosting tier required for the application and the type of database technology needed. Dedicated database licensing applies to stand alone environments and is offered on both a Named User and CPU basis.

The following tables outline the various options supported by ATCO I-Tek.

Shared Database Licensing			
Distributed Server Hosting Tier	Oracle Standard Available	Oracle Enterprise Available	Microsoft SQL Standard Available
Tier 1	Yes	Yes	N/A
Tier 2	Yes	Yes	Yes
Tier 3	Yes	Yes	Yes
Platform Required	Unix	Unix	Wintel

Dedicated Database Licensing		
Database Technology	Licensing Available	Licensing Notes
Oracle Standard	Named User & Oracle CPU	Named User: Minimum 10 users per Oracle CPU
Oracle Enterprise	Named User & Oracle CPU	Named User: Minimum 25 users per Oracle CPU
Microsoft SQL Standard	SQL CPU	None

5.1.3.1 Products or services provided within the fee

The following are included in the price:

- Database license and maintenance fees
- Ongoing license tracking by user and server
- Ongoing management to maintain software license compliance
- Audit and security vendor compliance reviews
- Ongoing vendor management

5.1.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Additional license and maintenance fees required for an application

5.2 Application Managed service

The Application Managed service (AMS) provides ongoing application maintenance support to allow business applications to function. This involves both preventative and corrective maintenance which provides application reliability and availability.

5.2.1 Products or services provided within the fee

The following are included in the price:

- Running of applications and scheduled jobs in the production environment
- Fixing of production problems or failure for daily operations and regular scheduled batch jobs
- Monitoring hardware, application and database performance
- Maintaining application testing and development environments used for performing the application maintenance functions
- Analyzing and applying application patches, fixes, and minor release upgrades for vendor business software
- Creating test scenarios for testing patches, fixes, and minor release upgrades
- Creating test data
- Fixing production database problems resulting from daily operations.
- Application operational recovery due to system failure resulting from daily operations
- Cloning or refreshing production data to test or development environments, if required
- Change management and version control of business applications
- Notifying the appropriate parties of abnormal system conditions
- Responding to system generated exception notifications and Client problem tickets
- Maintaining issue logs in collaboration with Client (includes the tracking and management of client issues related to a specific application).
- Coordinating scheduled and unscheduled production elevations
- After office hours standby and maintenance support (if applicable)

5.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are not included in the price:

- Enhancing application to add new functionality or changing the design
- Reconfiguration of application capacity due to abnormal growth in business activity outside of historical trends

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- Performance tuning of application due to abnormal growth in business activity outside of historical trends
- Re-running of production job when errors are caused by the Client or as directed by the Client
- Major upgrade or replacement of vendor software or application support tools
- Application end-user functional support and training (ad-hoc reports or how-to questions)
- Packaging and distribution of workstation updates

5.3 Web Hosting

Web Hosting provides clients with an industry standard Hypertext Transfer Protocol (HTTP) Internet / Intranet web site(s). The Web Hosting service is a specific subset of the Application Hosting fee. In addition to the terms identified for the Application Hosting fee, the following terms will apply.

5.3.1 Products or services provided within the fee

The following are included in the fee:

- Administration and support of the hosted web site
- Hosted on Windows platform
- 200 MB of storage
- Web page creation site access and support
- Support for Active Server Pages (ASP) and server scripting technologies
- Monthly web site statistics report
- Search Index Catalogue

5.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Development & Maintenance of the Web site
- Relational Database Hosting
- Disk space for log files (retention determined by Client)
- Publishing
- Personalization and Membership services
- Registration fee and InterNIC fee
- Security access setup

- Special firewall requirements
- Storage above 200 Mb

5.4 Secure Site Web Hosting

Secure Web Hosting provides clients with a secure Internet web site(s). The Secure Web Hosting service is a subset of the Web Hosting service. In addition to the terms identified for the Web Hosting and Application Hosting fee, an industry security certificate is provided.

5.4.1 Products or services provided within the fee

The following are included in the price:

- Certificate provided by a trusted certificate authority

5.5 File Transfer

File Transfer provide Clients with an industry standard File Transfer Protocol (FTP) option.

5.5.1 Products or services provided within the fee

The following are included in the price:

- Administration and support of the hosted FTP site
- 200 MB of storage
- Unique network address

5.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Site registration fee and InterNIC fee
- Security access setup
- Special firewall requirements

5.6 SharePoint

The SharePoint option provides a website for team collaboration; enabling Clients to share documents, tasks, contacts and calendars. The document collaboration features allow for check in, check out, and document version control. The SharePoint environment is designed for easy and flexible deployment and administration of shared content.

5.6.1 Products or services provided within the fee

The following are included in the price:

- Application license
- Application server hardware
- 200 Mb storage
- Management of the SharePoint application

5.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- SharePoint site setup and configuration
- Development and customization of the site
- Data recovery caused by Client error
- Storage above 200 Mb

6 MAINFRAME SERVICE

6.1 General Provisions

Mainframe Service pricing falls into three categories - processing, storage and printing. Mainframe Central Processing Unit (CPU) rates, storage and print usage are charged for development, maintenance and enhancement projects in addition to the production processing. Charges will apply to Tier I, Tier II, and Tier III Project Services for all development and test environments.

6.1.1 Products or services provided within the fee

The following are included in the price:

- Facility operations, tuning and management
- Production management of batch and online applications
- Job and System operational recovery
- Disaster Recovery planning and annual test
- System performance monitoring, tuning and capacity planning
- Information Security Management of the development, test and production environments

6.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Labour associated with application modifications, enhancements, performance and tuning
- Labour associated with the implementation of new Client technologies
- Third Party licensing and maintenance for end of life applications or specialized Client needs

6.2 Central Processing Unit (CPU) Cycles

6.2.1 Products or services provided within the fee

The following are included in the price:

- CPU hardware acquisition, installation and maintenance
- Mainframe network support
- Security monitoring and control

Mainframe Normalization

New rates will be established by ATCO I-Tek when a new mainframe processor is installed. When a mainframe processor is upgraded, and it is agreed to continue with the rates that were established for that mainframe processor, equivalency factors will be used to determine mainframe rates. Equivalency factors will only be applied for a maximum of two generations of mainframe processor upgrades. New rates will be established prior to each upgrade to eliminate the use of equivalency factors, should there be additional generations beyond the two upgrades.

ATCO I-Tek will collect sample CPU usage data on a weekly basis for purposes of observing average CPU usage by workload and for maintaining a historical CPU performance database. When equivalency factors need to be developed for the first and second generation upgrades, they will be based on these historical CPU performance statistics. The developed equivalency factors will be benchmarked against industry recognized equivalency factors supplied by the manufacturer of the mainframe and an industry accepted authority. Significant deviations will be investigated and explained by ATCO I-Tek. ATCO I-Tek will also review CPU performance statistics and equivalency factors with the Clients at the Annual Review.

Mainframe Overhead

Computer tools are used to capture the CPU minutes of technology platforms used by applications. These CPU minutes are billed to Clients by mainframe application. The tools used to capture the CPU usage of online applications do not capture the overhead CPU minutes of the technology platforms used by any subsystem(s) entered through the online applications. The total mainframe CPU minutes less the total of all the applications CPU minutes is the overhead CPU minutes that need to be allocated to Clients. This is done on the basis of establishing technology platform to total mainframe ratios and using these to apportion the overhead.

CPU time capture ratios will be confirmed monthly. ATCO I-Tek will take monthly samplings of the major applications which are representative of normal business cycle workloads and develop a separate CPU time capture ratio for each technology platform. The sampling details, methodology used to establish the ratios, and the final CPU time capture ratios will be reviewed by ATCO I-Tek and the Clients at the Annual Review.

6.2.2 ADABAS CPU Minutes (End of Life – notification March 2006)

ADABAS CPU Minutes provide for CPU utilization charged in minutes for ADABAS software usage.

In the event that ADABAS application environment cannot be decommissioned by the end of June, 2010 due to Client decisions and not the actions of the ATCO I-Tek, the following charges will apply as incurred: (a) increased software license cost due to a planned upgrade of the mainframe and (b) maintenance costs. See also Appendix A 'Enterprise Server' of Schedule A (Service Levels) of the Agreement.

6.2.2.1 Products or services provided within the fee

The following are included in the price:

- Online application access to ADABAS data base system
- ADABAS infrastructure support including database and programming language, installation and maintenance
- ADABAS system performance and tuning
- Interface to DB2 and IMS databases

6.2.3 Non-IMS/ADABAS Batch CPU Minutes

Non-IMS/ADABAS Batch CPU Minutes provide for DB2 and TSO (Time Sharing Option) CPU utilization charged in minutes for batch environment usage.

6.2.3.1 Products or services provided within the fee

The following are included in the price:

- Batch program execution for DB2 and TSO applications including the application code execution
- Mainframe operating system installation, maintenance and tuning
- IBM Program Product acquisition, installation and maintenance
- ATCO I-Tek standard system software installation, maintenance and support

6.2.4 IMS/ADABAS Batch CPU Minutes (End of life – notification March 2006)

IMS/ADABAS Batch CPU Minutes provide for IMS and ADABAS CPU utilization charged in minutes for batch environment usage.

In the event that IMS application environment cannot be decommissioned by the end of June, 2010 due to Client decisions and not the actions of the ATCO I-Tek, the following charges will apply as incurred: (a) increased software license cost due to a planned upgrade of the mainframe and (b) maintenance costs. See also Appendix A 'Enterprise Server' of Schedule A (Service Levels) of the Agreement.

6.2.4.1 Products or services provided within the fee

The following are included in the price:

- Batch program execution for IMS and ADABAS applications including the application code execution
- Mainframe operating system installation, maintenance and tuning
- IBM Program Product, installation and maintenance
- ATCO I-Tek standard system software, installation, maintenance and support

6.2.5 CICS CPU Minutes

CICS CPU Minutes provide for CPU utilization charged in minutes for CICS software usage.

6.2.5.1 Products or services provided within the fee

The following are included in the price:

- Support for interfaces with terminals, printers, and workstations
- Installation, enhancement, monitoring, tuning of CICS mainframe software

6.2.6 DB2 CPU Minutes

DB2 CPU Minutes provide for online CPU utilization charged in minutes for DB2 software usage. DB2 run in batch mode is billed as Non-IMS/ADABAS Batch CPU Minutes.

6.2.6.1 Products or services provided within the fee

The following are included in the price:

- Online application access to DB2 data base system
- DB2 infrastructure support including database and programming language software acquisition, installation and maintenance
- DB2 system performance and tuning

6.2.7 IMS CPU Minutes (End of life – notification March 2006)

IMS CPU Minutes provide for online CPU utilization charged in minutes for IMS software usage.

In the event that IMS application environment cannot be decommissioned by the end of June, 2010 due to Client decisions and not the actions of the ATCO I-Tek, the following

charges will apply as incurred: (a) increased software license cost due to a planned upgrade of the mainframe and (b) maintenance costs. See also Appendix A 'Enterprise Server' of Schedule A (Service Levels) of the Agreement.

6.2.7.1 Products or services provided within the fee

The following are included in the price:

- Online application access to IMS database system
- IMS infrastructure support including database and programming language, installation and maintenance
- IMS system performance and tuning

6.2.8 Time Sharing Option (TSO) CPU Minutes

TSO CPU Minutes provide for CPU utilization charged in minutes for TSO software usage.

6.2.8.1 Products or services provided within the fee

The following are included in the price:

- Online access to TSO
- Acquisition, installation, performance monitoring and tuning of the supported TSO system and related products

6.2.9 Oracle CPU Minutes

Oracle CPU Minutes provide for CPU utilization charged in minutes for Oracle software usage.

6.2.9.1 Products or services provided within the fee

The following are included in the price:

- Online or batch access to Oracle
- Acquisition, installation, performance monitoring and tuning of the supported Oracle system and related products

6.3 Mainframe Print

Mainframe printing is comprised of the following components: equipment, labour, and the CPU cycles used to create the print and the paper. Standard forms are blank sheets of paper while "Special Forms" are printed on paper of non-standard size or paper that comes from the manufacturer with information pre-printed on the form.

6.3.1 Print Forms - Continuous Form

The Print Forms –Continuous Form provides for paper for mainframe printing on continuous form paper.

6.3.1.1 Products or services provided within the fee

The following are included in the price:

- Blank, continuous, 11 x 8.5 standard paper
- Specified Expense

6.3.2 Print Forms - Cut Sheet

The Print Forms – Cut Sheet provides for paper for mainframe printing on cut sheet paper.

6.3.2.1 Products or services provided within the fee

The following are included in the price:

- All print forms are billed according to the cost of the paper stock to the consuming Client

6.3.3 Print Forms - Special Forms

The Print Forms – Special Forms provides for paper for mainframe printing on special paper as requested by the Client.

6.3.3.1 Products or services provided within the fee

The following are included in the price:

- Special forms which are billed to the consuming Client

6.3.4 Print Pages

Print Pages provides for mainframe printing. This fee is based on per 1000 page unit, but billed on actual number of pages printed.

6.3.4.1 Products or services provided within the fee

The following are included in the price:

- Printing on centralized printers
- Printer software
- Acquisition, installation and maintenance of centralized printers and associated facilities
- Acquisition, installation and maintenance of print related software operating system

6.3.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Non-mainframe associated print
- Paper cost of special forms

6.4 Mainframe Print Configuration

Mainframe Print Configuration provides the configuration of the Mainframe to allow printing to a distributed printer.

6.4.1 Products or services provided within the fee

The following are included in the price:

- Setup of Mainframe printer queues to enable printing to an existing distributed printer.

6.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Printer hardware or support

7 DISASTER RECOVERY SERVICE

7.1 Distributed Infrastructure

This service provides Disaster Recovery for the distributed computing and network infrastructure that is required to support business applications in the event of a disaster.

Distributed Infrastructure Disaster Recovery is based on a Recovery Time Objective (RTO) of 72 hours (determined by the clients as a result of their Business Impact Analysis). The disaster scenarios include the Edmonton and Calgary ATCO main sites. The monthly Disaster Recovery fee is charged per full function User ID.

Services indicating a recovery time objective (RTO) of 0 hours may involve a minimal interruption such as reconnecting to a service or server not impacted by the disaster.

Clients have the ability to access Client and client-server applications if the application and file server components are recovered as part of the distributed infrastructure. Clients will annually validate a list of distributed applications affected by the distributed infrastructure.

7.1.1 Products or services provided within the fee

The following are included in the price:

- Internet Web Access – RTO is 0 hours and the Recovery Point Objective (RPO) is 24 hours
- Electronic Mail (Email) Routing –RTO is 0 hours and the RPO is 24 hours
- Virtual Private Network (VPN) – RTO is 0 hours and the RPO is 24 hours
- Windows Domain Authentication – RTO is 0 hours and the RPO is 24 hours
- Anti-Virus Protection – RTO is 0 hours and the RPO is 24 hours

- Internet & Firewall – RTO is 24 hours and the RPO is 24 hours
- Internet Web Sites – RTO is 24 hours and the RPO is 24 hours
- Intranet Web Sites – RTO is 24 hours and the RPO is 24 hours
- Software Distribution – RTO is 48 hours and the RPO is 24 hours
- Anti-Virus Administration – RTO is 72 hours and the RPO is 24 hours
- Email– RTO is 72 hours and the RPO is 24 hours
- File Servers – RTO is 72 hours and the RPO is 24 hours
- Print Servers – RTO is 72 hours and the RPO is 24 hours
- Infrastructure Applicable to Distributed Applications – RTO is 72 hours and the RPO is 24 hours

7.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Business Continuity Planning for the resumption of client business functions
- Client work recovery areas
- Data on workstations and laptops
- Edmonton and Calgary Private Branch Exchange (PBX)
- AS/400 server recovery
- Incremental labour and travel expense costs
- Disaster Recovery (DR) changes required to support significant architectural changes

7.2 Critical and Essential Applications

Critical and Essential Applications provides Disaster Recovery for the critical and essential business applications in the event of a disaster.

Critical and Essential Applications Disaster Recovery is based on the recovery time objectives (RTO's) determined by the client for each critical and essential business application through their Business Impact Analysis.

The monthly Disaster Recovery fee for each application is dependent on the scope and configuration of the work.

Scope of services and associated fees will be handled through the Statement of Work process.

7.3 Remaining Distributed Applications

The Remaining Distributed Applications provides Disaster Recovery for the remaining business applications in the event of a disaster.

The Remaining Applications Disaster Recovery is based on the business applications that were not identified as critical or essential. Two recovery time objectives (RTO's) were established for this service -- 10 Days and Best Effort. The Clients verified their specific business applications and determined the appropriate recovery time objective for each.

The monthly Disaster Recovery fee for each application is dependent on the scope and configuration of the work.

Scope of services and associated fees will be handled through the Statement of Work process.

8 PROJECT LABOUR SERVICE

8.1 General Provisions

Project labour rates will be invoiced on an hourly basis for the following types of service:

- Software development, maintenance and enhancement project services
- Evaluation, systems implementation and integration services
- Consulting services (under agreed upon proposals) including:
  - IT planning and strategic planning
  - Business re-engineering, project leadership and hardware product consulting
  - Other special Projects

8.1.1 Products or services provided within the fee

The following are included in the price:

- Standard development tools needed to build and maintain System
- Standard development methodology
- Standard development support tools
- Professional development for standard methodology and standard development

8.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Client directed vendor and contract negotiations and management
- Special equipment or enhanced equipment
- Special facilities (test, development etc) or project specific facility enhancements and if required will be billed to the project

- Non-standard or special tools, software or methodologies specific to a project Training, training aids or other professional development for non-standard or special tools, software or methodologies specific to a project
- Travel and living expenses and other disbursements related to the project
- Extraordinary items, and if required will be billed on a project by project basis
- Labour rates other than the standard listed rates may be used in cases where an individual has been secured due to a specialized skill set. The rate for the specialized skill set will be determined on a case by case basis and will be communicated to the Client along with the requirements for this skill set in relation to the project and the Deliverables. A management fee of 10% will be applied to the Third Party rates to allow for Contractor Management, supplies and equipment.
- The ATCO Utilities' commitment is to a minimum of 25,000 Development and/or Enhancement hours per year excluding large project labour. Any under-utilization of hours across the ATCO Utilities will be apportioned to the participating Clients proportionate to their individual annual commitment from their Business Plan.

8.2 Hardware Install Move/Addition/Change

This fee is an hourly labour rate associated with installs, moves, adds or changes of non-standard items as requested by the client.

Some examples of where this fee may be applicable are:

- Labour associated with hardware devices such as plotters
- Labour associated with non-standard network equipment not included in the base services

8.3 Software Support Labour

This fee is an hourly labour rate associated with Client requested software support for above Core applications that are not included within a standard service.

8.4 Travel Expense

This fee is a "Specified Expense" of travel expenses associated with Client requested work that are not included within a standard service.

Examples of where this fee will be applicable are:

- Travel associated with network, voice, or hardware installs, moves, adds or changes in remote sites

9 STORAGE SERVICE

Storage represents a variety of supported options to Clients.

9.1 Long Term Archive - First Month

The Long Term Archive – First Month service provides for the setup and migration costs for the first month of Long Term Archive. This service archives data from a network drive to tape and allows for the Client to determine the data retention period. Upon archival of data to tape, the Client may also request the deletion of data from the network drive.

9.1.1 Products or services provided within the fee

The following are included in the price:

- Setup of archive directory
- Client training
- Scheduling of archival process
- Deletion of archived data from network drive

9.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Recovery of lost data due to Client error
- Retrieval of archived data (billable at Time and Materials)

9.2 Long Term Archive

This service maintains archived data that was created with the Long Term Archive - First Month service, until such time the Client requests the deletion of the archived data.

9.2.1 Products or services provided within the fee

The following are included in the price:

- Management of archived files on storage media
- Maintenance of an offsite copy of the archive for Disaster Recovery purposes

9.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Recovery of lost data due to Client error
- Retrieval of archived data (billable at Time & Materials)

9.3 Distributed Application Storage – Local Disk

The Distributed Application Storage – Local Disk service provides disk that is locally attached to an application server.

9.3.1 Products or services provided within the fee

The following are included in the price:

- Disk that is installed on an application server and available for use by applications running on that server
- Backup and operational recovery of the disk including copies stored both onsite and at an offsite storage location
- Implementation and maintenance of system software required to operate the disk

9.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Disaster Recovery

9.4 Distributed Application Storage – Network Attached Disk

The Distributed Application Storage – Network Attached Disk service provides centrally managed disk that is connected to the network and is available to be used by any network attached application server.

9.4.1 Products or services provided within the fee

The following are included in the price:

- Disk that is accessible to an application server and available for use by applications running on that server
- Backup and operational recovery of the disk including copies stored both onsite and at an offsite storage location
- Implementation and maintenance of system software required to operate the disk

9.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Disaster Recovery

9.5 Oracle Financials Storage – Local Disk

The Oracle Financials storage – Local Disk service provides disk that is locally attached to the Oracle Financials server.

9.5.1 Products or services provided within the fee

The following are included in the price:

- Disk that is installed on the Oracle Financials server and available for use by the Oracle Financials application
- Backup and operational recovery of the disk including copies stored both onsite and at an offsite storage location
- Implementation and maintenance of system software required to operate the disk

9.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Disaster Recovery

9.6 Oracle Financials Storage – Network Attached Disk

The Oracle Financials Storage – Network Attached Disk service provides centrally managed disk that is connected to the network and is available to be used by the Oracle Financials application server.

9.6.1 Products or services provided within the fee

The following are included in the price:

- Disk that is accessible to the Oracle Financials server and available for use by the Oracle Financials application
- Backup and operational recovery of the disk including copies stored both onsite and at an offsite storage location
- Implementation and maintenance of system software required to operate the disk

9.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Disaster Recovery

9.7 Website Storage Disk

The Website Storage Disk service provides centrally managed disk that is connected to the network and is available to be used by any network attached web server. This service describes disk that is used in excess of the 200 MB provided in the Web Hosting fee.

9.7.1 Products or services provided within the fee

The following are included in the price:

- Disk that is accessible to a web server and available for use by web based applications running on that server

- Backup and operational recovery of the disk including copies stored both onsite and at an offsite storage location
- Implementation and maintenance of system software required to operate the disk

9.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Disaster Recovery

9.8 Distributed Archive Tape (*End of life*)

The Distributed Archive Tape service provides an application that allows Clients to move seldom used files to tape.

9.8.1 Products or services provided within the fee

The following are included in the price:

- Provision of user interface to archive
- Training to use the interface applications
- Mainframe tape management
- Backup of the archived files

9.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Enhancements to user interface
- Data recovery in the event of Client error

9.9 Distributed Archive Tape Retrieval *(End of life)*

The Distributed Archive Tape Retrieval service provides Clients with the ability to retrieve files from tape and restore the files to disk.

9.9.1 Products or services provided within the fee

The following are included in the price:

- Provision of user interface to recall archived files

9.9.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Data recovery in the event of Client error

9.10 Mainframe Storage

The Mainframe Storage service provides a device onto which data can be placed, held, and later retrieved. "Main storage" refers to the computer's memory, the space used for executing instructions; "DASD" (Direct Access Storage Devices) refers to disks, magnetic tape, and other media for holding data.

9.10.1 General Provisions

9.10.1.1 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Main Storage which is billed within the mainframe CPU rates
- Centralized DASD associated with Distributed Systems
- Optical storage

9.10.2 Mainframe DASD

The Mainframe DASD service provides disk storage or application use in the mainframe environment. This service is measured in Gigabytes of DASD used.

9.10.2.1 Products or services provided within the fee

The following are included in the price:

- Centralized DASD managed by the mainframe
- DASD acquisition, installation, maintenance
- Data storage
- Acquisition, installation, maintenance and tuning of DASD management software
- Backup and recovery, including offsite tape storage and retrieval

9.10.3 Mainframe Tape

Mainframe Tape provides tape storage for Client or application use in the mainframe environment. This service is measured in Gigabytes of tape used.

9.10.3.1 Products or services provided within the fee

The following are included in the price:

- Virtual tape services
- Mainframe managed tape
- Mainframe tape and silo acquisition, installation and maintenance
- Data storage and data retrieval to/from mainframe tape

- Tape support software acquisition, installation and maintenance

9.10.4 Tape Hierarchical Storage Management (HSM)

Tape HSM migrates inactive Client data from mainframe disk to tape.

9.10.4.1 Products or services provided within the fee

The following are included in the price:

- Virtual tape services
- Managed tape
- Tape infrastructure, acquisition, installation, maintenance and support
- Data storage and data retrieval to/from tape
- Support of the HSM environment

9.11 File Server Storage

File Server Storage provides storage for data stored on the network file servers. These items can be, but are not limited to, shared drives, personal network drives, and electronic mail. Where a Client has a terminated status, the Client will continue to receive charges for these services until ATCO I-Tek has been notified to either delete/remove the service or move data to another Client. This service is billed per Gigabyte of storage.

9.11.1 Products or services provided within the fee

The following are included in the price:

- Administration and Support of server as outlined in the MSA Schedule B section 2.15

9.11.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Data moves, cleanup, or Archival services
- Data recovery caused by Client error

9.12 Email Storage – 50 Megabytes Additional

The Electronic mail – 50 Megabytes (Mb) Additional provides for increased email data storage on the network email servers.

9.12.1 Products or services provided within the fee

The following are included in the price:

- 50 Mb of storage

- Administration and Support of the server as outlined in the MSA Schedule B section 2.15

9.12.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Email data moves, cleanup, or Archival services
- Data recovery caused by Client error

10 USER CONNECTIVITY SERVICE

User Connectivity represents a variety of services that are provided to or based on a specific User ID.

10.1 User ID

User ID provides the Client with the setup and management of a secure ID and password.

10.1.1 Products or services provided within the fee

The following are included in the price:

- New User ID setup
  - Windows User ID
  - Email Account with 50 MB storage
  - Setup of permission groups to access data
  - Mainframe User ID (if applicable)
  - Oracle User ID (if applicable)
  - Specific Application User ID access (if applicable)
  - Management of approval process for permissions for each User ID
- Disabling of User ID
- Reactivation of User ID
- Deletion of User ID
  - Remove all system access and User ID
  - Provide copy of mailbag and home drive to supervisor
- Maintain and update Data Owner information for all Permission Groups, Public Folders, Oracle Databases and Application access as provided by the client
- Archiving of the request and approvals for Audit tracking for 2 years

- Creating New Folders with Permission Group
- Adding User ID to Permission Groups
- Password resets requested by User ID owner
- Maintain security and controls standards

10.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- E-mail Storage services above the 50 megabytes
- Client requested investigations
- User ID name changes
- Setup and management of public folders and client access profile groups
- Access reviews
- Client requested changes to overall systems security structure and security group permissions

10.2 User ID w/Limited ATCO Domain Usage

The User ID service w/Limited ATCO Domain Usage provide the Client with setup and management of a secured ID and password with limited access to the ATCO Domain.

10.2.1 Products or services provided within the fee

The following are included in the price:

- New User ID setup
  - Windows User ID
  - Setup of permission groups with limited access
  - Management of approval process for permissions for each User ID
- Disabling of User ID
- Reactivation of User ID
- Deletion of User ID
  - Remove all system access and User ID
- Maintain and update Data Owner information for applicable Permission Groups
- Archiving of the request and approvals for Audit tracking for 2 years
- Password resets requested by User ID owner
- Maintain security and controls standards

10.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Email Account
- Personal network data drive (M: drive)
- Mainframe User ID
- Oracle User ID
- Specific Application User ID access
- Client requested investigations
- User ID name changes

10.3 Confidential Request

Clients have the ability to request that their request for service(s) be managed confidentially by ATCO I-Tek. ATCO I-Tek Support Groups will manage the request accordingly to maintain the confidentiality of the Client request(s).

10.3.1 Products or services provided within the fee

The following are included in the price:

- Confidential management of the request for service(s)
- Manual tracking/processing of request for service(s) where appropriate

10.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Applicable standard service fees apply, as related to the specific service request

10.4 Internet Access

Internet Access provides managed access to the World Wide Web ("the Web") and other Web services. All Internet usage is controlled and monitored to provide compliance with ATCO company policies.

10.4.1 Products or services provided within the fee

The following are included in the price:

- Activation of Internet access on the User ID
- Configuration of Internet Explorer to access the Internet through proxy servers

- Support of standard Internet protocols: HTTP, HTTPS (Hyper Transfer Protocol Secure) and FTP
- Content filtering and usage monitoring
- Protection of Client's workstation against harmful Internet content according to ATCO policy
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access components including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

10.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Direct access to the Internet without using the proxy servers
- Special approved configurations of the firewalls and/or proxy servers will be charged on a Time and Materials basis

10.5 Instant Messaging

Instant Messaging provides real–time text communications, application sharing, whiteboard sharing, and file transfer capability. The Client can use the PC-to-PC communications capabilities to communicate with other subscribers of the service.

BASIC Messenger services/Collaborative services

The following features are included in the Basic service:

Features	Description	Restrictions	Special Equipment
Text	Allows a subscriber to send an instant text message to other internal service subscribers	Messages can be sent to a maximum of 5 subscribers at a time	None
Shared Whiteboard	Two internal subscribers at a time can view and update a 'whiteboard' on their workstation; allows drawing, pasting of images, entering text	Communication is between 2 subscribers at a time	None
Application	A subscriber can allow	Communication is	None

	another internal subscriber to view an application on his/her workstation	between 2 subscribers at a time	

10.5.1 Products or services provided within the fee

The service includes one of the following:

- Software license
- Managing vendor supported product updates and security patches
- 30 days of audit logs

10.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Training
- Software Distribution fee

10.6 Web File service (WFS)

The Web File service (WFS) provides a secure method to transfer files through a web browser. This service allows for transfers with parties external to the ATCO environment.

10.6.1 Products or services provided within the fee

The following are included in the price:

- Administration and support of the Web File service

10.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- All Client accounts are managed by a designated Client owner of the WFS site. This person, or persons, is known as the Delegated Administrator.
- Data stored on the server is assigned to User IDs and billed at the standard File Storage rate

10.7 Web Access Management

Web Access Management provides secure web based user authentication and profile management for Client web based applications that are being accessed by either internal or external users.

10.7.1 Products or services provided within the fee

The following are included in the price:

- Authentication / authorization infrastructure
- Application connectivity to the authentication infrastructure
- Maintenance of the base authentication system
- Client delegated administration

10.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- User connectivity to the application or Internet
- Customization of authentication / Client delegated administration
- Maintenance of application specific data or system configurations
- Application data storage and backup
- Disaster Recovery and business continuity services

10.8 VPN - Remote Client

VPN Remote Client connects mobile employees and telecommuters via the Internet using an Internet Service Provider and a dial-up or high speed (ADSL or cable) connection. The ATCO I-Tek VPN service employs the same high standard of security and management policies that are applied to the ATCO private network.

VPN Remote Client securely connects remote Clients to the ATCO I-Tek network, from their ATCO I-Tek managed workstation, by using VPN Client software installed on the PC, a two-part password combination and the creation of a secure "tunnel" between the PC and the network. Once a VPN tunnel is established, the Client's computer becomes part of the corporate network.

Through the use of authentication, encryption and tunnelling technologies, VPN permits the secure transmission of private data through public networks.

10.8.1 Products or services provided within the fee

The following are included in the price:

- Key fob
- User authentication using a key fob, User ID and PIN
- Authentication and encryption of data transmitted over the Internet

- High level installation documentation and Client software for Windows
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

10.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Internet Service Provider (ISP) setup and associated fees
- Replacement of lost or damaged key fobs
- Installation, operation and maintenance of all hardware and software connected to Client-owned workstations

10.9 Secured Sockets Layer (SSL) Secure Remote Access (SRA)

Secured Sockets Layer (SSL) Secure Remote Access (SRA) allows the Client to securely connect to the corporate applications using any web browser via the public Internet.

When using SSL SRA, a Client has an SSL encrypted session with the SSL device over the Internet. The SSL device decrypts the SSL session and passes the data to the appropriate server.

To use a typical SSL SRA connection, the Client simply browses to the designated web site from any Internet-connected workstation. Upon authenticating to the site, the browser session becomes encrypted with SSL and it begins to communicate with the website via a secure tunnel.

Once connected, depending on the subscription, the Client will have secure remote access to one of the following services:

- Citrix service
- Oracle Financials Self-Service

10.9.1 Products or services provided within the fee

The following are included in the price:

- Key fob
- User authentication using a key fob, User ID and Personal Identification Number (PIN)
- Installation documentation
- Remote access to Citrix service or OFIN (Oracle Financials) Self-Service

- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

10.9.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Internet Service Provider (ISP) setup and associated fees
- Third Party Telecommunications Service Provider fees
- Replacement of lost or damaged key fobs
- Providing assurance of the integrity of data and software on client-owned workstations
- Installation, operation and maintenance of all hardware and software connected to client-owned workstations.

10.10 Citrix Terminal Server

Citrix Terminal Server is a software service that optimizes the secure delivery of Client applications to low bandwidth network locations. The Citrix service provides improved application performance by reducing the amount of data being transferred over the network.

10.10.1 Products or services provided within the fee

The following are included in the price:

- Core office applications (Word, Excel, PowerPoint and Outlook)
- Software license
- Software updates and patch management
- Operational and disaster backup
- Operational recovery

10.10.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Connectivity to ATCO I-Tek network

10.11 Data Recovery

The Data Recovery service provides Clients with the opportunity to request that ATCO I-Tek recover data that the Client has deleted from a network file or email server.

10.11.1 Products or services provided within the fee

The following are included in the price:

- Recovery of Client deleted data from network or file server (billable at Time and Material rates) as requested by the client

10.12 RightFax

RightFax provides an outbound enterprise faxing solution that enables faxing from server and desktop applications.

10.12.1 Products or services provided within the fee

The following are included in the price:

- Administration and Support of the server as outlined in the MSA Schedule B section 2.15
- Administration and support of the RightFax application.

10.12.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Long distances charges

11 NETWORK CONNECTIVITY SERVICE

11.1 Server Load Balancing & Failover

Server Load Balancing & Failover balances Client server sessions amongst a pool of servers and allows for redundancy of mission critical applications and data.

11.1.1 Products or services provided within the fee

The following are included in the price:

- Load balancing and redundancy of services among a pool of physical servers
- Operation and maintenance of the application switch

11.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation, support, and maintenance of the servers
- Moves, adds, and changes to physical servers

11.2 Virtual Private Network (VPN) - Remote Branch

Virtual Private Networking (VPN) Remote Branch connects remote branch offices to the ATCO I-Tek network via the Internet using an Internet Service Provider with high speed (Asymmetric Digital Subscriber Line or Cable) connections. Unlike the laptop based VPN Remote Client, the VPN Remote Branch service utilizes hardware or a "gateway" to perform authentication and encryption rather than Client software on the laptop. The ATCO I-Tek VPN Remote Branch option employs the same high standard of security and management policies that are applied to the ATCO private data network.

In a remote office, "tunnels" are set up between a VPN gateway on the ATCO core network and another VPN gateway on the remote Local Area Network (LAN). Tunnelling allows the use of the Internet, which is a public network, to convey data on behalf of a private network. The VPN gateways provide security services at the network layer, so that the individual workstations and servers do not need to be configured specifically for VPN.

11.2.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over.
- Confidentiality, integrity and authentication of data transmitted over the Internet using encryption technology
- Operation and maintenance of all VPN hardware and software
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

11.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Internet Service Provider (ISP) connection and associated fees
- Installation of the service
- Onsite spare VPN backup hardware

11.3 Virtual Private Network (VPN) – Small Office

The Virtual Private Networking (VPN) Small Office service provides a secure and encrypted connection for small office sites to the ATCO I-Tek network via the Internet. VPN Small Office service is a low-cost alternative to the VPN Remote Branch service. It is suitable for small remote offices with no more than 7 devices, including both workstations and printers.

11.3.1 Products or services provided within the fee

The following are included in the price:

- Network connections for a maximum of seven devices (includes workstations and printers)
- Installation, operation and maintenance of all VPN hardware and software

11.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Selecting and engaging an Internet Service Provider (ISP)
- Guarantee of actual bandwidth, response time, and Internet availability

11.4 Terminal Server

Terminal Server provides for special purpose network devices that connect many different serial devices such as terminals, modems, and computers to Local Area Networks (LAN). Using a terminal server, a Client can access modems, printers and computers that have no built-in network support.

Typical use of terminal servers is to collect data from ATCO Electric substations that are widely spread across the Province. Modem banks are attached to the terminal servers. Specialized applications take control of the modems via the network and collect data from remote substations via dialup connections.

11.4.1 Products or services provided within the fee

The following are included in the price:

- Network connectivity of the Terminal Server
- Customized serial port configuration for various devices and applications
- Operation and maintenance of Terminal Server
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

11.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Support of the serial devices that attach to the Terminal Server
- Installation and configuration of the Terminal Server service

11.5 ADSL Light

Asymmetric Digital Subscriber Line (ADSL) Light service provides a high-speed Wide Area Network (WAN) service connecting a remote office to the core network in Edmonton and Calgary. Typical line speed is 1.5 – 4.0 Mbps downstream and 256 – 900 Kbps upstream. The actual line speed is dependent on several factors including line quality, gauge of wiring, and line distance. This service is only available at locations in Alberta where ADSL is offered by a Telecommunications Service Provider.

ADSL Light service provides a low-cost solution to remote offices where low a volume of traffic is expected. The data transfer is capped at 5 Gigabytes/month. An additional surcharge is applied when the actual usage is over this limit. Service fees consist of two components; the ATCO I-Tek support fee and the Telecommunications Service Provider charge for the underlying data circuit connection from the remote office to the ATCO I-Tek network infrastructure.

11.5.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (1.5 – 4.0 Mbps downstream and 256 – 900 Kbps upstream)
- Installation, operation and maintenance of the networking hardware (ADSL modem and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

11.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the ADSL circuit
- All Third Party Telecommunication Service Provider charges – Specified Expense
- Moves and changes

11.6 ADSL Unlimited

Asymmetric Digital Subscriber Line (ADSL) Unlimited service provides a high-speed Wide Area Network (WAN) service connecting a remote office to the core network in Edmonton and Calgary. Typical line speed is 1.5 – 4.0 Mbps downstream and 256 – 900 Kbps upstream. The actual line speed is dependent on factors such as line quality, gauge of wiring, and line distance. This service is only available at locations in Alberta where ADSL is offered by a Telecommunications Service Provider.

ADSL Unlimited service provides a cost-effective solution to remote offices where high volume of traffic is expected. There is no limit on the amount of data transfer. Service fees consist of two components; the ATCO I-Tek support fee and the Telecommunications Service Provider charge for the underlying data circuit connection from the remote office to the ATCO I-Tek network infrastructure.

11.6.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (1.5 – 4.0 Mbps downstream and 256 – 900 Kbps upstream)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (ADSL modem and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

11.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the ADSL circuit
- All Third Party Telecommunications Service Provider charges – Specified Expense
- Moves and changes

11.7 Network Connectivity

The Network Connectivity service provides local area network connectivity to the ATCO Corporate network for devices that are approved by ATCO I-Tek but not owned and operated by ATCO I-Tek. This includes process control devices.

11.7.1 Products or services provided within the fee

The following are included in the price:

- Local area network switch port (provides the interface point into the ATCO Corporate network)
- All software and hardware
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Any security devices like firewall or intrusion detection equipment
- Any new or additional wide area network equipment required to support the addition of the network connected device to the corporate network
- Cabling from the device to the network connection point

11.8 Network Telecom Fee

The Network Telecom Fee is used to provide a method of charging costs that are not directly attributed to circuits. These are fees typically associated with the installation, repair or maintenance of network services. For non-circuit network-related charges, services could include installation or one-off services. A line item in this service might contain an amalgamation of several charges into one line item.

11.8.1 Products or services provided within the fee

The following are included in the price:

- Setup and management

11.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- This is a billing mechanism and therefore any associated elements are excluded
- Any investigations into charges

11.9 Blackberry

The Blackberry option provides for an encrypted, wireless, real-time calendar and email synchronization with ATCO's business email environment.

ATCO I-Tek provides full support for product capability including:

- Email
- Voice support
- Calendaring
- Internet access
- File attachment capability

11.9.1 Products or services provided within the fee

The following are included in the price:

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- Infrastructure to facilitate e-mail communication with the Blackberry device
- Blackberry software licenses

11.9.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Blackberry device
- Procurement and asset management of Blackberry devices if requested
- Device sparing
- Monthly voice and data costs from Third Party Service Provider
- Support of Third Party wireless network Email accounts
- Vendor management

11.10 Shared Blackberry

The Shared Blackberry option provides Clients with the ability to share a Blackberry device amongst a department or group. Through a web-based application, the Client group manages the user settings of the device to match the current user profile at any given time.

ATCO I-Tek provides full support for product capability including:

- Email
- Voice support
- Calendaring
- Internet access
- File attachment capability

11.10.1 Products or services provided within the fee

The following are included in the price:

- Infrastructure to facilitate e-mail communication with the Blackberry device
- Console to manage the movement of Blackberry devices between designated users

11.10.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Blackberry device
- Procurement and asset management of Blackberry devices if requested

- Device sparing
- Monthly voice and data costs from Third Party Service Provider
- Support of Third Party wireless network Email accounts
- Vendor management
- Setup and management of user settings

11.11 Mobile Information

The Mobile Information service provides Clients with the ability to send documents (i.e. contracts, checklists, company procedures) to designated Client Blackberry devices from a central console. The information received is stored on the Blackberry's internal memory. The services has three options to choose from and are priced separately: Microsoft Outlook Contact list information storage and synchronization, electronic document storage and database storage, and an inclusive option that provides both of these options.

11.11.1 Products or services provided within the fee

The following are included in the price:

- Mobile file synchronization software licenses
- Console to specify files to be synchronized

11.11.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Blackberry device
- Procurement and asset management of Blackberry devices if requested
- Device sparing
- Monthly voice and data costs from Third Party Service Provider
- Support of Third Party wireless network Email accounts.
- Vendor management

11.12 ISDN Circuit

The ISDN Circuit is a telecommunication service that is used in specific geographic areas where data and voice connectivity options are limited.

11.12.1 Products or services provided within the fee

The following are included in the price:

- Telecommunication service, routine maintenance and technology refresh

- Management of contracts with Telecommunication Service Providers
- Infrastructure to support the underlying services
- Capacity planning, design and engineering, technology certification, vendor management, monitoring and support

11.12.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation, cabling, and line and feature costs

11.13 External Web Conferencing

External Web Conferencing (EWC) allows Clients to hold web conferences over the Internet. It is designed to overcome the physical barriers Clients face when presenting information to external customers in different physical locations.

The service supports multi-user voice and video conferencing. Participants can speak to each other through their computer's microphone and speakers. Participants with a USB compatible video camera can also send video. The service provides a sharing feature that allows the Host or Presenter to share documents, applications, or their entire desktop. This feature is ideal for a variety of purposes like training. With the advanced multi-user video, voice and desktop sharing capabilities in EWC, Clients can benefit from a rich online meeting experience.

The service maintains the integrity and privacy of the conference being held.

11.13.1 Products or services provided within the fee

The following are included in the price:

- EWC User ID and Password for creating and managing their web conferences
- Web conference sessions of up to 23 participants at a time
- Web conferencing Client software
- Client Manual

11.13.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Third Party Telecommunications Service Provider fees
- Hardware for voice and video conferencing
- Client Training

11.14 Video Conferencing

Video Conferencing (VC) allows Clients in an ATCO meeting room to place a video conference call to another meeting room in which video conferencing equipment is installed. The service leverages the ATCO Corporate data network, where viable, to provide the connectivity between the video conferencing systems. At locations that do not have sufficient data network bandwidth to support a video conferencing call, Integrated Services Digital Network (ISDN) dialup services can be installed. Clients will have two options for display. The first display option incorporates a 32 inch monitor for video and XVGA (Extended Video Graphics Array) data projector for graphics. The second choice of display is single 46 inch Liquid Crystal Display (LCD) flat screen monitor that can display both video and graphics on the same screen at the same time.

Multipoint conferences consisting of three or more video, audio or a combination of endpoints can be arranged at extra cost by opening a service request.

11.14.1 Products or services provided within the fee

- Operational lease of video conferencing hardware (including microphones and monitor)
- Vendor management including procurement and sparing
- Hardware asset management
- Help Desk support
- Client training at time of delivery
- Break/fix support (during Business Hours)
- Decommissioning and removal of old hardware
- New product investigations and recommendation
- ATCO Corporate IP (Internet Protocol) data connection

11.14.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation and configuration
- Moves/adds/changes
- Support for related items other than standard hardware
- Lease hold improvements
- Monthly operating costs and toll associated with ISDN

11.15 Wide Area Network

11.15.1 General Provisions

The Wide Area Network (WAN) connects a remote site into the ATCO campus network. There are a variety of ways to connect a site to the ATCO Group network. The technology required will depend on the location of the site, the connection facilities available between the remote site, the central network and the Client's requirements. The prices stated here are available in Alberta, except where noted otherwise. Availability of all WAN services offered are dependent upon the capabilities of the Telecommunications Service Provider(s).

11.15.1.1 Products or services provided within the fee

The following are included in the price:

- Remote site hardware such as router(s), Data Service Unit(s) (DSU)/Channel Service Unit(s) (CSU), or analog modems only.
- The core hardware to provide the service are data circuits, router(s), Data Service Unit(s) (DSU)/Channel Service Unit(s) (CSU), or analog modems only.
- Network hardware and software tools used for WAN management.
- Maintenance for hardware and software by a Third Party vendor.
- Hardware and software service support.
- Telecommunications supplier circuit charges at the remote site(s).
- Telecommunications supplier circuit charges at the core (campus).

11.15.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Long distance tolls will be a Specified Expense of telecommunication costs by month by site as invoiced by the Telecommunications Service Provider
- Any one-time setup charge from a Telecommunications Service Provider for new and enhanced site services

11.15.2 56K Virtual WAN

56K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 56 Kbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunications Service Provider.

56K Virtual WAN service provides a cost-effective solution to small remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.2.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (56 Kbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes

11.15.3 112K Virtual WAN

112K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 112 Kbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunication Service Provider.

112K Virtual WAN service provides a cost-effective solution to small/medium remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.3.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (112 Kbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components

- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes

11.15.4 256K Virtual WAN

256K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 256 Kbps in both directions. This is only available at locations in Alberta where Frame Relay is offered by a Telecommunication Service Provider.

256K Virtual WAN service provides a cost-effective solution to small/medium remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.4.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (256 Kbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes

11.15.5 384K Virtual WAN

384K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 384 Kbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunication Service Provider.

384K Virtual WAN service provides a cost-effective solution to small/medium remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.5.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (384 Kbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes

11.15.6 512K Virtual WAN

512K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 512 Kbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunication Service Provider.

512K Virtual WAN service provides a cost-effective solution to medium remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.6.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (512 Kbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network components including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes

11.15.7 768K Virtual WAN

768K Virtual Wide Area Network (WAN) service provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 768 Kbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunications Service Provider.

768K Virtual WAN service provides a cost-effective solution to medium/large remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.7.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (768 Kbps in both directions)
- Unlimited amount of data transfer
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support for included service components

- Core network components including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service
- Moves and changes
- Operation and maintenance of the networking hardware (DSU and WAN router)

11.15.8 1.5M Virtual WAN

1.5M Virtual WAN is a low-speed Wide Area Network (WAN) service that provides a private, dedicated and secure low-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. The maximum line speed is 1.536 Mbps in both directions. This service is only available at locations in Alberta where Frame Relay is offered by a Telecommunication Service Provider.

1.5M Virtual WAN service provides a cost-effective solution to large remote offices where other high-speed WAN services are not available. There is no limit on the amount of data transfer.

11.15.8.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (1.536 Mbps in both directions)
- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (DSU and WAN router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.15.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the Frame Relay service

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- Moves and changes

11.16 Remote Office WAN Acceleration

Remote Office Wide Area Network (WAN) Acceleration provides improved bandwidth utilization to remote offices by reducing the amount of data being transferred and alleviating the inefficiencies inherent in WAN protocol data transfer.

The suitability of WAN Acceleration varies depending upon the application. Some applications requiring encryption may not benefit from the service. In all cases, ATCO I-Tek will work with Clients to determine their requirements, and will recommend the best networking solution to meet their business needs.

11.16.1 Products or services provided within the fee

The following are included in the price:

- Analysis of data traffic transferred between the remote office and the central data servers
- Field test of the WAN accelerator
- Operation and maintenance of the WAN accelerator
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.16.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the WAN accelerator at the remote office
- Moves and changes

11.17 Ethernet LAN Extension

Ethernet Local Area Network (LAN) Extension provides a private, dedicated and secure high-speed connection from the core network in Edmonton and Calgary to remote offices at most locations in Alberta. Speeds available are 10 or 100 Mbps in both directions. This is only available at locations in Alberta where LAN Extension is offered by a Telecommunication Service Provider.

Ethernet LAN Extension service is a multi-service infrastructure that supports data, voice and video at speeds 10 to 100 times faster than traditional WAN services. The multi-service infrastructure moves away from separate data, voice and video networks toward an integrated network, resulting in a cost-effective solution for large remote offices.

11.17.1 Products or services provided within the fee

The following are included in the price:

- Redundant links to both Edmonton and Calgary with automatic fail over
- Bandwidth (speeds available are 10 or 100 Mbps in both directions for different service fees)
- Capped or unlimited amount of data transfer depending on expected volume of traffic
- Operation and maintenance of the networking hardware (Ethernet switch and high-speed router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.17.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time fiber construction cost if applicable
- One time installation costs of the LAN Extension circuit
- Moves and changes

11.18 4-Wire Loop (Short Distance Remote Offices)

4-Wire Loop provides a private, dedicated and secure low-speed point-to-point connection between two offices within a short distance. Typically the 4-Wire Loop service is deployed in a remote location where two offices are relatively close together. By connecting the two offices together using the 4-Wire Loop service, they can reduce network costs by sharing one Wide Area Network (WAN) connection back to Edmonton and Calgary.

Connection speeds between the 2 offices vary from 768 Kbps to 1.536 Mbps depending on quality of line and cable mileage between the two interconnected points. Practical cable distance should be within 5 miles in order to achieve acceptable speed.

11.18.1 Products or services provided within the fee

The following are included in the price:

- Bandwidth (speeds vary from 768 Kbps to 1.536 Mbps depending on line quality and cable mileage)

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- Unlimited amount of data transfer
- Operation and maintenance of the networking hardware (line driver and router)
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components
- Core network access including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components

11.18.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the 4-Wire Loop service
- Moves and changes

11.19 Mobility Aircard

The Mobility Aircard service provides for a secure wireless data connection from the ATCO I-Tek corporate network to a client operated device over a choice of mobility carriers. The application being delivered on the mobile device will determine the particular components and configuration covered by the service offering and the service parameters will be tailored to meet these specific Client requirements.

11.19.1 Products or services provided within the fee

The following are included in the price:

- Secure Private Network Gateway (PNG) internetworking between Mobility carriers and ATCO I-Tek network
- Management of contracts with Telecommunications Service Providers
- Capacity planning, refresh, vendor management, monitoring, and support
- Operation and maintenance of the internetworking hardware (high-speed router and firewall)

11.19.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Special configurations of the firewalls, internetworking routers, and IP address allocation and mapping will be charged at Time and Materials rates.
- Data Transmission limits are determined by the specific application
- Data overages and additional services will be charged under the associated Mobility Aircard Data service

- Airtime (Voice) usage will be charged under the associated Mobility Aircard Airtime service
- Additional fees will apply for untested hardware devices

11.20 Mobility Aircard Data

Mobility Aircard Data provides for the data plan service and usage overages used in conjunction with a Mobility Aircard. Data usage is charged by the mobility Telecommunication Service Provider. An incremental monthly charge will apply and allows for a monthly maximum amount of data to be transferred. The maximum is determined by the by the plan designed to meet specific requirements of the business application. Any use beyond the monthly plan is considered an overage.

11.20.1 Products or services provided within the fee

The following are included in the price:

- Data usage allowed by the mobility plan

11.20.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- All investigations into charges
- Any additional data service or usage charges that are outside of the Mobility Aircard service parameters

11.21 Mobility Aircard Airtime

Mobility Aircard Airtime provides a mechanism for charging any additional airtime used in conjunction with a Mobility Aircard. Airtime is charged by the mobility Telecommunication Service Provider. Typically, a monthly charge applies and allows for a maximum number of minutes to be used per month. The maximum number of minutes is determined by the plan designed to meet specific requirements of the business application.

11.21.1 Products or services provided within the fee

The following are included in the price:

- Airtime allowed by the mobility plan

11.21.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- All investigations into charges

- Any additional airtime charges that are outside of the Mobility Aircard service parameters

11.22 Firewall

The Firewall provides additional network security measures to protect specific networks. Each firewall is uniquely customized according to the client's business needs. Network activities are logged and monitored by skilled network security professionals. Daily firewall logs are archived to a secured and centralized location up to one full year for forensic evidence if needed.

11.22.1 Products or services provided within the fee

The following are included in the price:

- Operation and maintenance of the firewall hardware and software
- Network protection (including workstations, printers, and other specialized devices)
- Logging and monitoring of network activities that are protected by the firewall
- Daily archival of firewall logs

11.22.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the firewall
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Additional network equipment that may be required to connect the protected network(s) to the firewall
- Authentication devices (i.e. key fobs) for Clients requiring network access through the firewall from an outside source

11.23 Firewall – Medium Office

Firewall – Medium Office provides additional network security measures to protect specified networks. The Firewall for Medium Site option is available to remote sites (more than 30 users) that require additional security measures. The high-performance firewall installed by ATCO I-Tek protects up to 100 devices. It has four high-speed network ports to connect multiple physical network segments. More network ports can be purchased if required.

Each firewall is uniquely customized according to the client's business needs. Network activities are logged and monitored by skilled network security professionals. Daily

firewall logs are archived to a secured and centralized location up to one full year for forensic evidence if needed.

11.23.1 Products or services provided within the fee

The following are included in the price:

- Operation and maintenance of the firewall hardware and software
- Network protection (up to 100 devices), including workstations, printers, and other specialized devices
- Up to 4 network ports
- Logging and monitoring of network activities that are protected by the firewall
- Daily archival of firewall logs (up to 1 full year)

11.23.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the firewall
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Additional network equipment that may be required to connect the protected network(s) to the firewall
- Authentication devices (i.e. key fobs) for Clients requiring network access through the firewall from an outside source

11.24 Firewall I380 w/8 Port Unlimited License

The Firewall I380 w/8 Port Unlimited License service is a high-performance firewall solution that provides additional network security measures for operational networks that have specialized devices. This service is available to remote sites and protects an unlimited number of devices.

11.24.1 Products or services provided within the fee

The following are included in the price:

- Operation and maintenance of the firewall hardware and software
- Network protection with unlimited devices including workstations, printers, and specialized devices
- Up to eight network ports to protect multiple network segments
- Logging and monitoring of the network activities protected by the firewall
- Daily archival of firewall logs (up to one full year)

11.24.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the firewall
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Any additional network equipment required to connect the protected network(s) to the firewall
- Authentication devices (i.e. key fobs) for users requiring network access through the firewall from an outside source

11.25 Intrusion Detection – Small Office

The Intrusion Detection (IDS) – Small Office service provides for the detection of malicious network activities such as denial-of-service attacks, port scans, and attacks against services and/or applications that have known vulnerabilities. The IDS – Small Office service compliments a firewall to provide a complete security solution. It is available to remote sites (less than 30 users) requiring additional network security monitoring.

11.25.1 Products or services provided within the fee

The following are included in the price:

- Operation and maintenance of the IDS hardware and software
- Real-time notification of alerts when network attacks are detected
- Logging and monitoring of security events
- Daily archival of event logs (up to 180 days)

11.25.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the IDS system
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Any additional network equipment required to connect the sensors to the network

11.26 Intrusion Detection – Medium Office

The Intrusion Detection (IDS) – Medium Office service provides for the detection of malicious network activities such as denial-of-service attacks, port scans, and attacks against services and/or applications that have known vulnerabilities. The IDS –

Medium Office service compliments a firewall to provide a complete security solution. It is available to remote sites (less than 100 users) requiring additional network security monitoring.

11.26.1 Products or services provided within the fee

The following are included in the price:

- Operation and maintenance of the IDS hardware and software
- Real-time notification of alerts when network attacks are detected
- Logging and monitoring of security events
- Daily archival of event logs (up to 180 days)

11.26.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the IDS system
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Any additional network equipment required to connect the sensors to the network

11.27 Megastream and other Dedicated

Megastream and other Dedicated is a telecommunication service used in specific geographic areas where data and voice connectivity options are limited.

11.27.1 Products or services provided within the fee

The following are included in the price:

- Telecommunication service, routine maintenance and technology refresh
- Management of contracts with Telecommunication Service Providers
- Infrastructure to support the underlying services
- Capacity planning, design and engineering, technology certification, vendor management, monitoring and support

11.27.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation, cabling, line and feature costs

11.28 Modem Line

Modem Line is a telecommunication option that is used in specific geographic areas where data and voice connectivity options are limited.

11.28.1 Products or services provided within the fee

The following are included in the price:

- Telecommunication service, routine maintenance and technology refresh
- Infrastructure to support the underlying services
- Capacity planning, design and engineering, technology certification, vendor management, monitoring and support

11.28.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation, cabling, line and features costs

11.29 Load Limited Meeting Room Switch Rental (Daily or Monthly)

The Load Limited Meeting Room Switch Rental service provides the Client with the ability to connect to the ATCO Production Environment and is by the day or by the month. This is a shared connection and is most often found in meeting and/or training rooms. Performance of this service is dependent upon the number of devices connected. This service is not available to Virtual Private Network (VPN) Small Office sites.

11.29.1 Products or services provided within the fee

The following are included in the price:

- Network connections of up to seven devices (including workstations and printers)
- Installation, operation and maintenance of the hardware

11.29.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves and changes
- Guarantee of the actual bandwidth and network response time

11.30 Office Performance Meeting Room Switch (Daily or Monthly)

The Office Performance Meeting Room Switch Rental service provides the Client with the ability to connect to the ATCO Production Environment with speeds comparable to desktop/office performance, an increased performance compared to the Load Limited Meeting Room Switch Rental. This service requires core switching and CAT5E cabling

at the remote site. Performance of this service is dependent upon the number of devices connected. This service is not available to Virtual Private Network (VPN) Small Office sites.

11.30.1 Products or services provided within the fee

The following are included in the price:

- Network connections of up to twenty devices (including workstations and printers)
- Installation, operation and maintenance of the hardware

11.30.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Horizontal cabling between the office and the wiring closet
- Moves and changes
- Guarantee on the actual bandwidth and network response time

11.31 Internet Service Provider (ISP) Connectivity Rental

The Internet ISP Connectivity Rental service provides the Client with temporary Internet access for a non-ATCO individual (i.e. vendor, contractor, auditor).

11.31.1 Products or services provided within the fee

The following are included in the price:

- Temporary access to the Internet
- Support of standard Internet protocols (HTTP, HTTPS, and FTP)
- Configuration of the switch port

11.31.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Special configuration of the firewall
- Content filtering and usage monitoring
- Protection against harmful Internet content
- Logging and monitoring of network activities
- MSA Service Levels
- Guarantee of the actual bandwidth and network response time

12 VOICE SERVICE

12.1 General Provisions

Voice services provide the ability to meet both standard voice requirements as well as specialized requirements of Call Centres. This includes services such as Sets, Lines, Voice Mail, enhanced features, Call Centre Trunking, and agent seats. These services are available in the Edmonton and Calgary Campus locations as well as the remote offices that have been integrated into the ATCO I-Tek voice network.

12.1.1 Products or services provided within the fee

The following are included in the price:

- Management of Contracts with Telecommunications Service Providers
- Infrastructure to support standard Voice services

12.1.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Special equipment such as headsets & adapters
- Cellular and wireless equipment or services

12.2 Centrex Telephone

The Centrex Telephone service provides a basic business telephone set for use on the Telecommunications Service Provider's Centrex-based telephony service. Centrex Telephone service is used in areas where other services are not provided or for phone system backup.

12.2.1 Products or services provided within the fee

The following are included in the price:

- The telephone set, routine maintenance and technology refresh

12.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The installation, cabling, Centrex line and feature costs
- Telephone add-on modules, headsets

12.3 Call Centre Auto Attendant Applications

The Call Centre Auto Attendant Applications service provides auto attendant functions such as messaging, voice menus, and announcements for call answering applications used within Call Centres. The applications are made available to callers through application connections called "voice ports", and is therefore closely associated with the Call Centre Auto Attendant Ports service.

12.3.1 Products or services provided within the fee

The following are included in the price:

- Auto Attendant software
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support underlying Voice services
- Capacity planning, refresh, vendor management, monitoring, and support

12.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The programming, recording, and configuration of the announcements and messages
- Changes to existing announcements and messages
- Voice ports used to deliver the announcements and messages to the caller
- Special equipment such as headsets and adapters
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.4 Call Centre Auto Attendant Ports

The Call Centre Auto Attendant Ports service provides the delivery mechanisms for the contact centre auto attendant applications messaging and announcements features. The number of concurrent callers accessing the application determines the number of application connections or "voice ports" required. It integrates closely with call processing operating systems.

12.4.1 Products or services provided within the fee

The following are included in the price:

- Auto Attendant ports
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support the underlying Voice services

- Capacity planning, technology certification, refresh, vendor management, monitoring, and support

12.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The programming, recording, and configuration of the announcements and messages
- Changes to existing announcements and messages using the ports
- Applications containing the announcements and messages to the caller
- Special equipment such as headsets and adapters
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.5 Call Centre Readerboard

The Call Centre Readerboard service provides a customizable, 32 x 128 pixel visual display (up to 4 lines visible at once) of real time Call Centre statistics, like average speed of answer and number of calls waiting. It is integrated closely with the call processing operating system.

12.5.1 Products or services provided within the fee

The following are included in the price:

- Call Centre Readerboard server
- Management of contracts with Telecommunication Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- The programming and configuration of the displays and messages
- Changes to existing displays and messages

12.6 Voice Call Centre Set Charges

The Call Centre Set provides Clients with the ability to utilize telephone sets specifically for Call Centre operations.

12.6.1 Products or services provided within the fee

The following are included in the price:

- The telephone set, routine maintenance and technology refresh
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.6.2 Products or services not provided within the fee (Additional charges will apply)

- The installation, cabling, line and feature costs
- Telephone add-on modules and headsets
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.7 Call Centre Application

The Call Centre Application service provides the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within Call Centres. It integrates closely with the other Call Centre services. The application allows the supervisor to view and manage a wide range of aspects of the Call Centre such as agent and queue statistics in real-time, print a wide variety of standard and customizable reports, execute changes to automatic call distribution parameters.

12.7.1 Products or services provided within the fee

The following are included in the price:

- Software license
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning, technology certification, refresh, vendor management, monitoring, and support

12.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The design, programming, and configuration of the application
- Changes to existing applications.
- The hardware used to deliver the applications to the caller and the Call Centre
- Special equipment such as headsets and adapters

- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.8 Call Centre Server

The Call Centre Server service provides the hardware utilized by the Call Centre application. It is the delivery mechanism for the centralized call flow control, monitoring, reporting, agent assignment and supervision applications used within Call Centres. It integrates closely with the other Call Centre services.

12.8.1 Products or services provided within the fee

The following are included in the price:

- Call Centre servers
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The application software
- Special equipment such as headsets and adapters
- Cellular and wireless equipment or services for this equipment
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.9 Call Centre Trunking

The Call Centre Trunking service provides the telephone system capacity that is measured in trunking channels. Trunking is a method of using specialized communication channels for a large number of potential users/calls. The number of trunk channels used during the peak hours of the month are charged for this service. The Call Centre will have the ability to set a maximum on the number of trunk channels used. Any incoming calls over the maximum established by the Call Centre will receive a busy signal.

12.9.1 Products or services provided within the fee

The following are included in the price:

- Trunk infrastructure hardware

- Telecommunications Service Provider facility charges
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support underlying Voice services
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.9.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Long distance charges
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.10 Custom Music-on-Hold

The Custom Music-On-Hold service provides a license to play music to a single caller on hold in a phone queue. A separate license is required for each simultaneous caller who receives an announcement in the phone queue.

12.10.1 Products or services provided within the fee

The following are included in the price:

- A license to play music to a single caller on hold in a phone queue
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support standard Voice services
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.10.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Music from a Third Party provider and the maintenance for the recording

12.11 Dedicated Off Premise Extension (OPX)

The Dedicated Off Premise Extension (OPX) service provides a method of connecting a telephone set located at a geographically different location from the host telephone system. The charge is based on the Telecommunication Service Provider's cable mileage from the originating location to the location of the extension

12.11.1 Products or services provided within the fee

The following are included in the price:

- A telephone circuit that is used to connect a telephone set at a remote location to a campus PBX (Private Branch Exchange). This is the circuit that is dedicated to the telephone set at the remote location.

12.11.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The installation, cabling, line and feature costs
- Telephone add-on modules and headsets
- Any specialized telephony system hardware and software required for the service

12.12 Dedicated Tie Lines

The Dedicated Tie Lines service provides circuits between Private Branch Exchanges (PBX). These circuits provide the capability to dial between the locations by entering an access code followed by a local number on the "called" PBX. Prices will be determined based on site-specific requirements and reviewed on a site by site basis; the charge is based on cable mileage for the circuit from end-point to end-point including distance to and from Central Office(s).

12.12.1 Products or services provided within the fee

The following are included in the price:

- Circuits between PBX switches at two locations

12.12.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time setup, programming, configuration, and installation
- Special equipment for interfacing to a Telecommunications Service Provider's facilities required to utilize the system

12.13 Recorded Announcement

The Recorded Announcement service provides the storage and playback hardware for recorded announcements.

When a called number is busy, callers who wish to stay on hold are directed to a recording followed by music. The number of concurrent calls which can be directed to the announcement is based on the number of simultaneous announcement licenses purchased. A separate license is required for each simultaneous caller who receives an announcement in the phone queue.

12.13.1 Products or services provided within the fee

The following are included in the price:

- Storage device for the announcement
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.13.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Recording of the announcement
- Changes to the existing announcements

12.14 Recorded Announcement Route

The Recorded Announcement License provides the license to play an announcement to a single caller in a phone queue.

12.14.1 Products or services provided within the fee

The following are included in the price:

- License fee
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.14.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Recorded Announcement service is a prerequisite for this service

12.15 Remote Centre Voice Network Access

The Remote Centre Voice Network Access service provides the ability to connect remote telephone users to either the Edmonton or Calgary campus. The remote telephone users have access to the same telephone features and functions as campus telephone users.

The fee for this service encompasses the Telecommunications Service Provider's charge for the connection between the remote users and the major campus.

12.15.1 Products or services provided within the fee

The following are included in the price:

- Connection between remote telephone users and major campus

- Capacity planning and design, refresh, vendor management, monitoring, and support

12.15.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Set-up and installation

12.16 Telecom Circuit Fees

The Telecom Circuit Fees service is used to provide a method of directing a variety of voice circuit charges including Centrex and individual business lines from the Telecommunications Service Providers to the Client.

12.16.1 Products or services provided within the fee

The following are included in the price:

- Management and set up of the service
- Management of the Service Provider contracts

12.16.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- This is a billing mechanism and therefore any associated elements are excluded.
- Any and all investigations into charges

12.17 Voice Line Charges

The Voice Line Charge service provides the local number that appears on each set, modem, fax, ACD (Automatic Call Distribution) queue, script, or other service to connect to another unit within the local telephone system or Public Switch Telephone Network (PSTN). If this number is to appear on another device then a Line Appearance service fee is charged.

12.17.1 Products or services provided within the fee

The following are included in the price:

- One telephone line allowing calls to be made inside the campus or outside the campus as allowed by the supervisor
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.17.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Long distance charges

12.18 Voice AIN Auto Activation Fee

The Voice AIN Auto Activation Fee service provides the ability for ATCO I-Tek to activate the AIN service remotely on behalf of Clients. It is closely associated with the Voice AIN Redirect Line Charge service that provides the ability to reroute a predefined telephone number or numbers to one or more alternate telephone numbers. The service is invoked by ATCO I-Tek through the associated Voice AIN Auto Activation service and is typically used for Business Continuity and Disaster Recovery applications.

12.18.1 Products or services provided within the fee

The following are included in the price:

- Management of contracts with Telecommunication Service Providers
- Predefined routing table, indicating 'to' and 'from' telephone numbers

12.18.2 Products or services not provided within the fee (Additional charges will apply)

- One time setup, programming and configuration of the redirection table
- Installation, cabling, telephone line(s), long distance and feature costs of the associated telephone numbers
- Investigation in to charges

12.19 Voice AIN Redirect Line Charge

The Voice AIN Redirect Line Charge service provides the ability for ATCO I-Tek to reroute a predefined telephone number or numbers to one or more alternate telephone numbers. The service is invoked by ATCO I-Tek through the associated Voice AIN Auto Activation service and is typically user for Business Continuity and Disaster Recovery applications.

12.19.1 Products or services provided within the fee

The following are included in the price:

- Management of contracts with Telecommunication Service Providers
- Predefined routing table, indicating 'to' and 'from' telephone numbers

12.19.2 Products or services not provided within the fee (Additional charges will apply)

- One time setup, programming and configuration of the redirection table

- Installation, cabling, telephone line(s), long distance and feature costs of the associated telephone numbers
- Investigation into charges

12.20 Voice Feature – Line Appearance

The Line Appearance service provides the ability to configure multiple telephone sets with the same local number. One telephone set will be charged for a "Voice Line Charge" service and the others will each receive "Voice Set Features - Line Appearance" charges.

12.20.1 Products or services provided within the fee

The following are included in the price:

- Provisioning of line on telephone sets
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.20.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Voice line charge
- Voice Line setup

12.21 Voice Feature – Voice Mail Basic

The Voice Mail Basic service provides a Client with the basic voice mail functions like multiple greetings; leaving, listening and managing messages; and password protection on the voice mail box.

12.21.1 Products or services provided within the fee

The following are included in the price:

- A voice mail box for one local number with telephone set access
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.21.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Voice Feature – Voice Line Charge is a prerequisite for this service
- Installation, moves, adds, and changes

12.22 Voice Feature – Voice Mail Desktop

The Voice Mail Desktop service provides access to the ATCO I-Tek provided corporate voice mail through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Capability includes displaying and managing a list of voice mail messages in an Inbox email format.

12.22.1 Products or services provided within the fee

The following are included in the price:

- Voice mail server
- Software distribution to the desktop
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support

12.22.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Basic voice mail is a prerequisite for this service.

12.23 Voice Feature – Voice Mail Fax

The Voice Mail Fax service provides incoming fax capability through the Microsoft Outlook email application on a standard ATCO I-Tek provided personal computer. Fax messages are displayed in a standard Inbox email format.

12.23.1 Products or services provided within the fee

The following are included in the price:

- Voice mail fax server
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support

12.23.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Basic voice mail and voice mail desktop are prerequisites for this service
- Configuration of the voice mail system
- A separate FAX number is required

12.24 Voice Feature – Voice Mail Remote Notify

The Voice Mail Remote Notify service provides a notification that the Client has received a voice mail through the corporate voice mail system. The notification can be an automated voice call, pager notification, or ATCO I-Tek Corporate email message

12.24.1 Products or services provided within the fee

The following are included in the price:

- Voice mail remote notify server
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support

12.24.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Basic voice mail is a prerequisite for this service
- Voice mail desktop is a prerequisite for email notification
- Configuration of the voice mail system
- A separate voice line may also be required in special situations

12.25 Voice Install Move/Add/Change (VIMAC / Voice IMAC)

The Voice IMAC services provide for the alteration of location or configuration of a telephone set, modem, or fax machines as requested by the Client.

12.25.1 Products or services provided within the fee

The following are included in the price:

- Action (install, move, add, or change) that is requested by the Client

12.25.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Any wiring that may be needed
- Any travel required

12.26 Long Distance Direct

The Long Distance Direct service provides the Client with access to a service that is managed on the Clients behalf with the Telecommunications supplier that meets the Clients diverse needs. The total fees for Long Distance will be charged based on the number of calls, length of the calls and the location called. The Long Distance Direct

rate for North America will be billed a standard rate. International Call will be billed based upon location and time of day. The invoice presentation may vary slightly due to call duration rounding.

12.26.1 Products or services provided within the fee

The following are included in the price:

- Access to long distance calling to the Public Switch Telephone Network (PSTN)
- Contract negotiation and third party contract management
- Third Party invoice reconciliation and contract management
- Reporting
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support

12.26.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Credit cards (calling cards) are managed directly by the Clients
- Dispute resolution and investigation

12.27 Voice Set Charges

The Voice Set provides Clients with a standard business telephone set.

12.27.1 Products or services provided within the fee

The following are included in the price:

- The telephone set, routine maintenance and technology refresh
- Management of contracts with Telecommunications Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring, and support

12.27.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- The installation, cabling, line and feature costs
- Telephone add-on modules, headsets
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.28 Voice Set Feature – Call Park

Call Park provides the ability to place a call on hold that can be answered on any set anywhere within the local campus area. This is typically used to answer calls, place them on hold, and then broadcast a request on a Public Address System for a person to answer a call on a specific line. The person answering can use any phone in the local campus area to dial in the identified line number to collect the call.

12.28.1 Products or services provided within the fee

The following are included in the price:

- Call park feature on the phone set

12.28.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- The Public Address System is the responsibility of the Client

12.29 Voice Feature – Call Recording

Call Recording provides the ability to record a telephone conversation. Storage service fees are charged when a call is recorded. The Client has the option to record all calls or record on a call-by-call basis as determined by their business requirements.

Archiving storage is optional. This service stays in place until permission is given to clean up the files or an automated clean up occurs; currently every 91 days.

12.29.1 Products or services provided within the fee

The following are included in the price:

- Capability to record phone calls
- Management, support, and training on the retrieval system and short-term storage of the recordings
- Capacity planning and design, refresh, vendor management, monitoring, and support

12.29.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Storage of calls
- Archiving services to permanent media

12.30 Voice Feature – Call Recording Archive

Voice Feature – Call Recording Archive provides Clients with the option of archiving voice call recordings to DVD media, on a per set basis.

12.30.1 Products or services provided within the fee

The following are included in the price:

- Archival of voice call recordings to DVD media
- Management, support, and training of the archival system
- Creation of DVD recordings
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring and support

12.30.2 Products or services not provided within the fee (Additional charges will apply)

- Voice Feature – Call Recording is a prerequisite service
- Storage of DVD media (Client's responsibility)

12.31 Voice Set Feature – Speed Call Manager

Speed Call Manager provides the ability to create, edit and audit "Speed Call Lists". A Speed Call List is a table of frequently called numbers. Once the Speed Call List is set up, Clients can call the telephone number by pressing the Speed Dial key on their telephone set and entering the 2-digit code to complete the dialling of the call. Both domestic and international numbers can be put into a Speed Call List. In order for other users to access the Speed Call List (s), the Client must request the Speed Call User service for those users.

12.31.1 Products or services provided within the fee

The following are included in the price:

- Speed Call Manager feature on telephone set

12.31.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Programming of Speed Call Lists
- Speed Call User service

12.32 Voice Set Feature – Speed Call User

Speed Call User provides the Client access to a telephone's Speed Call List. Once the Speed Call List is set up by the Speed Call Manager, the Client can call the telephone number by pressing the Speed Dial key on their telephone set and entering the 2-digit code to complete the dialling of the call. Both domestic and international numbers can be put into a Speed Call List. In order for other users to access the Speed Call List(s), the Client must request the Speed Call Manager service to set up the Speed Call List(s) for those users.

12.32.1 Products or services provided within the fee

The following are included in the price:

- Speed Call User feature on telephone set

12.32.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation
- Speed Call Manager

12.33 Voice Set Feature – Visual Call Waiting

Visual Call Waiting provides the display of an incoming number on the Voice Set while the Client is on a line with another caller.

12.33.1 Products or services provided within the fee

The following are included in the price:

- Visual Call Waiting feature on a telephone set

12.33.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation

12.34 Voice Telecom Fee

The Voice Telecom Fee is used to provide a method of charging costs that are not directly attributed to circuits. These are fees typically associated with the installation, repair or maintenance of voice and data services. For non-circuit voice-related charges, services could include installation or one-off services. A line item in this service might contain an amalgamation of several charges into one line item.

12.34.1 Products or services provided within the fee

The following are included in the price:

- Setup and management

12.34.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- This is a billing mechanism and therefore any associated elements are excluded
- Any investigations into charges

12.35 Cordless Telephone Set Charge

The Cordless Telephone Set Charge provides Clients with a short range wireless telephone that supports standard voice business features.

12.35.1 Products or services provided within the fee

The following are included in the price:

- Cordless telephone set, routine maintenance and technology refresh
- Management of contracts with Telecommunication Service Providers
- Infrastructure to support the underlying Voice services
- Capacity planning, design and engineering, technology certification, vendor management, monitoring and support

12.35.2 Products or services not provided within the fee (Additional charges will apply)

- Installation, cabling, line and feature costs
- Telephone add-on modules
- Headsets
- Alteration of any existing Voice service to meet the unique requirements of a Call Centre

12.36 Audio Conference Set Charge

The Audio Conference Set Charge provides Clients with a device designed for use with hands-free / multiple participation, audio conferencing applications.

12.36.1 Products or services provided within the fee

The following are included in the price:

- Audio conference device (includes microphones built into device) with capability of adding up to two external microphones
- Routine maintenance and technology refresh
- Management of contracts with Telecommunication Service Providers.
- Infrastructure to support the underlying Voice services
- Capacity planning, design and engineering, technology certification, vendor management, and monitoring

12.36.2 Products or services not provided within the fee (Additional charges will apply)

- Installation, cabling, line and feature services
- Additional external microphones
- Multi-point audio conferencing services

12.37 Audio Conference Port Fee

The Audio Conference Port Fee provides the connection mechanism for participants in an audio conference. The number of concurrent callers determines the number of connections or "audio conference ports" required.

12.37.1 Products or services provided within the fee

The following are included in the price:

- Each port provides one connection into a scheduled audio conference session
- Invoice administration
- Capacity planning, technology certification, refresh, vendor management, monitoring and support

12.37.2 Products or services not provided within the fee (Additional charges will apply)

- Consultation, setup, and booking of the scheduled conference and facilities
- Telephone line(s), feature(s), or long distance charges

12.38 Audio Conference Cancellation Fee

The Audio Conference Cancellation Fee is charged when a dedicated Audio Conference service reservation is cancelled by the Client without a two business day cancellation notice. The fee charged is dependent upon the number of ports reserved and the duration of the Audio Conference.

12.38.1 Products or services provided within the fee

The following are included in the price:

- Ports and duration for the scheduled Audio Conference service being cancelled

12.38.2 Products or services not provided within the fee (Additional charges will apply)

- This is a billing mechanism and therefore any associated elements are excluded
- Investigation into charges

12.39 Private Branch Exchange Trunk Port

The Private Branch Exchange (PBX) Trunk Port service provides specialized infrastructure that is required for connecting a PBX to a Telecommunication Service Provider's facility. This service is typically required for the connection of Tie Lines between PBX's and/or other telecommunication systems.

12.39.1 Products or services provided within the fee

The following are included in the price:

- Telephony system hardware and software required for the service
- Capacity planning, design and engineering, technology certification, refresh, vendor management, monitoring and support

12.39.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- One time setup, programming, configuration and installation
- Any associated telecommunication facilities (circuits)

12.40 Remote Call Centre Base

The Remote Call Centre Base service provides the ability to connect remote Call Centre agents to the primary Call Centre. The remote agents have access to the same Call Centre features and functions as the primary Call Centre agents.

12.40.1 Products or services provided within the fee

The following are included in the price:

- Hardware to deliver the Call Centre features and functions
- Infrastructure to support the underlying Voice services
- Capacity planning, technology refresh, vendor management, monitoring, and support

12.40.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Installation of cabling, line and feature costs
- Design , programming and configuration of the application
- Changes to existing applications
- Specialized equipment (i.e. headsets and adapters)
- Alteration of any existing Voice services
- Backup infrastructure and facilities

13 WORKSTATION SERVICE

13.1 General Provisions

Workstation Services provides the hardware and support for the computing equipment located within the office environment. This section outlines the services and the rates for Laptops, Desktops, Monitors, Printers, Multifunction devices and their associated support. Only hardware and software that is procured or approved by ATCO I-Tek may be installed on a workstation. Equipment specifications are subject to change without notice as technology changes.

13.2 Desktop PC Hardware Lease

The Desktop PC Hardware Lease provides the Client with the standard PC (personal computer) lease to conduct business. PC specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

13.2.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of PC hardware with 4 year refresh
- One cascade of the PC to new user at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- Product sparing
- Hardware asset management
- Hardware installation
- Testing and integration
- Infrastructure management
- Workstation management
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations (hardware and software integration)
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

- The target delivery for a standard Desktop will be 15 business days, subject to order completion, order approval and vendor delivery

13.2.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Special hardware requested by the Client
- Wiring for new locations

13.3 High Performance Desktop PC Hardware Lease

The High Performance Desktop PC Hardware Lease provides the Client with the more powerful PC (personal computer) lease to meet resource intensive application requirements. PC specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

13.3.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of PC hardware with 4 year refresh
- One cascade of the PC to new user at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- Product sparing
- Hardware asset management
- Hardware installation
- Testing and integration
- Infrastructure management
- Workstation management
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations (hardware and software integration)
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

13.3.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than workstation hardware
- Special hardware requested by the Client
- Wiring for new locations

13.4 Desktop PC Support

Desktop PC Support provides all services relating to the support of the leased desktop personal computer. There are three levels of PC support: low, medium, and high. The level of support needed is determined by the business needs of the Client. For all three levels, the Core software applications are supported. A list of Core software applications included in the Desktop PC Support rate is maintained and updated by ATCO I-Tek on a regular basis and is published on the Client Site intranet. Any software applications required in addition to the Core group is considered "above Core".

The Level of support is determined as follows:

- 0-4 software applications: PC Support Low
- 5-8 software applications: PC Support Medium
- 9+ software applications: PC Support High

Exceptions:

- Clients with Desktops that are not connected to the ATCO I-Tek network will be billed for PC Support at the MEDIUM level

13.4.1 Products or services provided within the fee

The following are included in the price:

- Standard Desktop build
- Core software installation and support
- 24x7x365 Level 1 Help Desk Support
- Core software asset management
- Core software standards review, selection and configuration
- Core software testing, integration, installation and maintenance
- Core software license
- Core software suite and Windows software updates/patches for functional and/or security purposes
- Anti-Virus software updates
- Locked down configuration

- Standard configuration management
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- LAN/WAN environment access
- Technology roadmap and recommendations

13.4.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Hardware fees
- Wiring for new locations
- Any major upgrade in Core software that would result in rework of current standard workstation build or architecture change (this will be managed through the standard SOW process)
- Any support efforts when related to Clients with administrative access or multi-platform configurations
- Any non-standard operating system builds
- Support for above Core software applications

13.5 Laptop Hardware Lease

The Laptop Hardware Lease provides the Client with the standard laptop lease for the Client to conduct business. Laptop specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

13.5.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of laptop hardware with 4 year refresh
- One cascade of the laptop to new user at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- Product sparing
- Hardware asset management
- Hardware installation

- Testing and integration
- Infrastructure management
- Workstation management
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware
- The target delivery for a standard Desktop will be 15 business days, subject to order completion, order approval and vendor delivery

13.5.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Special hardware requested by the Client
- Wiring for new locations

13.6 Ruggedized Laptop Hardware Lease

The Ruggedized Laptop Hardware Lease provides the Client with a Ruggedized laptop lease where there is a client business requirement for a rugged laptop. Ruggedized Laptop specifications are subject to change without notice as technology changes. There may be different ruggedized offerings based upon required functionality.

13.6.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of rugged laptop hardware with 4 year refresh
- One cascade of the rugged laptop to new user at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- Product sparing
- Hardware asset management
- Hardware installation

- Testing and integration
- Infrastructure management
- Workstation management
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

13.6.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Special hardware requested by the Client
- Wiring for new locations

13.7 Laptop Slim Hardware Lease

The Laptop Hardware Slim Lease provides the Client with the standard slim laptop lease for the Client to conduct business. The slim laptop is smaller and lighter weight than its standard issue counterpart. Laptop specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

13.7.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of laptop hardware with 3 year refresh
- One cascade of the laptop to new Client at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- New product and services consultation, investigation and recommendation
- Product sparing
- Hardware asset management
- Hardware installation

- Testing and integration
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

13.7.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Special hardware requested by the Client
- Wiring for new locations

13.8 Laptop Support

The Laptop Support service provides all services relating to the support of the leased laptop. There are three levels of laptop support: low, medium, and high. The level of support needed is determined by the business needs of the Client. For all three levels, the Core software applications are supported. A list of Core software applications included in the Laptop Support rate is maintained and updated by ATCO I-Tek on a regular basis and is published on the Client intranet website. Any software applications required in addition to the Core group is considered "above Core".

The Level of support is determined as follows:

- 0-4 software applications: Laptop Support Low
- 5-8 software applications: Laptop Support Medium
- 9+ software applications: Laptop Support High

Exceptions:

- Clients with laptops that are not connected to the ATCO I-Tek network will be billed for Laptop Support at the MEDIUM level.

13.8.1 Products or services provided within the fee

The following are included in the price:

- Standard Laptop build
- Core software installation and support
- 24x7x365 Level 1 Help Desk Support

- Core software asset management
- Core software standards review, selection and configuration
- Core software testing, integration, installation and maintenance
- Core software licensing
- Core software suite and Windows software updates/patches for functional and/or security purposes
- Technology roadmap and recommendations
- Anti-Virus software updates
- Locked down configuration
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- LAN/WAN environment access

13.8.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Hardware fees
- Wiring for new locations
- Any major upgrade in Core software that would result in rework of current standard workstation build
- Any support efforts when related to Clients with administrative access or multi-platform configurations
- Any non-standard operating system builds
- Support for above Core software applications may be billable

13.9 Hard Drive Encryption

Hard Drive Encryption option protects confidential data on a workstation's hard drive through full disk encryption. Hard Drive Encryption prevents the information on a workstation's hard drive from being accessed if it is lost or stolen. This service is available for both desktop and laptop computers.

13.9.1 Products or services provided within the fee

The following are included in the price:

- Full hard drive encryption

- Software licenses and maintenance
- Software deployment and setup
- 24x7x365 Level 1 Help Desk Support
- Centrally managed environment
- Resetting forgotten passwords

13.9.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Client Training

13.10 Monitor LCD

The Monitor LCD (Liquid Crystal Display) Lease provides a standard LCD monitor for the Client to conduct business. LCD monitors are compact, lightweight and consume less energy than CRT (Cathode Ray Tube) monitors. Monitor specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

LCD Monitor service offerings consist of the following:

- 17 inch LCD (end of life)
- 19 inch LCD
- 20 inch LCD
- 24 inch LCD
- 27 inch LCD
- 30 inch LCD

13.10.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of monitor hardware with 4 year refresh
- One cascade of the monitor to new Client at time of refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- New product and services consultation, investigation and recommendation
- Product sparing
- Hardware asset management
- Hardware installation

- Testing and integration
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Removal and disposal of retired hardware

13.10.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Non-standard hardware requested by the Client
- Wiring for new locations

13.11 Monitor CRT (end of life)

The Monitor CRT lease provides the Client with a standard CRT (Cathode Ray Tube) monitor. CRT technology is being replaced by LCD (Liquid Crystal Display) technology. This lease serves those Clients who have a requirement for CRT monitors. This service is end of life and will be removed when all CRT monitors have been refreshed by December 31, 2010.

CRT Monitor service offerings consist of the following:

- 17 inch CRT (end of life)
- 21 inch CRT (end of life)

13.11.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of monitor hardware with 4 year refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- New product and services consultation, investigation and recommendation
- Hardware asset management
- Hardware installation
- Testing and integration
- 24x7x365 Level 1 Help Desk Support

- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Removal and disposal of retired hardware

13.11.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Non-standard hardware requested by the Client
- Wiring for new locations

13.12 Software Integration and Packaging

Software Integration and Packaging provides the Client with a process to test, integrate and package new software for use in the ATCO environment. After the integration testing, the entire application is captured in a package that allows for the electronic distribution to the Client's workstation. This approach delivers consistent reliability across the workstation environment and also significantly reduces the time to recover in the event of a failure.

ATCO I-Tek reserves the right to deny the installation of any software product that may present risk and compromise the quality or effectiveness of any service in the networked environment. All exceptions are handled through the ATCO Group Standards Exception Process and are handled on a *Time and Materials basis*.

13.12.1 Products or services provided within the fee

The following are included in the price:

- Integration testing with the standard operating system and Core applications
- Packaging of the application to allow for electronic distribution
- One distribution to the client tester of the application
- Elevation into production so it is available for future distribution request

13.12.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Software distribution over and above the one to the client tester
- Cost of the software license fee

- Upgrades to a newer version or release of software

13.13 Software Distribution Fee

Software Distribution provides the Client with electronic distribution and installation of packaged software to a standard ATCO workstation

13.13.1 Products or services provided within the fee

The following are included in the price:

- Distribution of application to Client workstation
- License management of packaged software product on standard workstation
- Removal of software when requested
- Option to bundle requests to access group pricing

13.13.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Software license fee
- Upgrades to a newer version or release of software
- Software Integration and Packaging

13.14 Printers

ATCO I-Tek provides various types of printers to meet specific business requirements of its Clients. Printer specifications are published on the Client Site intranet. These specifications are subject to change without notice as technology changes.

The printer options are:

- Low Volume Black and White Printer
- Medium Volume Black and White Printer
- High Volume Black and White Printer
- Low Volume Colour Printer
- Medium Volume Colour Printer
- High Volume Colour Printer
- Maximum Volume Colour Printer (supports 11x17 paper)

13.14.1 Products or services provided within the fee

The following are included in the price:

- Operational lease of printer hardware with 6 year refresh

- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- New product and services consultation, investigation and recommendation
- Product sparing
- Hardware asset management
- Hardware installation
- Testing and integration
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Removal and disposal of retired hardware
- Workstation connected (Low Volume only); all others network connected

13.14.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Non-standard hardware requested by the Client will be charged Time and Materials Rates to build and install
- Wiring for new locations
- Consumables, i.e., toner, fusers

13.15 Printer Support

Printer Support provides all services relating to the support of a leased printer. There are three types of Printer Support: Low, Medium and High. The type of support needed is determined by the type of printer being used. Low Printer Support is for low volume color and black and white printers. Medium Printer Support is for standard color and black and white printers. High Printer Support is for high and maximum volume color and black and white printers. Pricing is based on the level of support.

13.15.1 Products or services provided within the fee

The following are included in the price:

- Print queue setup and management

- Software integration within the standard environment
- Testing of Core software applications with printer
- 24x7x365 Level 1 Help Desk support
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- Network connected, where applicable

13.15.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Consumable, i.e., toner and fusers
- Printer software integration and drivers for above Core software applications

13.16 Xerox Lease

ATCO I-Tek provides various types of Xerox devices to meet the business requirements of its Clients. Specifications are reviewed with the Client as part of the consulting process that is followed when recommending the appropriate device. Equipment specifications are subject to change without notice as vendor technology changes. Xerox devices are leased through a five year committed term. The Xerox equipment is supported through the ATCO I-Tek Customer Support Centre.

13.16.1 Products or services provided within the fee

The following are included in the price:

- Five year lease of the hardware
- Hardware review, selection and configuration
- Hardware vendor management including procurement
- New product and services consultation, investigation and recommendation
- Hardware asset management
- Hardware installation
- Testing and integration
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Removal and disposal of retired hardware

13.16.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Connection to the ATCO I-Tek network
- All support and service related items other than hardware
- Non-standard hardware requested by the Client will be charged Time and Materials Rates to build and install
- Wiring for new locations
- Consumables, i.e., toner, fusers

13.17 Xerox service

Xerox Service provides comprehensive support for all Xerox fax, copier and multifunction units based upon a per impression cost. Xerox service also includes the supply of applicable toner and waste containers for the device. The Xerox equipment is supported through the ATCO I-Tek Customer Support Centre.

13.17.1 Products or services provided within the fee

The following are included in the price:

- Comprehensive hardware and software support for the Xerox device
- Toner and toner waste containers
- Fax drums for all fax machines leased after Oct 1, 2005

13.17.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Connection to the ATCO I-Tek network
- Xerox Printer Support
- Certain Consumables i.e.: Staples, Paper
- Installation of toner and waste toner containers
- Fax drums for fax machines leased before Oct 1, 2005

13.18 Xerox Printer Support

Xerox Printer Support provides all services relating to the support of a leased Xerox multifunction device. High volume Xerox printers require more configuration. Xerox devices have two levels of printer support depending on the type of device:

- Xerox Printer Support
- High Volume Xerox Printer Support

13.18.1 Products or services provided within the fee

The following are included in the price:

- Print queue setup and management
- Software integration within the standard environment
- Testing of Core software applications with printer
- Device Configuration (Setup print, faxing, scan, or copy)
- 24x7x365 Level 1 Help Desk support
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- Training on newly installed devices
- Adding a new device or changing a device configuration

13.18.2 Products or services not provided within the fee (Additional charges will apply)

The following are excluded from the price:

- Consumable, i.e., toner and fuses
- Printer software integration for above Core software applications
- Moves

13.19 Xerox Consumables

Xerox Consumables provides consumables that are excluded from the Xerox service Fee for Xerox devices. These consumables (example: staples, paper) may be requested by the Client through a service request.

13.20 Printer Toner/Ink

Printer Toner/Ink provides toner/ink for print devices that are leased or purchased through ATCO I-Tek by the Client. Toner/Ink may be requested by the Client through a service request.

13.21 Workstation Install/Move/Addition/Change

This fee is a charge associated with Client requested installs, moves, adds or changes during normal business hours, that are not included within a standard service.

Some examples of where this fee may be applicable are:

- Cascade (when not considered part of the refresh cycle) or move of workstations
- Addition of a single component to an existing workstation

14 APPLICATION MANAGED SERVICE (AMS) PRICING

The following table is to demonstrate base level pricing during the term of the contract (in 2009 Canadian dollars). Reference Section 5.2. Billing metric is $ per month.

14.1 General (Excluding Application Disaster Recovery)

Co.	App. Code	Description	2010 - 2015 AMS Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
1	2	Work Management Phase 1 (Advantex system)	$7,632	$7,540	$7,450	$7,361	$7,272	$7,185
	2	Work Management Phase 2 (Stages 1 and 2)	$77,700	$76,768	$75,846	$74,936	$74,037	$73,149
	3	Non Gas Sales Information System	$230	$227	$225	$222	$219	$217
	4	CAD (Computer Aided Dispatch)	$46,300	$45,744	$45,195	$44,653	$44,117	$43,588
	10	Payroll Human Resources System	$2,300	$2,272	$2,245	$2,218	$2,192	$2,165
	11	Benefits Administration System	$2,570	$2,539	$2,509	$2,479	$2,449	$2,419
	12	Employee Biographics System	$940	$929	$918	$907	$896	$885
	13	Payroll Distribution System	$130	$128	$127	$125	$124	$122
	15	Time Entry System	$500	$494	$488	$482	$476	$471
	16	Job Costing System	$100	$99	$98	$96	$95	$94
	20	BARS/Khalix	$1,872	$1,850	$1,827	$1,805	$1,784	$1,762
	27	IRIS	$33,172	$32,774	$32,381	$31,992	$31,608	$31,229
	29	Property Tax System	$100	$99	$98	$96	$95	$94
	41	Landman	$1,588	$1,569	$1,550	$1,532	$1,513	$1,495
	51	PC Automate	$1,822	$1,800	$1,779	$1,757	$1,736	$1,715
	62	Gas Engineering (LAMS XP)	$250	$247	$244	$241	$238	$235
	66	FA Suite	$5,852	$5,782	$5,712	$5,644	$5,576	$5,509
	67	Daily Forecasting Settlement (DFSS)	$31,602	$31,223	$30,848	$30,478	$30,112	$29,751
	AG	Gas Valve Inspection (formerly Valve Inspection Tracking)	$160	$158	$156	$154	$152	$151
	AJ	TRIM Context	$988	$976	$964	$953	$941	$930
	AV	Safe Work Management System	$350	$346	$342	$338	$333	$329

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Co.	App. Code	Description	2010 - 2015 AMS Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
	AW	Surface Lease Management System (SLMS)	$150	$148	$146	$145	$143	$141
	AX	Standards and Quality Assurance Database	$100	$99	$98	$96	$95	$94
	BL	Reg Station Inspections	$1,590	$1,571	$1,552	$1,533	$1,515	$1,497
	BQ	Quality Assurance Audit	$100	$99	$98	$96	$95	$94
	BT	ProjectWise	$1,672	$1,652	$1,632	$1,613	$1,593	$1,574
	BV	Pressure Factor Measurement System	$180	$178	$176	$174	$172	$169
	BW	PremierPlus4	$1,672	$1,652	$1,632	$1,613	$1,593	$1,574
	CG	Gas Odorant Tracking System	$100	$99	$98	$96	$95	$94
	CH	Natural Gas Vehicle Billing	$450	$445	$439	$434	$429	$424
	CK	Managerial Reporting System	$910	$899	$888	$878	$867	$857
	CL	Meter Proving System	$3,182	$3,144	$3,106	$3,069	$3,032	$2,996
	CQ	Metscan	$6,580	$6,501	$6,423	$6,346	$6,270	$6,195
	CY	Land Information System	$220	$217	$215	$212	$210	$207
	DC	Instrument Recording System	$2,650	$2,618	$2,587	$2,556	$2,525	$2,495
	DH	Instrument Calibrating System	$350	$346	$342	$338	$333	$329
	DM	GIV - Graphics Information Viewer	$1,672	$1,652	$1,632	$1,613	$1,593	$1,574
	EA	EnergySense Services Management	$970	$958	$947	$935	$924	$913
	EG	ECHO Charitable Donation Database	$150	$148	$146	$145	$143	$141
	EM	DGIS	$8,172	$8,074	$7,977	$7,881	$7,787	$7,693
	ER	Cost of Service	$400	$395	$390	$386	$381	$377
	ES	Corrosion Tracking System	$100	$99	$98	$96	$95	$94
	EU	Contact Registry System	$150	$148	$146	$145	$143	$141
	EV	Capital Budget System	$100	$99	$98	$96	$95	$94
	EW	Community Investment Tracking	$100	$99	$98	$96	$95	$94
	EX	Commercial Inspections	$100	$99	$98	$96	$95	$94
	FD	Corrective Action Request	$200	$198	$195	$193	$191	$188
	GD	Construction POS (Cash Register System)	$340	$336	$332	$328	$324	$320
	GE	Hitline Database	$450	$445	$439	$434	$429	$424
	HC	Dropchute	$1,160	$1,146	$1,132	$1,119	$1,105	$1,092

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Co.	App. Code	Description	2010 - 2015 AMS Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
	HE	Fuel Cardlock System	$230	$227	$225	$222	$219	$217
	HT	Distribution Planning Project	$100	$99	$98	$96	$95	$94
	HY	Industry Dialogue Manager (IDM)	$5,172	$5,110	$5,049	$4,988	$4,928	$4,869
	HZ	Leak Analysis Management System	$500	$494	$488	$482	$476	$471
	IA	Building Management Manager	$100	$99	$98	$96	$95	$94
	IB	Natural Gas Fleet Billing (NGV Fleet)	$100	$99	$98	$96	$95	$94
	IC	Glycol Analysis	$100	$99	$98	$96	$95	$94
1 Total			**$256,430**	**$253,353**	**$250,313**	**$247,309**	**$244,341**	**$241,409**
2	7	Work Force Management - InService	$15,950	$15,759	$15,569	$15,383	$15,198	$15,016
	7	Work Force Management - Maximo	$28,602	$28,259	$27,920	$27,585	$27,254	$26,927
	10	Payroll Human Resources System	$2,300	$2,272	$2,245	$2,218	$2,192	$2,165
	11	Benefits Administration System	$2,280	$2,253	$2,226	$2,199	$2,173	$2,146
	12	Employee Biographics System	$260	$257	$254	$251	$248	$245
	13	Payroll Distribution System	$500	$494	$488	$482	$476	$471
	15	Time Entry System	$210	$207	$205	$203	$200	$198
	16	Job Costing System	$100	$99	$98	$96	$95	$94
	29	Property Tax System	$200	$198	$195	$193	$191	$188
	35	Industry Dialogue Manager (IDM)	$5,232	$5,169	$5,107	$5,046	$4,985	$4,926
	35	Load Profiling and Settlement System	$11,782	$11,641	$11,501	$11,363	$11,227	$11,092
	36	Drawing Control System	$110	$109	$107	$106	$105	$104
	37	Activity Tracking System	$2,682	$2,650	$2,618	$2,587	$2,556	$2,525
	54	GIS Web Mapping	$1,672	$1,652	$1,632	$1,613	$1,593	$1,574
	55	Load Research Data Maintenance & Analysis	$810	$800	$791	$781	$772	$763
	57	Facility Maintenance Management System (Maximo)	$6,912	$6,829	$6,747	$6,666	$6,586	$6,507
	57	FMMS - Substation Inspection System	$380	$375	$371	$366	$362	$358
	57	FMMS - Tapchart	$380	$375	$371	$366	$362	$358
	57	Remote Access to Maximo	$380	$375	$371	$366	$362	$358
	AH	TWACS / MV90	$2,432	$2,403	$2,374	$2,345	$2,317	$2,290
	AV	Safe Work Management System	$500	$494	$488	$482	$476	$471

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Co.	App. Code	Description	2010 - 2015 AMS Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
	BC	Service Interruption Reporting	$150	$148	$146	$145	$143	$141
	BM	RateExpert and DataManager (LODESTAR)	$3,122	$3,085	$3,048	$3,011	$2,975	$2,939
	CK	Managerial Reporting System	$500	$494	$488	$482	$476	$471
	CT	Maximo Cost Tracking System	$100	$99	$98	$96	$95	$94
	CX	Land and Properties Management System	$2,078	$2,053	$2,028	$2,004	$1,980	$1,956
	DA	Least Cost SCADA	$110	$109	$107	$106	$105	$104
	DB	Isolated Generation Reporting	$250	$247	$244	$241	$238	$235
	DB	Isolated Plants System	$1,238	$1,223	$1,208	$1,194	$1,180	$1,165
	DD	ION Enterprises	$1,216	$1,201	$1,187	$1,173	$1,159	$1,145
	DZ	Daily Average Pool Price on ENET	$110	$109	$107	$106	$105	$104
	EG	ECHO Charitable Donation Database	$110	$109	$107	$106	$105	$104
	FG	Business Objects Infrastructure & End-User Support	$7,988	$7,892	$7,797	$7,704	$7,611	$7,520
	FW	ATCO Electric Outage Notification (AEONS)	$1,972	$1,948	$1,925	$1,902	$1,879	$1,856
	GC	FMMS - Testform	$190	$188	$185	$183	$181	$179
	GT	ATCO Electric Geospatial Information System	$3,750	$3,705	$3,661	$3,617	$3,573	$3,530
	HB	CROW - Control RM Oper Window	$3,816	$3,770	$3,725	$3,680	$3,636	$3,592
	HC	Dropchute	$1,230	$1,215	$1,201	$1,186	$1,172	$1,158
	HN	Capital Programs Tracking	$110	$109	$107	$106	$105	$104
	IV	TRACCESS	$3,932	$3,885	$3,838	$3,792	$3,747	$3,702
2 Total			**$115,646**	**$114,258**	**$112,887**	**$111,533**	**$110,194**	**$108,872**
3	10	Payroll Human Resources System	$550	$543	$537	$530	$524	$518
	11	Benefits Administration System	$560	$553	$547	$540	$534	$527
	12	Employee Biographics System	$130	$128	$127	$125	$124	$122
	13	Payroll Distribution System	$130	$128	$127	$125	$124	$122
	15	Time Entry System	$100	$99	$98	$96	$95	$94
	16	Job Costing System	$100	$99	$98	$96	$95	$94
	70	TIS/STAR	$42,952	$42,437	$41,927	$41,424	$40,927	$40,436
	AG	Pipeline Value Inspection	$350	$346	$342	$338	$333	$329
	AW	Surface Lease Management System (SLMS)	$140	$138	$137	$135	$133	$132

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Co.	App. Code	Description	2010 - 2015 AMS Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
	AX	Standards and Quality Assurance Database	$110	$109	$107	$106	$105	$104
	CF	Daily Oil Bulletin (Nickels)	$110	$109	$107	$106	$105	$104
	CR	Metretek	$608	$601	$593	$586	$579	$572
	DY	Event Tracking System	$110	$109	$107	$106	$105	$104
	ED	Employees Participating in Communities (EPIC)	$370	$366	$361	$357	$353	$348
	ES	Corrosion Tracking System	$110	$109	$107	$106	$105	$104
	EV	Capital Budget System	$110	$109	$107	$106	$105	$104
	EY	Competency Management Info System (CMIS)	$360	$356	$351	$347	$343	$339
	FY	ACCUMAP	$900	$889	$879	$868	$858	$847
	GK	Pipeline Evaluation Program	$110	$109	$107	$106	$105	$104
	GN	Facility Operation System	$3,310	$3,270	$3,231	$3,192	$3,154	$3,116
	HJ	Alberta One Call	$350	$346	$342	$338	$333	$329
	HK	Green House Gas	$500	$494	$488	$482	$476	$471
	HM	MARS	$42,912	$42,397	$41,888	$41,386	$40,889	$40,398
	HU	TIS	$1,213	$1,198	$1,184	$1,170	$1,156	$1,142
3 Total			**$96,195**	**$95,042**	**$93,899**	**$92,771**	**$91,660**	**$90,560**

14.2 Application Disaster Recovery

Co.	App. Code	Description	2010 - 2015 Application DR Pricing (excluding COLA)					
			2010	2011	2012	2013	2014	2015
1	00	DR - Pathloss LM	$38	$38	$37	$37	$36	$36
	02	DR - 1X Network for Work Management	$1,472	$1,455	$1,437	$1,420	$1,403	$1,386
	02	DR - Work Management Phase 1	$2,820	$2,786	$2,753	$2,720	$2,687	$2,655
	02	DR - Work Management Phase 2	$1,625	$1,606	$1,586	$1,567	$1,548	$1,530
	20	DR - Khalix Database/database server only	$440	$435	$430	$424	$419	$414

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	41	DR - Landman	$22	$22	$21	$21	$21	$21
	51	DR - PC Automate	$399	$394	$389	$385	$380	$376
	66	DR - FASuite (Fleet Focus)	$558	$551	$545	$538	$532	$525
	67	DR- Daily Forecasting System (DFSS)	$2,500	$2,470	$2,440	$2,411	$2,382	$2,354
	AT	DR - SynerGee Gas Modelling LM	$75	$74	$73	$72	$71	$71
	AT	DR - SynerGee LM	$79	$78	$77	$76	$75	$74
	AV	DR - Safe Work Management System (SWMS)	$49	$48	$48	$47	$47	$46
	BL	DR - RegStattion (tables in GIV database)	$132	$130	$129	$127	$126	$124
	BW	DR - Premier Plus 4	$221	$218	$215	$213	$210	$208
	DM	DR - Graphic Image Viewer	$290	$287	$283	$280	$276	$273
	DT	DR - Gas Chromotography (EZChrom) Edm & Cgy	$297	$294	$290	$287	$283	$280
1 Total			**$11,017**	**$10,885**	**$10,754**	**$10,625**	**$10,498**	**$10,372**
2	00	DR - Pathloss LM	$38	$38	$37	$37	$36	$36
	00	DR - QuickBooks LM	$55	$54	$54	$53	$52	$52
	35	DR - Customer Choice (LPSS)	$3,042	$3,005	$2,969	$2,934	$2,898	$2,864
	35	DR - Dropchute	$1,549	$1,530	$1,512	$1,494	$1,476	$1,458
	37	DR - Activity Tracking System (ATS)	$371	$367	$362	$358	$354	$349
	55	DR - Load Research (Lodestar)	$1,588	$1,569	$1,550	$1,531	$1,513	$1,495
	57	DR - Maximo	$305	$301	$298	$294	$291	$287
	AH	DR - TWACS / MV90	$4,055	$4,006	$3,958	$3,911	$3,864	$3,817
	AV	DR - Safe Work Management System (SWMS)	$165	$163	$161	$159	$157	$155
	BC	DR - SIR for XP	$341	$337	$333	$329	$325	$321
	BM	DR - Rate Expert	$697	$689	$680	$672	$664	$656
	DZ	DR - Daily Average Pool Price on ENET	$98	$97	$96	$95	$93	$92
	FG	DR - Business Objects	$547	$540	$534	$528	$521	$515
	FN	DR - Aspen One Liner LM	$49	$48	$48	$47	$47	$46
	GT	DR - GeoMedia Pro LM	$32	$32	$31	$31	$30	$30
	GX	DR - AutoCAD LM	$49	$48	$48	$47	$47	$46
	GX	DR- AutoCAD	$55	$54	$54	$53	$52	$52
2 Total			**$13,035**	**$12,879**	**$12,725**	**$12,572**	**$12,421**	**$12,272**
3	00	DR - Pathloss LM	$38	$38	$37	$37	$36	$36
	AG	DR - SCCbd32	$38	$38	$37	$37	$36	$36

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	CR	DR - Metretek	$1,432	$1,415	$1,398	$1,381	$1,365	$1,348
	FY	DR - Accumap	$37	$37	$36	$36	$35	$35
	HU	DR - TIS	$6	$6	$6	$6	$6	$6
3 Total			**$1,552**	**$1,533**	**$1,515**	**$1,496**	**$1,478**	**$1,461**

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15 APPLICATION MANAGED SERVICE (AMS) PRICE SCHEDULE

The following tables are draft only and are based upon an estimated COLA of 3%, of which is applied to the labour component percentage (in Canadian dollars). Reference Section 5.2. Billing metric is $ per month.

15.1 General (Excluding Application Disaster Recovery)

Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 AMS Price Schedule					
				2010	2011	2012	2013	2014	2015
1	2	Work Management Phase 1 (Advantex system)	100.00%	$7,861	-	-	-	-	-
	2	Work Management Phase 2 (Stages 1 and 2)	100.00%	$80,031	-	-	-	-	-
	3	Non Gas Sales Information System	100.00%	$237	-	-	-	-	-
	4	CAD (Computer Aided Dispatch)	100.00%	$47,689	-	-	-	-	-
	10	Payroll Human Resources System	100.00%	$2,369	-	-	-	-	-
	11	Benefits Administration System	100.00%	$2,647	-	-	-	-	-
	12	Employee Biographics System	100.00%	$968	-	-	-	-	-
	13	Payroll Distribution System	100.00%	$134	-	-	-	-	-
	15	Time Entry System	100.00%	$515	-	-	-	-	-
	16	Job Costing System	100.00%	$103	-	-	-	-	-
	20	BARS/Khalix	100.00%	$1,928	-	-	-	-	-
	27	IRIS	100.00%	$34,167	-	-	-	-	-
	29	Property Tax System	100.00%	$103	-	-	-	-	-
	41	Landman	100.00%	$1,636	-	-	-	-	-
	51	PC Automate	100.00%	$1,877	-	-	-	-	-
	62	Gas Engineering (LAMS XP)	100.00%	$258	-	-	-	-	-
	66	FA Suite	100.00%	$6,028	-	-	-	-	-
	67	Daily Forecasting Settlement (DFSS)	100.00%	$32,550	-	-	-	-	-
	AG	Gas Valve Inspection (formerly Valve Inspection Tracking)	100.00%	$165	-	-	-	-	-
	AJ	TRIM Context	100.00%	$1,018	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 AMS Price Schedule					
				2010	2011	2012	2013	2014	2015
	AV	Safe Work Management System	100.00%	$361	-	-	-	-	-
	AW	Surface Lease Management System (SLMS)	100.00%	$155	-	-	-	-	-
	AX	Standards and Quality Assurance Database	100.00%	$103	-	-	-	-	-
	BL	Reg Station Inspections	100.00%	$1,638	-	-	-	-	-
	BQ	Quality Assurance Audit	100.00%	$103	-	-	-	-	-
	BT	ProjectWise	100.00%	$1,722	-	-	-	-	-
	BV	Pressure Factor Measurement System	100.00%	$185	-	-	-	-	-
	BW	PremierPlus4	100.00%	$1,722	-	-	-	-	-
	CG	Gas Odorant Tracking System	100.00%	$103	-	-	-	-	-
	CH	Natural Gas Vehicle Billing	100.00%	$464	-	-	-	-	-
	CK	Managerial Reporting System	100.00%	$937	-	-	-	-	-
	CL	Meter Proving System	100.00%	$3,277	-	-	-	-	-
	CQ	Metscan	100.00%	$6,777	-	-	-	-	-
	CY	Land Information System	100.00%	$227	-	-	-	-	-
	DC	Instrument Recording System	100.00%	$2,730	-	-	-	-	-
	DH	Instrument Calibrating System	100.00%	$361	-	-	-	-	-
	DM	GIV - Graphics Information Viewer	100.00%	$1,722	-	-	-	-	-
	EA	EnergySense Services Management	100.00%	$999	-	-	-	-	-
	EG	ECHO Charitable Donation Database	100.00%	$155	-	-	-	-	-
	EM	DGIS	100.00%	$8,417	-	-	-	-	-
	ER	Cost of Service	100.00%	$412	-	-	-	-	-
	ES	Corrosion Tracking System	100.00%	$103	-	-	-	-	-
	EU	Contact Registry System	100.00%	$155	-	-	-	-	-
	EV	Capital Budget System	100.00%	$103	-	-	-	-	-
	EW	Community Investment Tracking	100.00%	$103	-	-	-	-	-
	EX	Commercial Inspections	100.00%	$103	-	-	-	-	-
	FD	Corrective Action Request	100.00%	$206	-	-	-	-	-
	GD	Construction POS (Cash Register System)	100.00%	$350	-	-	-	-	-
	GE	Hitline Database	100.00%	$464	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 AMS Price Schedule					
				2010	2011	2012	2013	2014	2015
	HC	Dropchute	100.00%	$1,195	-	-	-	-	-
	HE	Fuel Cardlock System	100.00%	$237	-	-	-	-	-
	HT	Distribution Planning Project	100.00%	$103	-	-	-	-	-
	HY	Industry Dialogue Manager (IDM)	100.00%	$5,327	-	-	-	-	-
	HZ	Leak Analysis Management System	100.00%	$515	-	-	-	-	-
	IA	Building Management Manager	100.00%	$103	-	-	-	-	-
	IB	Natural Gas Fleet Billing (NGV Fleet)	100.00%	$103	-	-	-	-	-
	IC	Glycol Analysis	100.00%	$103	-	-	-	-	-
1 Total				**$264,123**	-	-	-	-	-
2	7	Work Force Management - InService	100.00%	$16,429	-	-	-	-	-
	7	Work Force Management - Maximo	100.00%	$29,460	-	-	-	-	-
	10	Payroll Human Resources System	100.00%	$2,369	-	-	-	-	-
	11	Benefits Administration System	100.00%	$2,348	-	-	-	-	-
	12	Employee Biographics System	100.00%	$268	-	-	-	-	-
	13	Payroll Distribution System	100.00%	$515	-	-	-	-	-
	15	Time Entry System	100.00%	$216	-	-	-	-	-
	16	Job Costing System	100.00%	$103	-	-	-	-	-
	29	Property Tax System	100.00%	$206	-	-	-	-	-
	35	Industry Dialogue Manager (IDM)	100.00%	$5,389	-	-	-	-	-
		Load Profiling and Settlement System	100.00%	$12,135	-	-	-	-	-
	36	Drawing Control System	100.00%	$113	-	-	-	-	-
	37	Activity Tracking System	100.00%	$2,762	-	-	-	-	-
	54	GIS Web Mapping	100.00%	$1,722	-	-	-	-	-
	55	Load Research Data Maintenance & Analysis	100.00%	$834	-	-	-	-	-
	57	Facility Maintenance Management System (Maximo)	100.00%	$7,119	-	-	-	-	-
	57	FMMS - Substation Inspection System	100.00%	$391	-	-	-	-	-
	57	FMMS - Tapchart	100.00%	$391	-	-	-	-	-
	57	Remote Access to Maximo	100.00%	$391	-	-	-	-	-
	AH	TWACS / MV90	100.00%	$2,505	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 AMS Price Schedule					
				2010	2011	2012	2013	2014	2015
	AV	Safe Work Management System	100.00%	$515	-	-	-	-	-
	BC	Service Interruption Reporting	100.00%	$155	-	-	-	-	-
	BM	RateExpert and DataManager (LODESTAR)	100.00%	$3,216	-	-	-	-	-
	CK	Managerial Reporting System	100.00%	$515	-	-	-	-	-
	CT	Maximo Cost Tracking System	100.00%	$103	-	-	-	-	-
	CX	Land and Properties Management System	100.00%	$2,140	-	-	-	-	-
	DA	Least Cost SCADA	100.00%	$113	-	-	-	-	-
	DB	Isolated Generation Reporting	100.00%	$258	-	-	-	-	-
	DB	Isolated Plants System	100.00%	$1,275	-	-	-	-	-
	DD	ION Enterprises	100.00%	$1,252	-	-	-	-	-
	DZ	Daily Average Pool Price on ENET	100.00%	$113	-	-	-	-	-
	EG	ECHO Charitable Donation Database	100.00%	$113	-	-	-	-	-
	FG	Business Objects Infrastructure & End-User Support	100.00%	$8,228	-	-	-	-	-
	FW	ATCO Electric Outage Notification (AEONS)	100.00%	$2,031	-	-	-	-	-
	GC	FMMS - Testform	100.00%	$196	-	-	-	-	-
	GT	ATCO Electric Geospatial Information System	100.00%	$3,863	-	-	-	-	-
	HB	CROW - Control RM Oper Window	100.00%	$3,930	-	-	-	-	-
	HC	Dropchute	100.00%	$1,267	-	-	-	-	-
	HN	Capital Programs Tracking	100.00%	$113	-	-	-	-	-
	IV	TRACCESS	100.00%	$4,050	-	-	-	-	-
2 Total				**$119,115**	-	-	-	-	-
3	10	Payroll Human Resources System	100.00%	$567	-	-	-	-	-
	11	Benefits Administration System	100.00%	$577	-	-	-	-	-
	12	Employee Biographics System	100.00%	$134	-	-	-	-	-
	13	Payroll Distribution System	100.00%	$134	-	-	-	-	-
	15	Time Entry System	100.00%	$103	-	-	-	-	-
	16	Job Costing System	100.00%	$103	-	-	-	-	-
	70	TIS/STAR	100.00%	$44,241	-	-	-	-	-
	AG	Pipeline Value Inspection	100.00%	$361	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 AMS Price Schedule					
				2010	2011	2012	2013	2014	2015
	AW	Surface Lease Management System (SLMS)	100.00%	$144	-	-	-	-	-
	AX	Standards and Quality Assurance Database	100.00%	$113	-	-	-	-	-
	CF	Daily Oil Bulletin (Nickels)	100.00%	$113	-	-	-	-	-
	CR	Metretek	100.00%	$626	-	-	-	-	-
	DY	Event Tracking System	100.00%	$113	-	-	-	-	-
	ED	Employees Participating in Communities (EPIC)	100.00%	$381	-	-	-	-	-
	ES	Corrosion Tracking System	100.00%	$113	-	-	-	-	-
	EV	Capital Budget System	100.00%	$113	-	-	-	-	-
	EY	Competency Management Info System (CMIS)	100.00%	$371	-	-	-	-	-
	FY	ACCUMAP	100.00%	$927	-	-	-	-	-
	GK	Pipeline Evaluation Program	100.00%	$113	-	-	-	-	-
	GN	Facility Operation System	100.00%	$3,409	-	-	-	-	-
	HJ	Alberta One Call	100.00%	$361	-	-	-	-	-
	HK	Green House Gas	100.00%	$515	-	-	-	-	-
	HM	MARS	100.00%	$44,199	-	-	-	-	-
	HU	TIS	100.00%	$1,249	-	-	-	-	-
3 Total				**$99,081**	-	-	-	-	-

15.2 Application Disaster Recovery

Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 Application DR Price Schedule					
				2010	2011	2012	2013	2014	2015
1	00	DR - Pathloss LM	90.00%	$39	-	-	-	-	-
	02	DR - 1X Network for Work Management	75.00%	$1,506	-	-	-	-	-
	02	DR - Work Management Phase 1	75.00%	$2,883	-	-	-	-	-
	02	DR - Work Management Phase 2	75.00%	$1,662	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 Application DR Price Schedule					
				2010	2011	2012	2013	2014	2015
	20	DR - Khalix Database/database server only	90.00%	$452	-	-	-	-	-
	41	DR - Landman	90.00%	$23	-	-	-	-	-
	51	DR - PC Automate	90.00%	$410	-	-	-	-	-
	66	DR - FASuite (Fleet Focus)	90.00%	$573	-	-	-	-	-
	67	DR- Daily Forecasting System (DFSS)	75.00%	$2,556	-	-	-	-	-
	AT	DR - SynerGee Gas Modelling LM	90.00%	$77	-	-	-	-	-
	AT	DR - SynerGee LM	90.00%	$81	-	-	-	-	-
	AV	DR - Safe Work Management System (SWMS)	90.00%	$50	-	-	-	-	-
	BL	DR - RegStattion (tables in GIV database)	90.00%	$136	-	-	-	-	-
	BW	DR - Premier Plus 4	90.00%	$226	-	-	-	-	-
	DM	DR - Graphic Image Viewer	90.00%	$298	-	-	-	-	-
	DT	DR - Gas Chromotography (EZChrom) Edm & Cgy	75.00%	$304	-	-	-	-	-
1 Total				**$11,275**	-	-	-	-	-
2	00	DR - Pathloss LM	90.00%	$39	-	-	-	-	-
	00	DR - QuickBooks LM	90.00%	$56	-	-	-	-	-
	35	DR - Customer Choice (LPSS)	75.00%	$3,110	-	-	-	-	-
	35	DR - Dropchute	75.00%	$1,584	-	-	-	-	-
	37	DR - Activity Tracking System (ATS)	90.00%	$381	-	-	-	-	-
	55	DR - Load Research (Lodestar)	75.00%	$1,624	-	-	-	-	-
	57	DR - Maximo	90.00%	$313	-	-	-	-	-
	AH	DR - TWACS / MV90	75.00%	$4,146	-	-	-	-	-
	AV	DR - Safe Work Management System (SWMS)	90.00%	$169	-	-	-	-	-
	BC	DR - SIR for XP	90.00%	$350	-	-	-	-	-
	BM	DR - Rate Expert	90.00%	$716					
	DZ	DR - Daily Average Pool Price on ENET	90.00%	$101	-	-	-	-	-
	FG	DR - Business Objects	90.00%	$562	-	-	-	-	-
	FN	DR - Aspen One Liner LM	90.00%	$50	-	-	-	-	-
	GT	DR - GeoMedia Pro LM	90.00%	$33	-	-	-	-	-
	GX	DR - AutoCAD LM	90.00%	$50	-	-	-	-	-

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Co.	App. Code	Description	Lab. Comp. %	2010 - 2015 Application DR Price Schedule					
				2010	2011	2012	2013	2014	2015
	GX	DR- AutoCAD	90.00%	$56	-	-	-	-	-
2 Total				**$13,341**	-	-	-	-	-
3	00	DR - Pathloss LM	90.00%	$39	-	-	-	-	-
	AG	DR - SCCbd32	90.00%	$39					
	CR	DR - Metretek	75.00%	$1,465					
	FY	DR - Accumap	90.00%	$38	-	-	-	-	-
	HU	DR - TIS	90.00%	$6	-	-	-	-	-
3 Total				**$1,587**	-	-	-	-	-

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16 PRICING

The following table is to demonstrate base level pricing during the term of the contract (in 2009 Canadian dollars).

Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
3 Express Request Service								
D.3	Express Request service Fee	Per Item / Request	$58.00	$58.00	$58.00	$58.00	$58.00	$58.00
4 Application Service Provider Service								
D.4.1.1	Discoverer License Purchase	Named User license fee / One Time	$729.36	$729.36	$729.36	$729.36	$729.36	$729.36
D.4.1.1	Discoverer Maint. on License Purchase	Named User license fee / Month	$13.37	$13.37	$13.37	$13.37	$13.37	$13.37
D.4.1.1	Discrete Mfg Read License Purchase	Named User license fee / One Time	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00
D.4.1.1	Discrete Mfg Read Maint. on Lic. Purcha	Named User license fee / Month	$19.10	$19.10	$19.10	$19.10	$19.10	$19.10
D.4.1.1	Discrete Mfg Update License Purchase	Named User license fee / One Time	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30
D.4.1.1	Discrete Mfg Update Maint. on Lic Purch	Named User license fee / Month	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
D.4.1.1	Enterprise Asset Mgmt Lic. Purchase	Named User license fee / One Time	$2,675.80	$2,675.80	$2,675.80	$2,675.80	$2,675.80	$2,675.80

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.4.1.1	Enterprise Asset Mgmt Maint on Lic Purch	Named User license fee / Month	$49.10	$49.10	$49.10	$49.10	$49.10	$49.10
D.4.1.1	Financials Read License Purchase	Named User license fee / One Time	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00
D.4.1.1	Financials Read Maint. on License Purch	Named User license fee / Month	$19.10	$19.10	$19.10	$19.10	$19.10	$19.10
D.4.1.1	Financials Update License Purchase	Named User license fee / One Time	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30
D.4.1.1	Financials Update Maint. on Lic Purchase	Named User license fee/ Month	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
D.4.1.1	iExpense License Purchase	Per Expense Report / One Time	$3.90	$3.90	$3.90	$3.90	$3.90	$3.90
D.4.1.1	iExpense Maintenance on License Purchase	Per Expense Report / Month	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
D.4.1.1	iProcurement License Purchase	Per Procurement Line / One Time	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00
D.4.1.1	iProcurement Maintenance on Lic Purchase	Per Procurement Line / Month	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89
D.4.1.1	Mobile Supply Chain License Purchase	Named User license fee / One Time	$1,088.40	$1,088.40	$1,088.40	$1,088.40	$1,088.40	$1,088.40

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.4.1.1	Mobile Supply Chain Maint on Lic Purchas	Per Named User / Month	$19.95	$19.95	$19.95	$19.95	$19.95	$19.95
D.4.1.1	Order Management License Purchase	Per Order Line / One Time	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
D.4.1.1	Order Management Maint on Lic. Purchase	Per Order Line / Month	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
D.4.1.1	Project Acct Read License Purchase	Named User license fee / One Time	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00
D.4.1.1	Project Acct Read Maint. on Lic Purchase	Per Named User / Month	$19.10	$19.10	$19.10	$19.10	$19.10	$19.10
D.4.1.1	Project Acct Update License Purchase	Named User license fee / One Time	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30
D.4.1.1	Project Acct Update Maint. on Lic Purchase	Per Named User / Month	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
D.4.1.1	Project Billing License Purchase	Named User license fee / One Time	$2,180.50	$2,180.50	$2,180.50	$2,180.50	$2,180.50	$2,180.50
D.4.1.1	Project Billing Maint. on Lic Purchase	Per Named User / Month	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
D.4.1.1	Project Management License Purchase	Named User license fee / One Time	$578.80	$578.80	$578.80	$578.80	$578.80	$578.80
D.4.1.1	Project Management Maint on Lic Purchase	Per Named User / Month	$10.60	$10.60	$10.60	$10.60	$10.60	$10.60
D.4.1.1	Purchasing Read License Purchase	Named User license fee / One Time	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00	$1,044.00

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.4.1.1	Purchasing Read Maint. on Lic Purchase	Per Named User / Month	$19.10	$19.10	$19.10	$19.10	$19.10	$19.10
D.4.1.1	Purchasing Update License Purchase	Named User license fee/ One Time	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30	$2,728.30
D.4.1.1	Purchasing Update Maint. on Lic Purchase	Per Named User / Month	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
5 Distributed Server and Managed Service								
D.5.1	Distributed Server Hosting - Windows Tier 1	Per Environment / Month	$68.95	$67.92	$66.90	$65.90	$64.91	$63.94
D.5.1	Distributed Server Hosting - Windows Tier 2	Per Environment / Month	$147.75	$145.53	$143.35	$141.20	$139.08	$136.99
D.5.1	Distributed Server Hosting - Windows Tier 3	Per Environment / Month	$295.50	$291.07	$286.70	$282.40	$278.16	$273.99
D.5.1	Distributed Server Hosting - Windows Tier 4	Per Environment / Month	$581.15	$572.43	$563.84	$555.38	$547.05	$538.84
D.5.1	Distributed Server Hosting - Windows Tier 5	Per Environment / Month	$886.50	$873.20	$860.10	$847.20	$834.49	$821.97
D.5.1	Distributed Server Hosting - Unix Tier 1	Per Environment / Month	$226.55	$223.15	$219.80	$216.50	$213.25	$210.05
D.5.1	Distributed Server Hosting - Unix Tier 2	Per Environment / Month	$453.10	$446.30	$439.61	$433.02	$426.52	$420.12

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.5.1	Distributed Server Hosting - Unix Tier 3	Per Environment / Month	$728.90	$717.97	$707.20	$696.59	$686.14	$675.85
D.5.1	Distributed Server Hosting - Unix Tier 4	Per Environment / Month	$1,822.25	$1,794.92	$1,768.00	$1,741.48	$1,715.36	$1,689.63
D.5.1	Distributed Server Hosting - Unix Tier 5	Per Environment / Month	$3,644.50	$3,589.83	$3,535.98	$3,482.94	$3,430.70	$3,379.24
D.5.1	Distributed Server Support - Windows Bronze	Per Environment / Month	$210.00	$207.48	$204.99	$202.53	$200.10	$197.70
D.5.1	Distributed Server Support - Windows Silver	Per Environment / Month	$560.00	$553.28	$546.64	$540.08	$533.60	$527.20
D.5.1	Distributed Server Support - Windows Gold	Per Environment / Month	$1,120.00	$1,106.56	$1,093.28	$1,080.16	$1,067.20	$1,054.39
D.5.1	Distributed Server Support - Windows Platinum	Per Environment / Month	$1,680.00	$1,659.84	$1,639.92	$1,620.24	$1,600.80	$1,581.59
D.5.1	Distributed Server Support - Unix Bronze	Per Environment / Month	$350.00	$345.80	$341.65	$337.55	$333.50	$329.50
D.5.1	Distributed Server Support - Unix Silver	Per Environment / Month	$690.00	$681.72	$673.54	$665.46	$657.47	$649.58
D.5.1	Distributed Server Support - Unix Gold	Per Environment / Month	$1,250.00	$1,235.00	$1,220.18	$1,205.54	$1,191.07	$1,176.78

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.5.1	Distributed Server Support - Unix Platinum	Per Environment / Month	$1,930.00	$1,906.84	$1,883.96	$1,861.35	$1,839.01	$1,816.94
D.5.1	Shared Database Licensing - Oracle Standard Tier 1	Per Environment / Month	$125.00	$125.00	$125.00	$125.00	$125.00	$125.00
D.5.1	Shared Database Licensing - Oracle Standard Tier 2	Per Environment / Month	$250.00	$250.00	$250.00	$250.00	$250.00	$250.00
D.5.1	Shared Database Licensing - Oracle Standard Tier 3	Per Environment / Month	$400.00	$400.00	$400.00	$400.00	$400.00	$400.00
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 1	Per Environment / Month	$330.00	$330.00	$330.00	$330.00	$330.00	$330.00
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 2	Per Environment / Month	$660.00	$660.00	$660.00	$660.00	$660.00	$660.00
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 3	Per Environment / Month	$1,060.00	$1,060.00	$1,060.00	$1,060.00	$1,060.00	$1,060.00
D.5.1	Shared Database Licensing - Microsoft SQL Tier 2	Per Environment / Month	$35.00	$35.00	$35.00	$35.00	$35.00	$35.00
D.5.1	Shared Database Licensing - Microsoft SQL Tier 3	Per Environment / Month	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00
D.5.1	Dedicated Oracle Standard Database Licensing - Named User	Per Named User / Month	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50
D.5.1	Dedicated Oracle Standard Database Licensing - CPU	Per Oracle CPU / Month	$330.00	$330.00	$330.00	$330.00	$330.00	$330.00

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.5.1	Dedicated Oracle Enterprise Database Licensing - Named User	Per Named User / Month	$17.50	$17.50	$17.50	$17.50	$17.50	$17.50
D.5.1	Dedicated Oracle Enterprise Database Licensing - CPU	Per Oracle CPU / Month	$880.00	$880.00	$880.00	$880.00	$880.00	$880.00
D.5.1	Dedicated Microsoft SQL Standard Database Licensing- CPU	Per SQL CPU / Month	$135.00	$135.00	$135.00	$135.00	$135.00	$135.00
D.5.4	Web Hosting	Per Website / Month	$ 105.40	$103.82	$102.26	$100.73	$99.22	$97.73
D.5.5	Secure Site WEB Hosting	Per Website / Month	$ 164.50	$162.03	$159.60	$157.21	$154.85	$152.53
D.5.6	File Transfer	Per Website / Month	$ 73.88	$72.77	$71.68	$70.60	$69.54	$68.50
D.5.7	Sharepoint Site Setup Fee	Per Website / One Time	$287.50	$284.05	$280.64	$277.27	$273.94	$270.65
D.5.7	Sharepoint	Per Website / Month	$ 123.13	$121.28	$119.46	$117.67	$115.90	$114.16
6 Mainframe Service								
D.6.2.2	ADABAS CPU Minutes (EOL)	Per CPU Minute Used / Month	$7.27	EOL	EOL	EOL	EOL	EOL
D.6.2.3	Non-IMS/ADABAS Batch CPU Minutes	Per CPU Minute Used / Month	$6.19	$6.07	$5.95	$5.84	$5.73	$5.62
D.6.2.4	IMS/ADABAS Batch CPU Minutes (EOL)	Per CPU Minute Used / Month	$7.27	EOL	EOL	EOL	EOL	EOL
D.6.2.5	CICS CPU Minutes	Per CPU Minute Used / Month	$5.77	$5.65	$5.53	$5.41	$5.30	$5.19

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.6.2.6	DB2 CPU Minutes	Per CPU Minute Used / Month	$5.77	$5.65	$5.53	$5.41	$5.30	$5.19
D.6.2.7	IMS CPU Minutes (EOL)	Per CPU Minute Used / Month	$6.19	EOL	EOL	EOL	EOL	EOL
D.6.2.8	TSO CPU Minutes	Per CPU Minute Used / Month	$5.77	$5.65	$5.53	$5.41	$5.30	$5.19
D.6.2.9	Oracle CPU Minutes	Per CPU Minute Used / Month	$5.77	$5.65	$5.53	$5.41	$5.30	$5.19
D.6.3.1 D 6.3.2 D 6.3.3	Print Forms / 1000	Per 1000 Pages printed	Specified Expense	Specified Expense	Specified Expense	Specified Expense	Specified Expense	Specified Expense
D.6.3.4	Print Pages	Per 1000 Pages printed	$41.97	$42.60	$43.24	$43.89	$44.55	$45.22
D.6.4	Mainframe Print Configuration	Per Printer Setup / One Time	$10.70	$10.50	$10.30	$10.10	$9.91	$9.72
7 Disaster Recovery Service								
D.7.1	Distributed Infrastructure - DR	Per UID / Month	$15.66	$15.43	$15.20	$14.97	$14.75	$14.53
8 Project Labour Service								
D.8.1	Administrator	Per Hour	$66.00	$65.44	$64.88	$64.33	$63.78	$63.24
D.8.1	Analyst 1	Per Hour	$90.00	$89.24	$88.48	$87.73	$86.98	$86.24
D.8.1	Analyst 2	Per Hour	$111.00	$110.06	$109.12	$108.19	$107.27	$106.36
D.8.1	Analyst 3	Per Hour	$137.00	$135.84	$134.69	$133.55	$132.41	$131.28
D.8.1	Analyst 4	Per Hour	$152.00	$150.71	$149.43	$148.16	$146.90	$145.65
D.8.1	Consultant	Per Hour	$198.00	$196.32	$194.65	$193.00	$191.36	$189.73

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.8.1	Senior Consultant	Per Hour	$264.00	$261.76	$259.54	$257.33	$255.14	$252.97
D.8.1	Project Manager	Per Hour	$204.00	$202.27	$200.55	$198.85	$197.16	$195.48
D.8.1	Senior Engagement Manager	Per Hour	$293.00	$290.51	$288.04	$285.59	$283.16	$280.75
D 8.2	Hardware Install / Move / Add / Change	Per Hour	$111.30	$110.35	$109.41	$108.48	$107.56	$106.65
D.8.3	Software Support Labour	Per Hour	$111.30	$110.35	$109.41	$108.48	$107.56	$106.65
9 Storage Service								
D.9.1	Long Term Archive - 1st Mth	Per GB / 1st Month	$2.80	$2.80	$2.80	$2.80	$2.80	$2.80
D.9.2	Long Term Archive	Per GB / Month	$0.49	$0.42	$0.36	$0.31	$0.26	$0.22
D.9.3	Dist App Storage Local Disk	Per GB / Month	$4.56	$4.01	$3.53	$3.11	$2.74	$2.41
D.9.4	Dist App Storage Network Attached Disk	Per GB / Month	$13.04	$11.48	$10.10	$8.89	$7.82	$6.88
D.9.5	Oracle Fin. Storage - LOCAL	Per GB / Month	$4.56	$4.01	$3.53	$3.11	$2.74	$2.41
D.9.6	Oracle Fin. Storage - DASD	Per GB / Month	$13.04	$11.48	$10.10	$8.89	$7.82	$6.88
D.9.7	Website Storage Disk	Per GB / Month	$13.04	$11.48	$10.10	$8.89	$7.82	$6.88
D.9.8	Distributed Archive Tape (EOL)	Per GB / Month	$2.80	EOL	EOL	EOL	EOL	EOL
D.9.9	Distributed Archive Tape Retrieval (EOL)	Per GB / Month	$38.00	EOL	EOL	EOL	EOL	EOL
D.9.10.2	Mainframe DASD	Per GB / Month	$5.24	$4.61	$4.06	$3.57	$3.14	$2.76
D.9.10.3	Mainframe Tape	Per GB / Month	$0.34	$0.29	$0.25	$0.21	$0.18	$0.15
D.9.10.4	Tape HSM	Per GB / Month	$0.15	$0.13	$0.11	$0.09	$0.08	$0.07

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.9.11	File Server Storage	Per GB / Month	$14.48	$12.74	$11.21	$9.86	$8.68	$7.64
D.9.12	Email Storage (50mb blocks)	Per 50MB / UID / Month	$1.15	$0.98	$0.83	$0.71	$0.60	$0.51
10 User Connectivity Service								
D.10.1	User ID	Per UID / Month	$17.43	$17.22	$17.01	$16.81	$16.61	$16.41
D.10.2	User ID w/limited ATCO Domain usage	Per UID / Month	$11.13	$11.00	$10.87	$10.74	$10.61	$10.48
D.10.3	Confidential Request	Per Request	T & M	T & M	T & M	T & M	T & M	T & M
D.10.4	Internet Access	Per UID / Month	$21.48	$21.16	$20.84	$20.53	$20.22	$19.92
D.10.5	Instant Messaging	Per UID / Month	$5.00	$4.93	$4.86	$4.79	$4.72	$4.65
D.10.6	Web File	Per UID / Month	$6.00	$5.91	$5.82	$5.73	$5.64	$5.56
D.10.7	Web Access Management	Per UID / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.10.8	VPN - Remote Client	Per Fob / Month	$32.31	$31.83	$31.36	$30.89	$30.43	$29.98
D.10.8	VPN-Remote Client w/ split tunnelling	Per Fob / Month	$41.67	$41.04	$40.42	$39.81	$39.21	$38.62
D.10.9	SSL Secure Remote Access	Per Fob / Month	$32.31	$31.83	$31.36	$30.89	$30.43	$29.98
D.10.10	Citrix Terminal Server	Per UID / Month	$40.97	$40.35	$39.74	$39.14	$38.55	$37.97
D.10.11	Data Recovery	Per Request	T & M	T & M	T & M	T & M	T & M	T & M
D.10.12	RightFax	Per UID / Month	$20.98	$20.67	$20.36	$20.06	$19.76	$19.47
11 Network Connectivity Service								

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.11.1	Server Load Balancing	Per Load Balancing Server Port/ Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.11.2	VPN - Remote Branch	Per Connection / Month	$778.64	$766.96	$755.46	$744.13	$732.97	$721.98
D.11.2	VPN Remote Branch Onsite Spare	Per Spare Device / Month	$103.82	$102.26	$100.73	$99.22	$97.73	$96.26
D.11.3	VPN - Small Offices	Per Connection / Month	$140.56	$138.45	$136.37	$134.32	$132.31	$130.33
D.11.4	Terminal Server 1 Port	Per Teminal Server Device / Month	$116.77	$115.02	$113.29	$111.59	$109.92	$108.27
D.11.4	Terminal Server 4 Port	Per Teminal Server Device / Month	$155.69	$153.35	$151.05	$148.78	$146.55	$144.35
D.11.4	Terminal Server 8 Port	Per Teminal Server Device / Month	$186.83	$184.03	$181.27	$178.55	$175.87	$173.23
D.11.4	Terminal Server 20 Port	Per Teminal Server Device / Month	$233.54	$230.04	$226.59	$223.19	$219.84	$216.54
D.11.5	ADSL Light	Per Connection / Month	$1,125.00	$1,108.13	$1,091.51	$1,075.14	$1,059.01	$1,043.12

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.11.5	ADSL Light Carrier Component	Usage per Circuit / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.11.6	ADSL Unlimited	Per Connection / Month	$1,294.00	$1,274.59	$1,255.47	$1,236.64	$1,218.09	$1,199.82
D.11.6	ADSL Unlimited Carrier Component	Usage per Circuit / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.11.7	Network Connectivity	Per Port / Month	$27.90	$27.48	$27.07	$26.66	$26.26	$25.87
D.11.7	Xerox Network Connectivity	Per Port / Month	$27.90	$27.48	$27.07	$26.66	$26.26	$25.87
D.11.8	Network Telecom Fee	One Time	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.11.9	Blackberry	Per Blackberry / Month	$30.00	$29.55	$29.11	$28.67	$28.24	$27.82
D.11.10	Shared Blackberry	Per UID / Month	$9.00	$8.87	$8.74	$8.61	$8.48	$8.35
D.11.11	Mobile Information - Base/Database	Per UID / Month	$27.00	$26.60	$26.20	$25.81	$25.42	$25.04
D.11.11	Mobile Information - Base/Inclusive	Per UID / Month	$32.00	$31.52	$31.05	$30.58	$30.12	$29.67
D.11.11	Mobile Info - Base/Messenger/Responder	Per UID / Month	$21.00	$20.69	$20.38	$20.07	$19.77	$19.47
D.11.12	ISDN Circuit	Per Circuit / Month	$81.69	$80.46	$79.25	$78.06	$76.89	$75.74
D.11.13	External Web Conference	Per UID / Month	$44.23	$43.57	$42.92	$42.28	$41.65	$41.03
D.11.14	Video Conferencing	Per Circuit / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.11.14	Video Conferencing Lease w/ Support	Per System / Month	$609.22	$600.08	$591.08	$582.21	$573.48	$564.88
D.11.14	Video Conferencing Support	Per Support Package / Month	$245.00	$242.06	$239.16	$236.29	$233.45	$230.65
D.11.14	Video Conference Set + 2 Mics	Per System / Month	$41.37	$40.75	$40.14	$39.54	$38.95	$38.37
D.11.14	Video Conference Set + 1 Mic	Per System / Month	$38.12	$37.55	$36.99	$36.44	$35.89	$35.35
D.11.15.2	56k Virtual WAN	Per Connection / Month	$1,447.92	$1,426.20	$1,404.81	$1,383.74	$1,362.98	$1,342.54
D.11.15.3	112k Virtual WAN	Per Connection / Month	$2,220.58	$2,187.27	$2,154.46	$2,122.14	$2,090.31	$2,058.96
D.11.15.4	256k Virtual WAN	Per Connection / Month	$1,845.46	$1,817.78	$1,790.51	$1,763.65	$1,737.20	$1,711.14
D.11.15.5	384k Virtual WAN	Per Connection / Month	$3,122.25	$3,075.42	$3,029.29	$2,983.85	$2,939.09	$2,895.00
D.11.15.6	512k Virtual WAN	Per Connection / Month	$2,283.92	$2,249.66	$2,215.92	$2,182.68	$2,149.94	$2,117.69
D.11.15.7	768k Virtual WAN	Per Connection / Month	$3,573.68	$3,520.07	$3,467.27	$3,415.26	$3,364.03	$3,313.57
D.11.15.8	1.5M Virtual WAN	Per Connection / Month	$4,127.05	$4,065.14	$4,004.16	$3,944.10	$3,884.94	$3,826.67

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.11.16	Remote Office WAN Acceleration - Sm Site	Per Wan Accelerator / Month	$501.17	$493.65	$486.25	$478.96	$471.78	$464.70
D.11.16	Remote Office WAN Acceleration - Lg Site	Per Wan Accelerator / Month	$795.09	$783.16	$771.41	$759.84	$748.44	$737.21
D.11.17	Ethernet LAN Ext - 100Mb WAN	Per Connection / Month	$4,387.49	$4,321.68	$4,256.85	$4,193.00	$4,130.11	$4,068.16
D.11.17	Ethernet LAN Ext - 10Mb Local 3 Yr	Per Connection / Month	$2,225.00	$2,191.63	$2,158.76	$2,126.38	$2,094.48	$2,063.06
D.11.17	Ethernet LAN Ext - Remote	Per Connection / Month	$2,375.00	$2,339.38	$2,304.29	$2,269.73	$2,235.68	$2,202.14
D.11.17	Ethernet LAN Ext - Wireless	Per Connection / Month	$2,108.49	$2,076.86	$2,045.71	$2,015.02	$1,984.79	$1,955.02
D.11.18	4 Wire Loop	Per Connection / Month	$1,250.00	$1,231.25	$1,212.78	$1,194.59	$1,176.67	$1,159.02
D.11.18	4 Wire Loop High Speed	Per Connection / Month	$1,524.09	$1,501.23	$1,478.71	$1,456.53	$1,434.68	$1,413.16
D.11.19	Mobility Aircard	Per Aircard / Month	$79.00	$77.82	$76.65	$75.50	$74.37	$73.25
D.11.20	Mobility Aircard Data	Usage / Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based
D.11.21	Mobility Aircard Airtime	Usage / Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.11.22	Firewall	Per Firewall / Month	$349.10	$343.86	$338.70	$333.62	$328.62	$323.69
D.11.23	Firewall - Medium Office	Per Firewall / Month	$1,353.39	$1,333.09	$1,313.09	$1,293.39	$1,273.99	$1,254.88
D.11.24	Firewall I380 w/8 Port Unlimited License	Per Firewall / Month	$2,070.08	$2,039.03	$2,008.44	$1,978.31	$1,948.64	$1,919.41
D.11.25	Intrusion Detection – Small Office	Per IDS Device / Month	$1,944.39	$1,915.22	$1,886.49	$1,858.19	$1,830.32	$1,802.87
D.11.26	Intrusion Detection – Medium Office	Per IDS Device / Month	$4,136.21	$4,074.17	$4,013.06	$3,952.86	$3,893.57	$3,835.17
D.11.27	Megastream and other Dedicated	Per Connection / Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based
D.11.28	Modem Line	Per Line / Month	$28.50	$28.07	$27.65	$27.24	$26.83	$26.43
D.11.29	Load Limited Meeting Room Switch - Daily	Per Switch / Day	$12.00	$11.82	$11.64	$11.47	$11.30	$11.13
D.11.29	Load Limited Meeting Room Switch - Monthly	Per Switch / Month	$92.80	$91.41	$90.04	$88.69	$87.36	$86.05
D.11.30	Office Performance Mtg Rm Switch - Daily	Per Switch / Day	$23.00	$22.66	$22.32	$21.99	$21.66	$21.34
D.11.30	Office Performance Meeting Room Switch - Monthly	Per Switch / Month	$178.40	$175.72	$173.08	$170.48	$167.92	$165.40
D.11.31	Internet ISP Connectivity - Daily	Per Port / Day	$7.00	$6.90	$6.80	$6.70	$6.60	$6.50
D.11.31	Internet ISP Connectivity - Weekly	Per Port / Day	$20.00	$19.70	$19.40	$19.11	$18.82	$18.54
D.11.31	Internet ISP Connectivity - Monthly	Per Port / Day	$35.10	$34.57	$34.05	$33.54	$33.04	$32.54

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
12 Voice Service								
D.12.2	Centrex Telephone	Per Set / Month	$22.59	$22.25	$21.91	$21.58	$21.25	$20.93
D.12.3	Call Centre Auto Attendant Applications	Per Appication / Month	$3.15	$3.10	$3.05	$3.00	$2.96	$2.92
D.12.4	Call Centre Auto Attendant Ports	Per Auto Attendant Port / Month	$84.32	$83.06	$81.82	$80.60	$79.40	$78.21
D.12.5	Call Centre Readerboard	Per Readerboard / Month	$1,099.95	$1,083.45	$1,067.20	$1,051.19	$1,035.42	$1,019.89
D.12.6	Voice Call Centre Set Charges	Per Set / Month	$25.02	$24.74	$24.46	$24.19	$23.92	$23.65
D.12.7	Call Centre Application	Per Call Center System / Month	$15,401.76	$15,170.73	$14,943.17	$14,719.02	$14,498.23	$14,280.76
D.12.8	Call Centre Server	Per Call Center System / Month	$2,072.05	$2,040.97	$2,010.36	$1,980.20	$1,950.50	$1,921.24
D.12.9	Call Centre Trunking	Per Call Center Trunk / Month	$85.70	$84.41	$83.14	$81.89	$80.66	$79.45
D.12.10	Custom Music-On-Hold	Per Set / Month	$2.36	$2.32	$2.28	$2.24	$2.20	$2.16
D.12.11	Dedicated Off Premise Extension	Per Extension / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.12.12	Dedicated Tie Lines	Per Tie Line / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.13	Recorded Announcement	Per Recorded Announcement License / Month	$7.82	$7.70	$7.58	$7.46	$7.35	$7.24
D.12.14	Recorded Announcement Route	Per Recorded Announcement Route Subscription / Month	$35.04	$34.51	$33.99	$33.48	$32.98	$32.49
D.12.15	Remote Centre Voice Network Access	Per Remote Network Access Circuit / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.16	Telecom Circuit Fees	Per Telecom Circuit Fee / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.17	Voice Line Charges	Per Line / Month	$28.50	$28.07	$27.65	$27.24	$26.83	$26.43
D.12.18	Voice AIN Auto Activation Fee	Per AIN Circuit / Month	$3.00	$2.95	$2.90	$2.85	$2.80	$2.75
D.12.19	Voice AIN Redirect Line Charge	Per AIN Circuit / Month	$12.49	$12.30	$12.11	$11.93	$11.75	$11.57
D.12.20	Voice Feature - Line Appearance	Per Line Appearance / Set / Month	$1.88	$1.85	$1.82	$1.79	$1.76	$1.73

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.12.21	Voice Feature - Voice Mail Basic	Per Voice Mail Box / Month	$7.43	$7.32	$7.21	$7.10	$7.00	$6.90
D.12.21	Voice Feature -VM Extra Time (10min inc.)	Per Extra Time Increments / Voice Mailbox / Month	$6.80	$6.70	$6.60	$6.50	$6.40	$6.31
D.12.22	Voice Feature - Voice Mail Desktop	Per Voice Mail Desktop Application / Voice Mailbox / Month	$4.00	$3.94	$3.88	$3.82	$3.76	$3.70
D.12.23	Voice Feature - Voice Mail Fax	Per Fax Activation / Voice Mailbox / Month	$13.40	$13.20	$13.00	$12.81	$12.62	$12.43
D.12.24	Voice Feature - Voice Mail Remote Notify	Per Remote Notification Activation / Voice Mailbox / Month	$3.00	$2.95	$2.90	$2.85	$2.80	$2.75
D.12.25	Voice Install, Move, Add, Change	Per Item / Request	$65.10	$64.32	$63.55	$62.79	$62.04	$61.30

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.12.26	Long Distance Direct	Usage Per Long Distance Minute / Month	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027
D.12.27	Voice Set Charges	Per Set / Month	$13.52	$13.32	$13.12	$12.93	$12.74	$12.55
D.12.28	Voice Feature - Call Park	Per Call Park Feature / Set / Month	$1.88	$1.85	$1.82	$1.79	$1.76	$1.73
D.12.29	Voice Feature - Call Recording	Per Call Recording Port / Month	$75.00	$73.88	$72.77	$71.68	$70.60	$69.54
D.12.30	Voice Feature - Call Recording Archive	Per Call Recording Port / Month	$9.03	$8.89	$8.75	$8.61	$8.48	$8.35
D.12.31	Voice Set Feature - SC Manager	Per Speed Call List Managed / Set / Month	$1.88	$1.85	$1.82	$1.79	$1.76	$1.73
D.12.32	Voice Set Feature - SC User	Per Speed Call List Used / Set / Month	$0.94	$0.93	$0.92	$0.91	$0.90	$0.89
D.12.33	Voice Set Feature - Visual Call Waiting	Per Set / Month	$0.94	$0.93	$0.92	$0.91	$0.90	$0.89
D.12.34	Voice Telecom Fee	One Time	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.35	Mobility Data	Usage / Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based
D.12.36	Cordless Telephone Set Charge	Per Set / Month	$25.91	$25.52	$25.14	$24.76	$24.39	$24.02

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.12.37	Wireless Cellular	Per Cellular / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.38	Wireless Pager	Per Pager / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.39	Audio Conference Set Charge	Per Set / Month	$34.38	$33.86	$33.35	$32.85	$32.36	$31.87
D.12.40	Audio Conference Port Fee	Per Port / Month	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.41	Audio Conference Cancellation Fee	One Time	Service Based	Service Based	Service Based	Service Based	Service Based	Service Based
D.12.42	PBX Trunk Port	Per Trunk Port / Month	$161.24	$158.82	$156.44	$154.09	$151.78	$149.50
D.12.43	Remote Call Centre Base	Per System / Month	$403.16	$397.11	$391.15	$385.28	$379.50	$373.81
13 Workstation Service								
D.13.2	PC H/W Operating Lease	Per PC / Month	$66.74	$65.41	$64.11	$62.83	$61.58	$60.35
D.13.3	PC H/W Oper. Lease-High Performance	Per PC / Month	$119.02	$116.64	$114.31	$112.02	$109.78	$107.58
D.13.4	PC Support Low	Per PC / Month	$109.30	$107.99	$106.69	$105.41	$104.15	$102.90
D.13.4	PC Support Medium	Per PC / Month	$112.60	$111.25	$109.92	$108.60	$107.30	$106.01
D.13.4	PC Support High	Per PC / Month	$132.00	$130.42	$128.85	$127.30	$125.77	$124.26
D.13.5	Laptop H/W Operating Lease	Per PC / Month	$118.92	$116.54	$114.21	$111.93	$109.69	$107.50
D.13.6	Ruggedized Laptop - Enhanced	Per PC / Month	$188.18	$184.42	$180.73	$177.12	$173.58	$170.11
D.13.6	Ruggedized Laptop - Standard	Per PC / Month	$135.80	$133.08	$130.42	$127.81	$125.25	$122.75

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.13.7	Laptop H/W Slim Operating Lease	Per PC / Month	$138.90	$136.12	$133.40	$130.73	$128.12	$125.56
D.13.8	Laptop Support Low	Per PC / Month	$127.70	$126.17	$124.66	$123.16	$121.68	$120.22
D.13.8	Laptop Support Medium	Per PC / Month	$131.80	$130.22	$128.66	$127.12	$125.59	$124.08
D.13.8	Laptop Support High	Per PC / Month	$164.50	$162.53	$160.58	$158.65	$156.75	$154.87
D.13.9	Hard Drive Encryption	Per PC / Month	$5.50	$5.50	$5.50	$5.50	$5.50	$5.50
D.13.10	Monitor LCD - 17 inch (EOL)	Per Monitor / Month	$19.96	$18.96	EOL	EOL	EOL	EOL
D.13.10	Monitor LCD - 19 inch	Per Monitor / Month	$22.17	$21.06	$20.01	$19.01	$18.06	$17.16
D.13.10	Monitor LCD - 20 inch	Per Monitor / Month	$24.38	$23.16	$22.00	$20.90	$19.86	$18.87
D.13.10	Monitor LCD – 24 inch	Per Monitor / Month	$28.15	$26.74	$25.40	$24.13	$22.92	$21.77
D.13.10	Monitor LCD – 27 inch	Per Monitor / Month	$32.48	$30.86	$29.32	$27.85	$26.46	$25.14
D.13.10	Monitor LCD – 30 inch	Per Monitor / Month	$34.41	$32.69	$31.06	$29.51	$28.03	$26.63
D.13.11	Monitor CRT - 17 inch (EOL)	Per Monitor / Month	$7.77	EOL	EOL	EOL	EOL	EOL
D.13.11	Monitor CRT - 21 inch (EOL)	Per Monitor / Month	$12.36	EOL	EOL	EOL	EOL	EOL
D.13.12	Software Integration /Pkging Labour	Per Hour	$111.30	$111.30	$111.30	$111.30	$111.30	$111.30
D.13.13	Software Distribution Fee	Per Distribution	$166.90	$166.90	$166.90	$166.90	$166.90	$166.90
D.13.14	B & W Printer Low Volume	Per Printer / Month	$30.72	$29.80	$28.91	$28.04	$27.20	$26.38

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.13.14	B & W Printer Medium Volume	Per Printer / Month	$40.32	$39.11	$37.94	$36.80	$35.70	$34.63
D.13.14	B & W Printer High Volume	Per Printer / Month	$116.93	$113.42	$110.02	$106.72	$103.52	$100.41
D.13.14	Colour Printer Low Volume	Per Printer / Month	$35.23	$34.17	$33.14	$32.15	$31.19	$30.25
D.13.14	Colour Printer Medium Volume	Per Printer / Month	$44.45	$43.12	$41.83	$40.58	$39.36	$38.18
D.13.14	Colour Printer High Volume	Per Printer / Month	$64.13	$62.21	$60.35	$58.54	$56.79	$55.09
D.13.14	Colour Printer Maximum Volume	Per Printer / Month	$106.94	$103.73	$100.62	$97.60	$94.67	$91.83
D.13.15	Printer Support Low Volume	Per Printer / Month	$34.20	$33.79	$33.38	$32.98	$32.58	$32.19
D.13.15	Printer Support Medium Volume	Per Printer / Month	$67.50	$66.69	$65.89	$65.10	$64.32	$63.55
D.13.15	Printer Support High Volume	Per Printer / Month	$115.40	$114.02	$112.65	$111.30	$109.96	$108.64
D.13.16	Xerox Lease	Per Xerox Device / Month	Device Based	Device Based	Device Based	Device Based	Device Based	Device Based
D.13.17	Xerox service	Per Impression / Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based
D.13.18	Xerox Printer Support	Per Xerox Device / Month	$67.50	$67.50	$67.50	$67.50	$67.50	$67.50
D.13.18	High Volume Xerox Printer Support	Per Xerox Device / Month	$115.40	$115.40	$115.40	$115.40	$115.40	$115.40

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Schedule Reference	Service Description	2010 – 2015 Pricing (excluding COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
D.13.19	Xerox Consumables	Per Consumable	Usage based	Usage based	Usage based	Usage based	Usage based	Usage based
D.13.20	Printer Toner / Ink	Per Toner/Ink	Usage based	Usage based	Usage based	Usage based	Usage based	Usage based
D.13.21	Workstation Install/Move/Add/Chg	Per Item / Request	$133.30	$131.70	$130.12	$128.56	$127.02	$125.50

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17 PRICE SCHEDULE

The following table is draft only and is based upon an estimated COLA of 3%, of which is applied to the labour component percentage (in Canadian dollars).

Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
3 Express Request Service									
D.3	Express Request service Fee	Per Item / Request	100.00%	$59.74	-	-	-	-	-
4 Application Service Provider Service									
D.4.1.1	Discoverer License Purchase	Named User license fee / One Time	0.00%	$729.36	-	-	-	-	-
D.4.1.1	Discoverer Maint. on License Purchase	Named User license fee / Month	0.00%	$13.37	-	-	-	-	-
D.4.1.1	Discrete Mfg Read License Purchase	Named User license fee / One Time	0.00%	$1,044.00	-	-	-	-	-
D.4.1.1	Discrete Mfg Read Maint. on Lic. Purcha	Named User license fee / Month	0.00%	$19.10	-	-	-	-	-
D.4.1.1	Discrete Mfg Update License Purchase	Named User license fee / One Time	0.00%	$2,728.30	-	-	-	-	-
D.4.1.1	Discrete Mfg Update Maint. on Lic Purch	Named User license fee / Month	0.00%	$50.00	-	-	-	-	-
D.4.1.1	Enterprise Asset Mgmt Lic. Purchase	Named User license fee / One Time	0.00%	$2,675.80	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.4.1.1	Enterprise Asset Mgmt Maint on Lic Purch	Named User license fee / Month	0.00%	$49.10	-	-	-	-	-
D.4.1.1	Financials Read License Purchase	Named User license fee / One Time	0.00%	$1,044.00	-	-	-	-	-
D.4.1.1	Financials Read Maint. on License Purchase	Named User license fee / Month	0.00%	$19.10	-	-	-	-	-
D.4.1.1	Financials Update License Purchase	Named User license fee / One Time	0.00%	$2,728.30	-	-	-	-	-
D.4.1.1	Financials Update Maint. on Lic Purchase	Named User license fee/ Month	0.00%	$50.00	-	-	-	-	-
D.4.1.1	iExpense License Purchase	Per Expense Report / One Time	0.00%	$3.90	-	-	-	-	-
D.4.1.1	iExpense Maintenance on License Purchase	Per Expense Report / Month	0.00%	$0.85	-	-	-	-	-
D.4.1.1	iProcurement License Purchase	Per Procurement Line / One Time	0.00%	$4.00	-	-	-	-	-
D.4.1.1	iProcurement Maintenance on Lic Purchase	Per Procurement Line / Month	0.00%	$0.89	-	-	-	-	-
D.4.1.1	Mobile Supply Chain License Purchase	Named User license fee / One Time	0.00%	$1,088.40	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.4.1.1	Mobile Supply Chain Maint on Lic Purchas	Per Named User / Month	0.00%	$19.95	-	-	-	-	-
D.4.1.1	Order Management License Purchase	Per Order Line / One Time	0.00%	$0.20	-	-	-	-	-
D.4.1.1	Order Management Maint on Lic. Purchase	Per Order Line / Month	0.00%	$0.04	-	-	-	-	-
D.4.1.1	Project Acct Read License Purchase	Named User license fee / One Time	0.00%	$1,044.00	-	-	-	-	-
D.4.1.1	Project Acct Read Maint. on Lic Purchase	Per Named User / Month	0.00%	$19.10	-	-	-	-	-
D.4.1.1	Project Acct Update License Purchase	Named User license fee / One Time	0.00%	$2,728.30	-	-	-	-	-
D.4.1.1	Project Acct Update Maint. on Lic Purchase	Per Named User / Month	0.00%	$50.00	-	-	-	-	-
D.4.1.1	Project Billing License Purchase	Named User license fee / One Time	0.00%	$2,180.50	-	-	-	-	-
D.4.1.1	Project Billing Maint. on Lic Purchase	Per Named User / Month	0.00%	$40.00	-	-	-	-	-
D.4.1.1	Project Management License Purchase	Named User license fee / One Time	0.00%	$578.80	-	-	-	-	-
D.4.1.1	Project Management Maint on Lic Purchase	Per Named User / Month	0.00%	$10.60	-	-	-	-	-
D.4.1.1	Purchasing Read License Purchase	Named User license fee / One Time	0.00%	$1,044.00	-	-	-	-	-
D.4.1.1	Purchasing Read Maint. on Lic Purchase	Per Named User / Month	0.00%	$19.10	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.4.1.1	Purchasing Update License Purchase	Named User license fee/ One Time	0.00%	$2,728.30	-	-	-	-	-
D.4.1.1	Purchasing Update Maint. on Lic Purchase	Per Named User / Month	0.00%	$50.00	-	-	-	-	-
5 Distributed Server and Managed Service									
D.5.1	Distributed Server Hosting - Windows Tier 1	Per Environment / Month	0.00%	$68.95	-	-	-	-	-
D.5.1	Distributed Server Hosting - Windows Tier 2	Per Environment / Month	0.00%	$147.75	-	-	-	-	-
D.5.1	Distributed Server Hosting - Windows Tier 3	Per Environment / Month	0.00%	$295.50	-	-	-	-	-
D.5.1	Distributed Server Hosting - Windows Tier 4	Per Environment / Month	0.00%	$581.15	-	-	-	-	-
D.5.1	Distributed Server Hosting - Windows Tier 5	Per Environment / Month	0.00%	$886.50	-	-	-	-	-
D.5.1	Distributed Server Hosting - Unix Tier 1	Per Environment / Month	0.00%	$226.55	-	-	-	-	-
D.5.1	Distributed Server Hosting - Unix Tier 2	Per Environment / Month	0.00%	$453.10	-	-	-	-	-
D.5.1	Distributed Server Hosting - Unix Tier 3	Per Environment / Month	0.00%	$728.90	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.5.1	Distributed Server Hosting - Unix Tier 4	Per Environment / Month	0.00%	$1,822.25	-	-	-	-	-
D.5.1	Distributed Server Hosting - Unix Tier 5	Per Environment / Month	0.00%	$3,644.50	-	-	-	-	-
D.5.1	Distributed Server Support - Windows Bronze	Per Environment / Month	100.00%	$216.30	-	-	-	-	-
D.5.1	Distributed Server Support - Windows Silver	Per Environment / Month	100.00%	$576.80	-	-	-	-	-
D.5.1	Distributed Server Support - Windows Gold	Per Environment / Month	100.00%	$1,153.60	-	-	-	-	-
D.5.1	Distributed Server Support - Windows Platinum	Per Environment / Month	100.00%	$1,730.40	-	-	-	-	-
D.5.1	Distributed Server Support - Unix Bronze	Per Environment / Month	100.00%	$360.50	-	-	-	-	-
D.5.1	Distributed Server Support - Unix Silver	Per Environment / Month	100.00%	$710.70	-	-	-	-	-
D.5.1	Distributed Server Support - Unix Gold	Per Environment / Month	100.00%	$1,287.50	-	-	-	-	-
D.5.1	Distributed Server Support - Unix Platinum	Per Environment / Month	100.00%	$1,987.90	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.5.1	Shared Database Licensing - Oracle Standard Tier 1	Per Environment / Month	0.00%	$125.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Oracle Standard Tier 2	Per Environment / Month	0.00%	$250.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Oracle Standard Tier 3	Per Environment / Month	0.00%	$400.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 1	Per Environment / Month	0.00%	$330.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 2	Per Environment / Month	0.00%	$660.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 3	Per Environment / Month	0.00%	$1,060.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Microsoft SQL Tier 2	Per Environment / Month	0.00%	$35.00	-	-	-	-	-
D.5.1	Shared Database Licensing - Microsoft SQL Tier 3	Per Environment / Month	0.00%	$70.00	-	-	-	-	-
D.5.1	Dedicated Oracle Standard Database Licensing - Named User	Per Named User / Month	0.00%	$6.50	-	-	-	-	-
D.5.1	Dedicated Oracle Standard Database Licensing - CPU	Per Oracle CPU / Month	0.00%	$330.00	-	-	-	-	-
D.5.1	Dedicated Oracle Enterprise Database Licensing - Named User	Per Named User / Month	0.00%	$17.50	-	-	-	-	-
D.5.1	Dedicated Oracle Enterprise Database Licensing - CPU	Per Oracle CPU / Month	0.00%	$880.00	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.5.1	Dedicated Microsoft SQL Standard Database Licensing - CPU	Per SQL CPU / Month	0.00%	$135.00	-	-	-	-	-
D.5.4	Web Hosting	Per Website / Month	40.00%	$106.66	-	-	-	-	-
D.5.5	Secure Site WEB Hosting	Per Website / Month	40.00%	$166.47	-	-	-	-	-
D.5.6	File Transfer	Per Website / Month	40.00%	$74.77	-	-	-	-	-
D.5.7	Sharepoint Site Setup Fee	Per Website / One Time	100.00%	$296.13	-	-	-	-	-
D.5.7	Sharepoint	Per Website / Month	40.00%	$124.61	-	-	-	-	-
6. Mainframe Service									
D.6.2.2	ADABAS CPU Minutes (EOL)	Per CPU Minute Used / Month	35.00%	$7.35	-	-	-	-	-
D.6.2.3	Non-IMS/ADABAS Batch CPU Minutes	Per CPU Minute Used / Month	35.00%	$6.25	-	-	-	-	-
D.6.2.4	IMS/ADABAS Batch CPU Minutes (EOL)	Per CPU Minute Used / Month	35.00%	$7.35	-	-	-	-	-
D.6.2.5	CICS CPU Minutes	Per CPU Minute Used / Month	35.00%	$5.83	-	-	-	-	-
D.6.2.6	DB2 CPU Minutes	Per CPU Minute Used / Month	35.00%	$5.83	-	-	-	-	-
D.6.2.7	IMS CPU Minutes (EOL)	Per CPU Minute Used / Month	35.00%	$6.25	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.6.2.8	TSO CPU Minutes	Per CPU Minute Used / Month	35.00%	$5.83	-	-	-	-	-
D.6.2.9	Oracle CPU Minutes	Per CPU Minute Used / Month	35.00%	$5.83	-	-	-	-	-
D.6.3.1 D 6.3.2 D 6.3.3	Print Forms / 1000	Per 1000 Pages printed	0.00%	Specified Expense			-	-	-
D.6.3.4	Print Pages	Per 1000 Pages printed	35.00%	$42.41	-	-	-	-	-
D.6.5	Mainframe Print Configuration	Per Printer Setup / One Time	0.00%	$10.70	-	-	-	-	-
7 Disaster Recovery Service									
D.7.1	Distributed Infrastructure - DR	Per UID / Month	30.00%	$15.80	-	-	-	-	-
8 Project Labour Service									
D.8.1	Administrator	Per Hour	100.00%	$67.98	-	-	-	-	-
D.8.1	Analyst 1	Per Hour	100.00%	$92.70	-	-	-	-	-
D.8.1	Analyst 2	Per Hour	100.00%	$114.33	-	-	-	-	-
D.8.1	Analyst 3	Per Hour	100.00%	$141.11	-	-	-	-	-
D.8.1	Analyst 4	Per Hour	100.00%	$156.56	-	-	-	-	-
D.8.1	Consultant	Per Hour	100.00%	$203.94	-	-	-	-	-
D.8.1	Senior Consultant	Per Hour	100.00%	$271.92	-	-	-	-	-
D.8.1	Project Manager	Per Hour	100.00%	$210.12	-	-	-	-	-
D.8.1	Senior Engagement Manager	Per Hour	100.00%	$301.79	-	-	-	-	-
D 8.2	Hardware Install / Move / Add / Change	Per Hour	100.00%	$114.64	-	-	-	-	-
D.8.3	Software Support Labour	Per Hour	100.00%	$114.64	-	-	-	-	-
9 Storage Service									

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.9.1	Long Term Archive - 1st Mth	Per GB / 1st Month	10.00%	$2.81	-	-	-	-	-
D.9.2	Long Term Archive	Per GB / Month	10.00%	$0.49	-	-	-	-	-
D.9.3	Dist App Storage Local Disk	Per GB / Month	10.00%	$4.57	-	-	-	-	-
D.9.4	Dist App Storage Network Attached Disk	Per GB / Month	10.00%	$13.08	-	-	-	-	-
D.9.5	Oracle Fin. Storage - LOCAL	Per GB / Month	10.00%	$4.57	-	-	-	-	-
D.9.6	Oracle Fin. Storage - DASD	Per GB / Month	10.00%	$13.08	-	-	-	-	-
D.9.7	Website Storage Disk	Per GB / Month	10.00%	$13.08	-	-	-	-	-
D.9.8	Distributed Archive Tape (EOL)	Per GB / Month	10.00%	$2.81	-	-	-	-	-
D.9.9	Distributed Archive Tape Retrieval (EOL)	Per GB / Month	10.00%	$38.11	-	-	-	-	-
D.9.10.2	Mainframe DASD	Per GB / Month	10.00%	$5.26	-	-	-	-	-
D.9.10.3	Mainframe Tape	Per GB / Month	10.00%	$0.34	-	-	-	-	-
D.9.10.4	Tape HSM	Per GB / Month	10.00%	$0.15	-	-	-	-	-
D.9.11	File Server Storage	Per GB / Month	10.00%	$14.52	-	-	-	-	-
D.9.12	Email Storage 50mb blocks)	Per 50MB / UID / Month	10.00%	$1.15	-	-	-	-	-
10 User Connectivity Service									
D.10.1	User ID	Per UID / Month	100.00%	$17.95	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.10.2	User ID w/limited ATCO Domain usage	Per UID / Month	100.00%	$11.46	-	-	-	-	-
D.10.3	Confidential Request	Per Request	100.00%	T & M	-	-	-	-	-
D.10.4	Internet Access	Per UID / Month	35.00%	$21.71	-	-	-	-	-
D.10.5	Instant Messaging	Per UID / Month	30.00%	$5.05	-	-	-	-	-
D.10.6	Web File Service	Per UID / Month	30.00%	$6.05	-	-	-	-	-
D.10.7	Web Access Management	Per UID / Month	30.00%	Service Based	-	-	-	-	-
D.10.8	VPN - Remote Client	Per Fob / Month	0.00%	$32.31	-	-	-	-	-
D.10.8	VPN-Remote Client w/ split tunnelling	Per Fob / Month	0.00%	$41.67	-	-	-	-	-
D.10.9	SSL Secure Remote Access	Per Fob / Month	0.00%	$32.31	-	-	-	-	-
D.10.10	Citrix Terminal Server	Per UID / Month	30.00%	$41.34	-	-	-	-	-
D.10.11	Data Recovery	Per Request	100.0%	T & M	-	-	-	-	-
D.10.12	RightFax	Per UID / Month	30.00%	$21.17	-	-	-	-	-
11 Network Connectivity Service									
D.11.1	Server Load Balancing	Per Load Balancing Server Port/ Month	35.00%	Usage Based	-	-	-	-	-
D.11.2	VPN - Remote Branch	Per Connection / Month	35.00%	$786.82	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.11.2	VPN Remote Branch Onsite Spare	Per Spare Device / Month	35.00%	$104.91	-	-	-	-	-
D.11.3	VPN - Small Offices	Per Connection / Month	35.00%	$142.04	-	-	-	-	-
D.11.4	Terminal Server 1 Port	Per Teminal Server Device / Month	35.00%	$118.00	-	-	-	-	-
D.11.4	Terminal Server 4 Port	Per Teminal Server Device / Month	35.00%	$157.32	-	-	-	-	-
D.11.4	Terminal Server 8 Port	Per Teminal Server Device / Month	35.00%	$188.79	-	-	-	-	-
D.11.4	Terminal Server 20 Port	Per Teminal Server Device / Month	35.00%	$235.99	-	-	-	-	-
D.11.5	ADSL Light	Per Connection / Month	35.00%	$1,136.81	-	-	-	-	-
D.11.5	ADSL Light Carrier Component	Usage per Circuit / Month	0.00%	Service Based	-	-	-	-	-
D.11.6	ADSL Unlimited	Per Connection / Month	35.00%	$1,307.59	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.11.6	ADSL Unlimited Carrier Component	Usage per Circuit / Month	0.00%	Service Based	-	-	-	-	-
D.11.7	Network Connectivity	Per Port / Month	35.00%	$28.19	-	-	-	-	-
D.11.7	Xerox Network Connectivity	Per Port / Month	35.00%	$28.19	-	-	-	-	-
D.11.8	Network Telecom Fee	One Time	35.00%	Service Based					
D.11.9	Blackberry	Per Blackberry / Month	30.00%	$30.27	-	-	-	-	-
D.11.10	Shared Blackberry	Per UID / Month	30.00%	$9.08	-	-	-	-	-
D.11.11	Mobile Information - Base/Database	Per UID / Month	30.00%	$27.24	-	-	-	-	-
D.11.11	Mobile Information - Base/Inclusive	Per UID / Month	30.00%	$32.29	-	-	-	-	-
D.11.11	Mobile Info - Base/Messenger/Responder	Per UID / Month	30.00%	$21.19	-	-	-	-	-
D.11.12	ISDN Circuit	Per Circuit / Month	35.00%	$82.55	-	-	-	-	-
D.11.13	External Web Conference	Per UID / Month	35.00%	$44.69	-	-	-	-	-
D.11.14	Video Conferencing	Per Circuit / Month	35.00%	Service Based	-	-	-	-	-
D.11.14	Video Conferencing Lease w/ Support	Per System / Month	35.00%	$615.62	-	-	-	-	-
D.11.14	Video Conferencing Support	Per Support Package / Month	100.00%	$252.35	-	-	-	-	-
D.11.14	Video Conference Set + 2 Mics	Per System / Month	35.00%	$41.80	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.11.14	Video Conference Set + 1 Mic	Per System / Month	35.00%	$38.52	-	-	-	-	-
D.11.15.2	56k Virtual WAN	Per Connection / Month	35.00%	$1,463.12	-	-	-	-	-
D.11.15.3	112k Virtual WAN	Per Connection / Month	35.00%	$2,243.90	-	-	-	-	-
D.11.15.4	256k Virtual WAN	Per Connection / Month	35.00%	$1,864.84	-	-	-	-	-
D.11.15.5	384k Virtual WAN	Per Connection / Month	35.00%	$3,155.03	-	-	-	-	-
D.11.15.6	512k Virtual WAN	Per Connection / Month	35.00%	$2,307.90	-	-	-	-	-
D.11.15.7	768k Virtual WAN	Per Connection / Month	35.00%	$3,611.20	-	-	-	-	-
D.11.15.8	1.5M Virtual WAN	Per Connection / Month	35.00%	$4,170.38	-	-	-	-	-
D.11.16	Remote Office WAN Acceleration - Sm Site	Per Wan Accelerator / Month	35.00%	$506.43	-	-	-	-	-
D.11.16	Remote Office WAN Acceleration - Lg Site	Per Wan Accelerator / Month	35.00%	$803.44	-	-	-	-	-
D.11.17	Ethernet LAN Ext - 100Mb WAN	Per Connection / Month	35.00%	$4,433.56	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.11.17	Ethernet LAN Ext - 10Mb Local 3 Yr	Per Connection / Month	35.00%	$2,248.36	-	-	-	-	-
D.11.17	Ethernet LAN Ext - Remote	Per Connection / Month	35.00%	$2,399.94	-	-	-	-	-
D.11.17	Ethernet LAN Ext - Wireless	Per Connection / Month	35.00%	$2,130.63	-	-	-	-	-
D.11.18	4 Wire Loop	Per Connection / Month	35.00%	$1,263.13	-	-	-	-	-
D.11.18	4 Wire Loop High Speed	Per Connection / Month	35.00%	$1,540.09	-	-	-	-	-
D.11.19	Mobility Aircard	Per Aircard / Month	35.00%	$79.83	-	-	-	-	-
D.11.20	Mobility Aircard Data	Usage / Month	0.00%	Usage Based	-	-	-	-	-
D.11.21	Mobility Aircard Airtime	Usage / Month	0.00%	Usage Based	-	-	-	-	-
D.11.22	Firewall	Per Firewall / Month	35.00%	$352.77	-	-	-	-	-
D.11.23	Firewall - Medium Office	Per Firewall / Month	35.00%	$1,367.60	-	-	-	-	-
D.11.24	Firewall I380 w/8 Port Unlimited License	Per Firewall / Month	35.00%	$2,091.82	-	-	-	-	-
D.11.25	Intrusion Detection – Small Office	Per IDS Device / Month	35.00%	$1,964.81	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.11.26	Intrusion Detection – Medium Office	Per IDS Device / Month	35.00%	$4,179.64	-	-	-	-	-
D.11.27	Megastream and other Dedicated	Per Connection / Month	35.00%	Service Based	-	-	-	-	-
D.11.28	Modem Line	Per Line / Month	35.00%	$28.80	-	-	-	-	-
D.11.29	Load Limited Meeting Room Switch - Daily	Per Switch / Day	35.00%	$12.13	-	-	-	-	-
D.11.29	Load Limited Meeting Room Switch - Monthly	Per Switch / Month	35.00%	$93.77	-	-	-	-	-
D.11.30	Office Performance Mtg Rm Switch - Daily	Per Switch / Day	35.00%	$23.24	-	-	-	-	-
D.11.30	Office Performance Meeting Room Switch - Monthly	Per Switch / Month	35.00%	$180.27	-	-	-	-	-
D.11.31	Internet ISP Connectivity - Daily	Per Port / Day	35.00%	$7.07	-	-	-	-	-
D.11.31	Internet ISP Connectivity - Weekly	Per Port / Day	35.00%	$20.21	-	-	-	-	-
D.11.31	Internet ISP Connectivity - Monthly	Per Port / Day	35.00%	$35.47	-	-	-	-	-
12 Voice Service									
D.12.2	Centrex Telephone	Per Set / Month	35.00%	$22.83	-	-	-	-	-
D.12.3	Call Centre Auto Attendant Applications	Per Appication / Month	35.00%	$3.18	-	-	-	-	-
D.12.4	Call Centre Auto Attendant Ports	Per Auto Attendant Port / Month	35.00%	$85.21	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.12.5	Call Centre Readerboard	Per Readerboard / Month	35.00%	$1,111.50	-	-	-	-	-
D.12.6	Voice Call Centre Set Charges	Per Set / Month	35.00%	$25.28	-	-	-	-	-
D.12.7	Call Centre Application	Per Call Center System / Month	35.00%	$15,563.48	-	-	-	-	-
D.12.8	Call Centre Server	Per Call Center System / Month	35.00%	$2,093.81	-	-	-	-	-
D.12.9	Call Centre Trunking	Per Call Center Trunk / Month	35.00%	$86.60	-	-	-	-	-
D.12.10	Custom Music-On-Hold	Per Set / Month	35.00%	$2.38	-	-	-	-	-
D.12.11	Dedicated Off Premise Extension	Per Extension / Month	35.00%	Service Based	-	-	-	-	-
D.12.12	Dedicated Tie Lines	Per Tie Line / Month	0.00%	Service Based	-	-	-	-	-
D.12.13	Recorded Announcement	Per Recorded Announcement License / Month	35.00%	$7.90	-	-	-	-	-
D.12.14	Recorded Announcement Route	Per Recorded Announcement Route Subscription / Month	35.00%	$35.41	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.12.15	Remote Centre Voice Network Access	Per Remote Network Access Circuit / Month	35.00%	Service Based	-	-	-	-	-
D.12.16	Telecom Circuit Fees	Per Telecom Circuit Fee / Month	0.00%	Service Based	-	-	-	-	-
D.12.17	Voice Line Charges	Per Line / Month	35.00%	$28.80	-	-	-	-	-
D.12.18	Voice AIN Auto Activation Fee	Per AIN Circuit / Month	35.00%	$3.03	-	-	-	-	-
D.12.19	Voice AIN Redirect Line Charge	Per AIN Circuit / Month	35.00%	$12.62	-	-	-	-	-
D.12.20	Voice Feature - Line Appearance	Per Line Appearance / Set / Month	35.00%	$1.90	-	-	-	-	-
D.12.21	Voice Feature - Voice Mail Basic	Per Voice Mail Box / Month	35.00%	$7.51	-	-	-	-	-
D.12.21	Voice Feature -VM Extra Time (10min inc.)	Per Extra Time Increments / Voice Mailbox / Month	35.00%	$6.87	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.12.22	Voice Feature - Voice Mail Desktop	Per Voice Mail Desktop Application / Voice Mailbox / Month	35.00%	$4.04	-	-	-	-	-
D.12.23	Voice Feature - Voice Mail Fax	Per Fax Activation / Voice Mailbox / Month	35.00%	$13.54	-	-	-	-	-
D.12.24	Voice Feature - Voice Mail Remote Notify	Per Remote Notification Activation / Voice Mailbox / Month	35.00%	$3.03	-	-	-	-	-
D.12.25	Voice Install, Move, Add, Change	Per Item / Request	100.00%	$67.05	-	-	-	-	-
D.12.26	Long Distance Direct	Usage Per Long Distance Minute / Month	35.00%	$0.03	-	-	-	-	-
D.12.27	Voice Set Charges	Per Set / Month	35.00%	$13.66	-	-	-	-	-
D.12.28	Voice Feature - Call Park	Per Call Park Feature / Set / Month	35.00%	$1.90	-	-	-	-	-
D.12.29	Voice Feature - Call Recording	Per Call Recording Port / Month	35.00%	$75.79	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.12.30	Voice Feature - Call Recording Archive	Per Call Recording Port / Month	35.00%	$9.12	-	-	-	-	-
D.12.31	Voice Set Feature - SC Manager	Per Speed Call List Managed / Set / Month	35.00%	$1.90	-	-	-	-	-
D.12.32	Voice Set Feature - SC User	Per Speed Call List Used / Set / Month	35.00%	$0.95	-	-	-	-	-
D.12.33	Voice Set Feature - Visual Call Waiting	Per Set / Month	35.00%	$0.95	-	-	-	-	-
D.12.34	Voice Telecom Fee	One Time	0.00%	Service Based	-	-	-	-	-
D.12.35	Cordless Telephone Set Charge	Per Set / Month	35.00%	$26.18	-	-	-	-	-
D.12.36	Audio Conference Set Charge	Per Set / Month	35.00%	$34.74	-	-	-	-	-
D.12.37	Audio Conference Port Fee	Per Port / Month	35.00%	Service Based	-	-	-	-	-
D.12.38	Audio Conference Cancellation Fee	One Time	35.00%	Service Based	-	-	-	-	-
D.12.39	PBX Trunk Port	Per Trunk Port / Month	35.00%	$162.93	-	-	-	-	-
D.12.40	Remote Call Centre Base	Per System / Month	35.00%	$407.39	-	-	-	-	-
13 Workstation Service									
D.13.2	PC H/W Operating Lease	Per PC / Month	0.00%	$66.74	-	-	-	-	-
D.13.3	PC H/W Oper. Lease-High Performance	Per PC / Month	0.00%	$119.02	-	-	-	-	-
D.13.4	PC Support Low	Per PC / Month	100.00%	$112.58	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.13.4	PC Support Medium	Per PC / Month	100.00%	$115.98	-	-	-	-	-
D.13.4	PC Support High	Per PC / Month	100.00%	$135.96	-	-	-	-	-
D.13.5	Laptop H/W Operating Lease	Per PC / Month	0.00%	$118.92	-	-	-	-	-
D.13.6	Ruggedized Laptop - Enhanced	Per PC / Month	0.00%	$188.18	-	-	-	-	-
D.13.6	Ruggedized Laptop - Standard	Per PC / Month	0.00%	$135.80	-	-	-	-	-
D.13.7	Laptop H/W Slim Operating Lease	Per PC / Month	0.00%	$138.90	-	-	-	-	-
D.13.8	Laptop Support Low	Per PC / Month	100.00%	$131.53	-	-	-	-	-
D.13.8	Laptop Support Medium	Per PC / Month	100.00%	$135.75	-	-	-	-	-
D.13.8	Laptop Support High	Per PC / Month	100.00%	$169.44	-	-	-	-	-
D.13.9	Hard Drive Encryption	Per PC / Month	0.00%	$5.50	-	-	-	-	-
D.13.10	Monitor LCD - 17 inch (EOL)	Per Monitor / Month	0.00%	$19.96	-	-	-	-	-
D.13.10	Monitor LCD - 19 inch	Per Monitor / Month	0.00%	$22.17	-	-	-	-	-
D.13.10	Monitor LCD - 20 inch	Per Monitor / Month	0.00%	$24.38	-	-	-	-	-
D.13.10	Monitor LCD – 24 inch	Per Monitor / Month	0.00%	$28.15	-	-	-	-	-
D.13.10	Monitor LCD – 27 inch	Per Monitor / Month	0.00%	$32.48	-	-	-	-	-
D.13.10	Monitor LCD – 30 inch	Per Monitor / Month	0.00%	$34.41	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.13.11	Monitor CRT - 17 inch (EOL)	Per Monitor / Month	0.00%	$7.77	-	-	-	-	-
D.13.11	Monitor CRT - 21 inch (EOL)	Per Monitor / Month	0.00%	$12.36	-	-	-	-	-
D.13.12	Software Integration /Pkging Labour	Per Hour	100.00%	$114.64	-	-	-	-	-
D.13.13	Software Distribution Fee	Per Distribution	100.00%	$171.91	-	-	-	-	-
D.13.14	B & W Printer Low Volume	Per Printer / Month	0.00%	$30.72	-	-	-	-	-
D.13.14	B & W Printer Medium Volume	Per Printer / Month	0.00%	$40.32	-	-	-	-	-
D.13.14	B & W Printer High Volume	Per Printer / Month	0.00%	$116.93	-	-	-	-	-
D.13.14	Colour Printer Low Volume	Per Printer / Month	0.00%	$35.23	-	-	-	-	-
D.13.14	Colour Printer Medium Volume	Per Printer / Month	0.00%	$44.45	-	-	-	-	-
D.13.14	Colour Printer High Volume	Per Printer / Month	0.00%	$64.13	-	-	-	-	-
D.13.14	Colour Printer Maximum Volume	Per Printer / Month	0.00%	$106.94	-	-	-	-	-
D.13.15	Printer Support Low Volume	Per Printer / Month	100.00%	$35.23	-	-	-	-	-
D.13.15	Printer Support Medium Volume	Per Printer / Month	100.00%	$69.53	-	-	-	-	-
D.13.15	Printer Support High Volume	Per Printer / Month	100.00%	$118.86	-	-	-	-	-
D.13.16	Xerox Lease	Per Xerox Device / Month	0.00%	Device Based	-	-	-	-	-

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Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
D.13.17	Xerox service	Per Impression / Month	0.00%	Device Based	-	-	-	-	-
D.13.18	Xerox Printer Support	Per Xerox Device / Month	100.00%	$69.53	-	-	-	-	-
D.13.18	High Volume Xerox Printer Support	Per Xerox Device / Month	100.00%	$118.86	-	-	-	-	-
D.13.19	Xerox Consumables	Per Consumable	0.00%	Usage Based	-	-	-	-	-
D.13.20	Printer Toner / Ink	Per Toner/Ink	0.00%	Usage Based	-	-	-	-	-
D.13.21	Workstation Install/Move/Add/Chg	Per Item / Request	100.00%	$137.30	-	-	-	-	-

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18 BASE VOLUMES

Prices are based on the following volumes. All numbers are monthly base volumes.

Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
4 Application Service Provider Service							
D.4.1.1	Discoverer Maint. on License Purchase	636	636	636	636	636	636
D.4.1.1	Discrete Mfg Read Maint. on Lic. Purcha	46	46	46	46	46	46
D.4.1.1	Discrete Mfg Update Maint. on Lic Purch	83	83	83	83	83	83
D.4.1.1	Financials Read Maint. on License Purch	22	22	22	22	22	22
D.4.1.1	Financials Update Maint. on Lic Purchase	274	274	274	274	274	274
D.4.1.1	iExpense Maintenance on License Purchase	1,852	1,852	1,852	1,852	1,852	1,852
D.4.1.1	iProcurement Maintenance on Lic Purchase	2,565	2,565	2,565	2,565	2,565	2,565
D.4.1.1	Mobile Supply Chain Maint on Lic Purchas	47	47	47	47	47	47
D.4.1.1	Order Management Maint on Lic. Purchase	14,447	14,447	14,447	14,447	14,447	14,447
D.4.1.1	Project Acct Read Maint. on Lic Purchase	107	107	107	107	107	107
D.4.1.1	Project Acct Update Maint. on Lic Purchase	286	286	286	286	286	286
D.4.1.1	Project Management Maint on Lic Purchase	97	97	97	97	97	97
D.4.1.1	Purchasing Read Maint. on Lic Purchase	4	4	4	4	4	4
D.4.1.1	Purchasing Update Maint. on Lic Purchase	353	353	353	353	353	353
5 Distributed Server and Managed Service							
D.5.1	Distributed Server Hosting - Windows Tier 1	24	24	24	24	24	24
D.5.1	Distributed Server Hosting - Windows Tier 2	0	0	0	0	0	0
D.5.1	Distributed Server Hosting - Windows Tier 3	26	26	26	26	26	26
D.5.1	Distributed Server Hosting - Windows Tier 4	51	51	51	51	51	51
D.5.1	Distributed Server Hosting - Windows Tier 5	14	14	14	14	14	14
D.5.1	Distributed Server Hosting - Unix Tier 1	26	26	26	26	26	26
D.5.1	Distributed Server Hosting - Unix Tier 2	14	14	14	14	14	14
D.5.1	Distributed Server Hosting - Unix Tier 3	2	2	2	2	2	2

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Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
D.5.1	Distributed Server Hosting - Unix Tier 4	16	16	16	16	16	16
D.5.1	Distributed Server Hosting - Unix Tier 5	0	0	0	0	0	0
D.5.1	Distributed Server Support - Windows Bronze	5	5	5	5	5	5
D.5.1	Distributed Server Support - Windows Silver	65	65	65	65	65	65
D.5.1	Distributed Server Support - Windows Gold	18	18	18	18	18	18
D.5.1	Distributed Server Support - Windows Platinum	3	3	3	3	3	3
D.5.1	Distributed Server Support - Unix Bronze	40	40	40	40	40	40
D.5.1	Distributed Server Support - Unix Silver	2	2	2	2	2	2
D.5.1	Distributed Server Support - Unix Gold	16	16	16	16	16	16
D.5.1	Distributed Server Support - Unix Platinum	0	0	0	0	0	0
D.5.1	Shared Database Licensing - Oracle Standard Tier 1	6	6	6	6	6	6
D.5.1	Shared Database Licensing - Oracle Standard Tier 2	4	4	4	4	4	4
D.5.1	Shared Database Licensing - Oracle Standard Tier 3	2	2	2	2	2	2
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 1	20	20	20	20	20	20
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 2	10	10	10	10	10	10
D.5.1	Shared Database Licensing - Oracle Enterprise Tier 3	0	0	0	0	0	0
D.5.1	Shared Database Licensing - Microsoft SQL Tier 2	0	0	0	0	0	0
D.5.1	Shared Database Licensing - Microsoft SQL Tier 3	0	0	0	0	0	0
D.5.1	Dedicated Oracle Standard Database Licensing - Named User	10	10	10	10	10	10
D.5.1	Dedicated Oracle Standard Database Licensing - CPU	8	8	8	8	8	8
D.5.1	Dedicated Oracle Enterprise Database Licensing - Named User	325	325	325	325	325	325
D.5.1	Dedicated Oracle Enterprise Database Licensing - CPU	12	12	12	12	12	12
D.5.1	Dedicated Microsoft SQL Standard Database Licensing- CPU	5	5	5	5	5	5
D.5.4	Web Hosting	12	12	12	12	12	12
D.5.5	Secure Site WEB Hosting						
D.5.6	File Transfer	6	6	6	6	6	6
D.5.7	Sharepoint Site Setup Fee						
D.5.7	Sharepoint	6	6	6	6	6	6

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Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
6. Mainframe Service							
D.6.2.2	ADABAS CPU Minutes (EOL)	2998	EOL	EOL	EOL	EOL	EOL
D.6.2.3	Non-IMS/ADABAS Batch CPU Minutes	2693	2693	2693	2693	2693	2693
D.6.2.4	IMS/ADABAS Batch CPU Minutes (EOL)	2473	EOL	EOL	EOL	EOL	EOL
D.6.2.5	CICS CPU Minutes	282	282	282	282	282	282
D.6.2.6	DB2 CPU Minutes	19,714	19,714	19,714	19,714	19,714	19,714
D.6.2.7	IMS CPU Minutes (EOL)	2661	EOL	EOL	EOL	EOL	EOL
D.6.2.8	TSO CPU Minutes	172	172	172	172	172	172
D.6.4.3	Print Pages	100	100	100	100	100	100
7 Disaster Recovery Service							
D.7.1	Distributed Infrastructure - DR	3,372	3,372	3,372	3,372	3,372	3,372
8 Project Labour Service							
D.8.1	Administrator	11	11	11	11	11	11
D.8.1	Analyst 1	70	70	70	70	70	70
D.8.1	Analyst 2	295	295	295	295	295	295
D.8.1	Analyst 3	582	582	582	582	582	582
D.8.1	Analyst 4	679	679	679	679	679	679
D.8.1	Consultant	252	252	252	252	252	252
D.8.1	Senior Consultant	0	0	0	0	0	0
D.8.1	Project Manager	127	127	127	127	127	127
D.8.1	Senior Engagement Manager	0	0	0	0	0	0
D 8.2	Hardware Install / Move / Add / Change	38	38	38	38	38	38
D.8.3	Software Support Labour	30	30	30	30	30	30
9 Storage Service							
D.9.1	Long Term Archive - 1st Mth	134	134	134	134	134	134
D.9.2	Long Term Archive	5906	5906	5906	5906	5906	5906
D.9.3	Dist App Storage Local Disk	1551	1551	1551	1551	1551	1551
D.9.4	Dist App Storage Network Attached Disk	5633	5633	5633	5633	5633	5633

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Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
D.9.7	Website Storage Disk	94	94	94	94	94	94
D.9.10.2	Mainframe DASD	133	133	133	133	133	133
D.9.10.3	Mainframe Tape	489	489	489	489	489	489
D.9.10.4	Tape HSM	320	320	320	320	320	320
D.9.11	File Server Storage	9,537	9,537	9,537	9,537	9,537	9,537
D.9.12	Email Storage (50mb blocks)	9,180	9,180	9,180	9,180	9,180	9,180
10 User Connectivity Service							
D.10.1	User ID	3,399	3,399	3,399	3,399	3,399	3,399
D.10.2	User ID w/limited ATCO Domain usage	122	122	122	122	122	122
D.10.4	Internet Access	2,401	2,401	2,401	2,401	2,401	2,401
D.10.5	Instant Messaging	79	79	79	79	79	79
D.10.8	VPN - Remote Client	617	617	617	617	617	617
D.10.9	SSL Secure Remote Access	71	71	71	71	71	71
D.10.10	Citrix Terminal Server	130	130	130	130	130	130
D.10.12	RightFax	50	50	50	50	50	50
11 Network Connectivity Service							
D.11.4	Terminal Server 1 Port	10	10	10	10	10	10
D.11.4	Terminal Server 4 Port	7	7	7	7	7	7
D.11.4	Terminal Server 8 Port	1	1	1	1	1	1
D.11.4	Terminal Server 20 Port	0	0	0	0	0	0
D.11.5	ADSL Light	23	23	23	23	23	23
D.11.6	ADSL Unlimited	3	3	3	3	3	3
D.11.9	Blackberry	261	261	261	261	261	261
D.11.14	Video Conferencing Lease w/ Support	21	21	21	21	21	21
D.11.16	Remote Office WAN Acceleration - Sm Site	9	9	9	9	9	9
D.11.16	Remote Office WAN Acceleration - Lg Site	2	2	2	2	2	2
D.11.17	Ethernet LAN Ext - 100Mb WAN	2	2	2	2	2	2
D.11.17	Ethernet LAN Ext - 10Mb Local 3 Yr	7	7	7	7	7	7

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Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
D.11.17	Ethernet LAN Ext - Remote	12	12	12	12	12	12
D.11.17	Ethernet LAN Ext - Wireless	1	1	1	1	1	1
D.11.18	4 Wire Loop	2	2	2	2	2	2
D.11.18	4 Wire Loop High Speed	1	1	1	1	1	1
D.11.19	Mobility Aircard	532	532	532	532	532	532
D.11.28	Modem Line	297	297	297	297	297	297
12 Voice Service							
D.12.2	Centrex Telephone	59	59	59	59	59	59
D.12.6	Voice Call Centre Set Charges	87	87	87	87	87	87
D.12.13	Recorded Announcement	46	46	46	46	46	46
D.12.14	Recorded Announcement Route	11	11	11	11	11	11
D.12.15	Remote Centre Voice Network Access	22	22	22	22	22	22
D.12.16	Telecom Circuit Fees	197	197	197	197	197	197
D.12.17	Voice Line Charges	3,814	3,814	3,814	3,814	3,814	3,814
D.12.18	Voice AIN Auto Activation Fee	23	23	23	23	23	23
D.12.19	Voice AIN Redirect Line Charge	23	23	23	23	23	23
D.12.20	Voice Feature - Line Appearance	1,825	1,825	1,825	1,825	1,825	1,825
D.12.21	Voice Feature - Voice Mail Basic	839	839	839	839	839	839
D.12.22	Voice Feature - Voice Mail Desktop	19	19	19	19	19	19
D.12.23	Voice Feature - Voice Mail Fax	12	12	12	12	12	12
D.12.24	Voice Feature - Voice Mail Remote Notify	28	28	28	28	28	28
D.12.25	Voice Install, Move, Add, Change	149	149	149	149	149	149
D.12.27	Voice Set Charges	2,782	2,782	2,782	2,782	2,782	2,782
D.12.28	Voice Feature - Call Park	1256	1256	1256	1256	1256	1256
D.12.29	Voice Feature - Call Recording	29	29	29	29	29	29
D.12.31	Voice Set Feature - SC Manager	61	61	61	61	61	61
D.12.32	Voice Set Feature - SC User	164	164	164	164	164	164
D.12.33	Voice Set Feature - Visual Call Waiting	287	287	287	287	287	287

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Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
13 Workstation Service							
D.13.2	PC H/W Operating Lease	1,891	1,891	1,891	1,891	1,891	1,891
D.13.4	PC Support Low	564	564	564	564	564	564
D.13.4	PC Support Medium	663	663	663	663	663	663
D.13.4	PC Support High	663	663	663	663	663	663
D.13.5	Laptop H/W Operating Lease	940	940	940	940	940	940
D.13.8	Laptop Support Low	164	164	164	164	164	164
D.13.8	Laptop Support Medium	302	302	302	302	302	302
D.13.8	Laptop Support High	471	471	471	471	471	471
D.13.10	Monitor LCD - 19 inch	2,756	2,756	2,756	2,756	2,756	2,756
D.13.10	Monitor LCD - 20 inch	111	111	111	111	111	111
D.13.14	B & W Printer Medium Volume	180	180	180	180	180	180
D.13.14	B & W Printer High Volume	32	32	32	32	32	32
D.13.14	Colour Printer Low Volume	0	0	0	0	0	0
D.13.14	Colour Printer Medium Volume	4	4	4	4	4	4
D.13.14	Colour Printer High Volume	19	19	19	19	19	19
D.13.14	Colour Printer Maximum Volume	16	16	16	16	16	16
D.13.15	Printer Support Low Volume	39	39	39	39	39	39
D.13.15	Printer Support Medium Volume	195	195	195	195	195	195
D.13.15	Printer Support High Volume	67	67	67	67	67	67
D.13.16	Xerox Lease	3,375	3,375	3,375	3,375	3,375	3,375
D.13.17	Xerox Service	4,285	4,285	4,285	4,285	4,285	4,285
D.13.18	Xerox Printer Support	200	200	200	200	200	200
	Software Provisioning (Applications Above Core)	425	425	425	425	425	425

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INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule E
Special Terms

ATCO Electric

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SCHEDULE E – SPECIAL TERMS

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1 INTRODUCTION

This is Schedule E to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1 Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"COLA" has the meaning described in Schedule D (Price Schedule).

2 SPECIAL TERMS

ATCO I-Tek will provide the following under these special terms:

2.1 Tablet PC Hardware Operating Lease

The Tablet PC Hardware Operating Lease provides the Client with a tablet PC lease for the Client to conduct business. Tablet specifications are subject to change without notice as technology changes.

2.1.1 Products or Services Provided within the Fee

The following are included in the price:

- Operational lease of tablet hardware with 4 year refresh
- Hardware standard review, selection and configuration
- Hardware vendor management including procurement
- Hardware asset management
- Hardware installation
- Testing and integration
- Infrastructure management
- Workstation management
- 24x7x365 Level 1 Help Desk Support
- Level 2 Break/Fix support (during Business Hours)
- Lever 3 Break/Fix support (during Business Hours)
- Technology roadmap and recommendations
- Wiping hard drives at time of disposal

- Removal and disposal of retired hardware

2.1.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- All support related items other than hardware
- Special hardware requested by the Client
- Wiring for new locations

2.2 Tablet PC Support

The Tablet PC Support provides all services relating to the support of the leased tablet PC. There are three levels of tablet support: low, medium, and high. The level of support needed is determined by the business needs of the Client. For all three levels, the Core software applications are supported. A list of Core software applications included in the Tablet PC Support rate is maintained and updated by ATCO I-Tek on a regular basis and is published on the Client intranet website. Any software applications required in addition to the Core group is considered "above Core".

The Level of support is determined as follows:

- 0-4 software applications: Tablet PC Support Low
- 5-8 software applications: Tablet PC Support Medium
- 9+ software applications: Tablet PC Support High

Exceptions:

- Clients with tablets that are not connected to the ATCO I-Tek network will be billed for Tablet PC Support at the MEDIUM level.

2.2.1 Products or Services Provided within the Fee

The following are included in the price:

- Standard Tablet PC build
- Core software installation and support
- 24x7x365 Level 1 Help Desk Support
- Core software asset management
- Core software standards review, selection and configuration
- Core software testing, integration, installation and maintenance
- Core software licensing
- Core software suite and Windows software updates/patches for functional and/or security purposes

- Technology roadmap and recommendations
- Anti-Virus software updates
- Locked down configuration
- Level 2 Break/Fix support (during Business Hours)
- Level 3 Break/Fix support (during Business Hours)
- LAN/WAN environment access

2.2.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Hardware fees
- Wiring for new locations
- Any major upgrade in Core software that would result in rework of current standard workstation build
- Any support efforts when related to Clients with administrative access or multi-platform configurations
- Any non-standard operating system builds
- Support for above Core software applications will be billable at the Time and Materials Rate.

2.3 Rugged Hardware Basic Support

The Rugged Hardware Basic Support provides connectivity and support for ATCO Electric purchased laptops that are only used to connect to ATCO Electric Work Force Management System (WFMS).

All hardware and software support for the WFMS rugged laptops will be completed by ATCO I-Tek.

2.3.1 Products or Services Provided within the Fee

The following are included in the price:

- Standard rugged laptop WFMS build with the following software installed:
    - Windows XP (OEM included with laptop)
    - Windows XP Updates
    - Adobe Acrobat Reader
    - Winzip
    - Antivirus endpoint protection

  - Nortel VPN Client
  - Tivoli Mobile Console
  - Java Runtime Environment
  - .Net Framework
  - MS Bluetooth Disabler
  - G/Technology MobileViewer
  - Redline Data Copy Tool
  - LockOut Pro
  - One Mobile
  - Inservice Mobile
- 24x7x365 Level 1 Help Desk Support
- Software asset management. for applications provided by ATCO I-Tek
- Software testing, integration, installation and maintenance for installed applications
- Software licensing for the following applications:
  - Adobe Acrobat Reader
  - Winzip
  - Antivirus endpoint protection
  - Nortel VPN Client
  - Tivoli Mobile Console
- Windows software updates/patches for functional and/or security purposes
- Anti-Virus software updates
- Locked down configuration
- Level 2/3 software Break/Fix support (during Business Hours)
- Limited LAN/WAN environment access
- Limited Infrastructure environment access

2.3.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Rugged Laptop Hardware review, selection, procurement and configuration
- Hardware vendor management

- Hardware product sparing
- Hardware asset management
- Wiring for new locations
- Any major upgrade in Base software that would result in rework of current standard workstation build
- Any support efforts when related to Clients with administrative access or multi-platform configurations
- Support for WFMS specific software may be billable.
- Hardware installation
- Level 2/3 hardware break/fix support (during Business Hours)
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

2.4 Rugged Hardware Above Core Support

The Rugged Hardware Above Core Support provides connectivity and support for ATCO Electric purchased laptops that are only used to connect to that ATCO Electric Work Force Management System (WFMS) and which require the Core suite of software.

All hardware and software support for the WFMS rugged laptops will be completed by ATCO I-Tek.

2.4.1 Products or Services Provided within the Fee

The following are included in the price:

- Standard rugged laptop WFMS build with the following software installed:
    - ATCO standard Core suite of Software
    - G/Technology MobileViewer
    - Redline Data Copy Tool
    - LockOut Pro
    - One Mobile
    - Inservice Mobile
- Core software installation and support
- Core software asset management
- Core software standards review, selection and configuration
- Core software testing, integration, installation and maintenance
- Core software licensing

- Core software suite and Windows software updates/patches for functional and/or security purposes
- 24x7x365 Level 1 Help Desk Support
- Software asset management for applications provided by ATCO I-Tek
- Software testing, integration, installation and maintenance for installed applications
- Windows software updates/patches for functional and/or security purposes
- Anti-Virus software updates
- Locked down configuration
- Level 2/3 software Break/Fix support (during Business Hours)
- LAN/WAN environment access
- Infrastructure environment access

2.4.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Moves/adds/changes
- Rugged Laptop Hardware review, selection, procurement and configuration
- Hardware vendor management
- Hardware product sparing
- Hardware asset management
- Wiring for new locations
- Any major upgrade in Base software that would result in rework of current standard workstation build
- Any support efforts when related to Clients with administrative access or multi-platform configurations
- Support for WFMS specific software may be billable.
- Hardware installation
- Level 2/3 hardware break/fix support (during Business Hours)
- Wiping hard drives at time of disposal
- Removal and disposal of retired hardware

2.5 Message Broker Middleware Hosting

The Message Broker Middleware Hosting is an advanced enterprise service bus that provides connectivity and universal data transformation. This service facilitates the delivery of information across and between multiple diverse systems and applications.

2.5.1 Products or Services Provided within the Fee

The following are included in the price:

- Message Broker integration tools
- Message Broker integration infrastructure
- Maintenance of the base system and environments

2.5.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Installation, development, and customization of application specific Message Broker connectivity
- Maintenance and operation of the Message Broker application specific interfaces

2.6 Education Access Portal – ATCO Electric

The Education Access Portal provides all ATCO Electric Clients with access to an external training website without the requirement of Internet access.

2.6.1 Products or Services Provided within the Fee

- Access to an external training website

2.6.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- Maintenance and support of ATCO Electric specified training sites
- Adding additional external websites to this service
- Internet access

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2.7 Uninterrupted Power Supply 4 Hour

The Uninterrupted Power Supply (UPS) 4 Hour service provides network devices with protection from unscheduled power outages. This service will provide up to four hours of battery power to the connected devices.

2.7.1 Products or Services Provided within the Fee

The following are included in the price:

- Operation and maintenance of the UPS hardware
- Initial purchase of batteries

2.7.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the UPS
- Purchase of replacement batteries, including shipping and handling
- Recycling of old batteries

2.8 T1 Network

The T1 Network option provides a private, dedicated and secure connection from the corporate network to the client location. This option is only available at locations in Alberta where the T1 service is offered by a telecommunication service provider.

Each T1 Network service will be custom price based upon the specific client location.

2.8.1 Products or Services Provided within the Fee

The following are included in the price:

- T1 Connection from the corporate network to the client location.
- Operation and maintenance of the networking hardware.
- Capacity planning and design, refresh, vendor management, monitoring, and support for included service components.
- Core network components including routers, switches, and telecommunication circuits. Data Centre facilities for the core network components.

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2.8.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs of the T1 Service
- Moves and changes

2.9 Intrusion Detection A201 w/1 Port

The Intrusion Detection (IDS) A201 w/1 Port service provides for the detection of malicious network activities such as denial-of-service attacks, port scans, and attacks against services and/or applications that have known vulnerabilities. The IDS A201 w/Port service compliments a firewall to provide a complete security solution. This service provides one network port to monitor one physical network segment, and is available to remote sites requiring additional network security monitoring.

2.9.1 Products or Services Provided within the Fee

The following are included in the price:

- Operation and maintenance of the IDS hardware and software
- Real-time notification of alerts when network attacks are detected
- Logging and monitoring of security events
- Daily archival of event logs (up to 180 days)

2.9.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- One time installation of the IDS system
- Support of Client-owned networks behind the firewall (outside of the ATCO Corporate network)
- Any additional network equipment required to connect the sensors to the network

2.10 Wireless Meter Reading on 1X

The Wireless Meter Reading on 1X is a Wide Area Network (WAN) service that provides a private, dedicated, and high-speed connection between ATCO Electric Meter devices and the ATCO Corporate network. Speeds vary from 1.536 Mbps to 10 Mbps and are dependent upon the Mobile Carrier service.

2.10.1 Products or Services Provided within the Fee

The following are included in the price:

- Management and setup of the service
- Management of the service provider contracts
- Invoice administration
- Secure network connection
- Operation and maintenance of the firewall

2.10.2 Products or Services not Provided within the Fee (Additional charges will apply)

The following are excluded from the price:

- One time installation costs
- Moves and changes
- Meter certification
- Meter device costs, including Mobility Carrier rate plan (responsibility of the Client)
- Any investigation into charges
- Bandwidth capacity upgrades

2.11 ASP Service – ATCO Enterprise Applications

2.11.1 Application Hosting, Support and Disaster Recovery Services

Scope of services and associated fees are dependant on the number of modules in use, number of named users and configuration of the system including interfaces and extensions. Scope of services and associated fees will be handled through the Statement of Work process. Disaster Recovery is specific to each application as defined and authorized by the Client.

3 PRICING

The following table is to demonstrate base pricing during the Term (in 2009 Canadian dollars).

Schedule Reference	Service Description	2010 – 2015 Pricing (excludes COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
E.2.1	Tablet PC H/W Operating Lease	Per Tablet / Month	$170.60	$167.19	$163.84	$160.57	$157.36	$154.21
E.2.2	Tablet PC Support Low	Per Tablet / Month	$127.70	$126.17	$124.65	$123.16	$121.68	$120.22
E.2.2	Tablet PC Support Medium	Per Tablet / Month	$131.80	$130.22	$128.66	$127.11	$125.59	$124.08
E.2.2	Tablet PC Support High	Per Tablet / Month	$164.50	$162.53	$160.58	$158.65	$156.74	$154.86
E.2.3	Rugged HW Basic Support	Per Rugged Laptop / Month	$105.50	$104.23	$102.98	$101.75	$100.53	$99.32
E.2.4	Rugged HW Above Core Support	Per Rugged Laptop / Month	$237.30	$234.45	$231.64	$228.86	$226.11	$223.40
E.2.5	Message Broker Middleware Hosting	Per Month	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based	Usage Based
E.2.6	Education Access Portal - ATCO Electric	Per Month	$591.00	$582.14	$573.41	$564.81	$556.34	$547.99
E.2.7	UPS - 4 Hour	Per UPS Device / Month	$147.80	$145.58	$143.40	$141.25	$139.13	$137.04
E.2.8	T1 in Drumheller	Per Site / Month	$1,985.17	$1,955.41	$1,926.09	$1,897.20	$1,868.75	$1,840.70
E.2.8	T1 in Grande Prairie	Per Site / Month	$2,306.38	$2,271.80	$2,237.73	$2,204.17	$2,171.12	$2,138.53
E.2.8	T1 in Jasper	Per Site / Month	$2,306.38	$2,271.80	$2,237.73	$2,204.17	$2,171.12	$2,138.53
E.2.9	Intrusion Detection A201 w/1 Port	Per IDS Device / Month	$1,645.84	$1,621.17	$1,596.85	$1,572.91	$1,549.32	$1,526.06
E.2.10	Wireless Meter Reading	Per Meter Device / Month	$3,688.83	$3,633.53	$3,579.04	$3,525.36	$3,472.49	$3,420.38
E 2.11.1	Financial System Hosting & Support	Per Month	$80,600.00	$79,632.80	$78,677.21	$77,733.08	$76,800.28	$75,878.68

Schedule Reference	Service Description	2010 – 2015 Pricing (excludes COLA)						
		Billing Metric	2010	2011	2012	2013	2014	2015
E2.11.1	Financial System Disaster Recovery	Per Month	$4,381.00	$4,328.43	$4,276.49	$4,225.17	$4,174.47	$4,124.37

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4 PRICE SCHEDULE

The following table is based upon an estimated COLA of 3%, of which is applied to the labour component percentage (in Canadian dollars).

Schedule Reference	Service Description	Billing Metric	Lab. Comp. %	2010 – 2015 Price Schedule					
				2010	2011	2012	2013	2014	2015
E.2.1	Tablet PC H/W Operating Lease	Per Tablet / Month	0%	$170.60	-	-	-	-	-
E.2.2	Tablet PC Support Low	Per Tablet / Month	100.00%	$131.53	-	-	-	-	-
E.2.2	Tablet PC Support Medium	Per Tablet / Month	100.00%	$135.75	-	-	-	-	-
E.2.2	Tablet PC Support High	Per Tablet / Month	100.00%	$169.44	-	-	-	-	-
E.2.3	Rugged HW Basic Support	Per Rugged Laptop / Month	100.00%	$108.67	-	-	-	-	-
E.2.4	Rugged HW Above Core Support	Per Rugged Laptop / Month	100.00%	$244.42	-	-	-	-	-
E.2.5	Message Broker Middleware Hosting	Per Month	40.00%	Usage Based	-	-	-	-	-
E.2.6	Education Access Portal - ATCO Electric	Per Month	35.00%	$597.21	-	-	-	-	-
E.2.7	UPS - 4 Hour	Per UPS Device / Month	35.00%	$149.35	-	-	-	-	-
E.2.8	T1 in Drumheller	Per Site / Month	35.00%	$2,006.01	-	-	-	-	-
E.2.8	T1 in Grande Prairie	Per Site / Month	35.00%	$2,330.60	-	-	-	-	-
E.2.8	T1 in Jasper	Per Site / Month	35.00%	$2,330.60	-	-	-	-	-
E.2.9	Intrusion Detection A201 w/1 Port	Per IDS Device / Month	35.00%	$1,663.12	-	-	-	-	-

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E.2.10	Wireless Meter Reading	Per Meter Device / Month	35.00%	$3,727.56	-	-	-	-	-
E 2.11.1	Financial System Hosting & Support	Per Month	60.00%	$82,050.80	-	-	-	-	-
E 2.11.1	Financial System Disaster Recovery	Per Month	60.00%	$4,459.86	-	-	-	-	-

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5 BASE VOLUMES

Prices are based on the following volumes. All numbers are monthly base volumes.

Schedule Reference	Service Description	2010 – 2015 Base Volumes					
		2010	2011	2012	2013	2014	2015
E.2.1	Tablet PC H/W Operating Lease	17	17	17	17	17	17
E.2.2	Tablet PC Support Low	11	11	11	11	11	11
E.2.2	Tablet PC Support Medium	5	5	5	5	5	5
E.2.2	Tablet PC Support High	1	1	1	1	1	1
E.2.3	Rugged HW Basic Support	208	208	208	208	208	208
E.2.4	Rugged HW Above Core Support	31	31	31	31	31	31
E.2.5	Message Broker Middleware Hosting	2	2	2	2	2	2
E.2.6	Education Access Portal - ATCO Electric	1	1	1	1	1	1
E.2.7	UPS - 4 Hour	2	2	2	2	2	2
E.2.8	T1 in Drumheller	1	1	1	1	1	1
E.2.8	T1 in Grande Prairie	1	1	1	1	1	1
E.2.8	T1 in Jasper	1	1	1	1	1	1
E.2.9	Intrusion Detection A201 w/1 Port	2	2	2	2	2	2
E.2.10	Wireless Meter Reading	1	1	1	1	1	1
E 2.11.1	Financial System Hosting & Support	1	1	1	1	1	1
E 2.11.1	Financial System Disaster Recovery	1	1	1	1	1	1

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INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule F
Termination Transition Plan

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A. Introduction

This is Schedule F to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek Inc. ("**ATCO I-Tek**") and Client.

B. Termination Transition Plan

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

1. Detailed Termination Transition Plan

Upon a notice of termination being given under this Agreement, a detailed Termination Transition Plan shall be prepared at the Client's sole cost and expense pursuant to a Statement of Work, and shall include each of the following items:

(a) Name of Party to whom the Services shall be transitioned

(b) Scope Statement

(c) Format and Form of Deliverables

(d) Transition Team Members including steering committee

(e) Client prepared list of Employees requested to transition (to be negotiated with Supplier)

(f) List of Software used by Client at the date of termination

(g) List of Hardware used by Client at the date of termination

(h) List of 3rd party contracts used by Client at the date of termination

(i) Review of Statements of Work in effect at the date of termination

(j) Detailed project plan

(k) Detailed Training Requirements

(l) Fees Schedule

(m) Client responsibilities during the Transition Assistance Period

(n) ATCO I-Tek responsibilities during the Transition Assistance Period

(o) Change Implementation

(p) Acceptance Process

(q) Authorization signatures

For illustrative purposes, the following is an example of a logical approach to a Termination Transition plan:

					Year XX												Year YY					
ID	Task Name	Start	Finish	Duration	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
1	Datacenter Commissioning	XX-01-01	XX-06-30	24 Weeks																		
2	Core Data & Voice Network	XX-07-01	XX-08-31	8 Weeks																		
3	Storage Environment (SAN)	XX-09-01	XX-09-30	4 Weeks																		
4	Mainframe & Dist. Server Infrastructure	XX-09-01	XX-10-31	8 Weeks																		
5	WAN, LAN and Voice Campus/Regional	XX-09-01	XX-12-31	16 Weeks																		
6	Distributed Servers - Tools/Applications	XX-11-01	YY-04-30	24 Weeks																		
7	Workstation Tools and Processes	XX-12-01	YY-02-28	12 Weeks																		
8	Workstation Integration & Architecture	YY-01-01	YY-02-28	8 Weeks																		
9	Workstation Migration	YY-02-01	YY-06-30	20 Weeks																		
10	ATCO CIS	YY-02-01	YY-06-30	20 Weeks																		
11	Applications - Other	YY-04-01	YY-06-30	12 Weeks																		
12	Oracle E-Business	YY-02-01	YY-06-30	20 Weeks																		

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2. Client Data

Upon termination of this Agreement for any reason, ATCO I-Tek shall convert (to industry standard file formats) and make available to Client, or as Client directs, all Client Data in the possession, custody or control of ATCO I-Tek, and if no direction is provided by Client to ATCO I-Tek, the same shall be delivered up to Client within one hundred eighty (180) days following termination of this Agreement. Client shall pay for any required conversion services (in the event Client Data is stored in a proprietary or confidential file format) at the Time and Materials Rate.

3. Return of Client Property

At the end of the Transition Assistance Period, or earlier, where appropriate in the circumstances, ATCO I-Tek shall return to the Client (in the format mutually agreed to in the Termination Transition Plan) all property belonging to Client including without limitation Client Systems, Documentation, Client Data, Client Know-How, IP Rights, IT Assets, and all other property owned by the Client.

4. Return of ATCO I-Tek Property

At the end of the Transition Assistance Period, or earlier, where appropriate in the circumstances, the Client will return to ATCO I-Tek all property belonging to ATCO I-Tek including without limitation ATCO I-Tek Systems, Documentation, ATCO I-Tek Know-How, IP Rights and IT Assets, and all other property owned by ATCO I-Tek.

5. Training

During the Transition Assistance Period, ATCO I-Tek shall provide training related to the Systems and Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work.

6. Third Party Software

During the term of the Agreement, ATCO I-Tek will use commercially reasonable efforts to license third party software in such a way as to enable Client use of these third party licenses, held by ATCO I-Tek and required to run Client Systems, both during the term of the Agreement as well as after termination, pursuant to the terms of the Termination Transition Plan (including pursuant to a sublicense from ATCO I-Tek apart from any other Services).

7. Consulting

During the Transition Assistance Period, where appropriate in the circumstances, ATCO I-Tek shall provide consulting services related to the Systems or Services to be transferred to the Client or its third party service provider as outlined in the Termination Transition Plan or in a Statement of Work.

INFORMATION TECHNOLOGY

MASTER SERVICES AGREEMENT

Schedule G
Benchmarking Terms of Reference

SCHEDULE G - BENCHMARKING TERMS OF REFERENCE

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1. Introduction

This is Schedule G to the Information Technology Master Services Agreement (the "**Agreement**") dated effective January 1, 2010 between ATCO I-Tek and Client.

1.1. Definitions

Whenever used in this Schedule, unless there is something in the subject matter or context inconsistent therewith, capitalized words and terms used herein will have the respective meanings ascribed thereto in the Agreement and the following capitalized terms will have the respective meanings ascribed to them as follows:

"**Benchmarker**"	means the organization or individual contracted pursuant to the Agreement to prepare the benchmarking study as described in greater detail below.
"**Fair Market Value**"	means the average of the prices charged by other well-managed service providers for work of a similar nature, type and volume.
"**Peer Organizations**"	means the organizations or entities selected by the Benchmarker to be used for Benchmarking.

1.2. Purpose of This Schedule

This Schedule specifies the qualifications of, and process used to select, the Benchmarker and Peer Organizations, and describes the Benchmarking scope, including the Benchmarking content and approach for evaluating the results of the Benchmarking.

2. Benchmark Scope

2.1. Benchmarking Content

The following subject matter will be benchmarked:

- The Services performed;
- The Service Levels achieved for the Services;
- Geographical service locations of the Client;
- The combined billing unit volumes of ATCO Gas, ATCO Electric and ATCO Pipelines and any other applicable utility volumes;
- The overall terms and conditions of the Agreement; and
- The fees, considered as a whole, with consideration to the foregoing factors.

The Benchmarker will also consider:

- The Services performed giving recognition to the fact that Tier 2 Services and Tier 3 Services as outlined in the Agreement can be provided by an alternate service provider;
- Age of technologies used;
- Nature and complexity of technologies utilized;

- Number of applications used;
- Client Industry deregulation;
- ATCO I-Tek pays Third Party fees on behalf of the Client;

The Benchmarker will use its Benchmarking methodology to evaluate the overall competitiveness of the fees for the Services performed in aggregate and the Service Levels achieved, when compared to Peer Organizations providing equivalent services and service levels with similar complexity, risk and volumes as the Services and Service Levels hereunder, including to establish whether the fees are at Fair Market Value.

ATCO I-Tek and the Client acknowledge and agree that the Benchmarker shall make appropriate adjustments to the information and data obtained in respect of Peer Organizations ("**Adjustments**") in order to provide assurance that such information and data can be properly, fairly and equitably compared to the Services, the Service Levels and the fees.

The Benchmarking analysis will not include any review of the ATCO I-Tek's costs for products and services, internal business processes, organization structure, management practices and/or human resource practices.

2.2. Methodology for Benchmarking

ATCO I-Tek hereby consents to Client's use of any Benchmarker listed in Appendix 1 (Approved List of Benchmarkers) for the purposes of the defined Benchmark. Such Benchmarker list meets the qualifications and criteria for selection. The Benchmarker shall be engaged on terms consistent with Article 7 (Reviews) of the Agreement and this Section and otherwise acceptable to Client.

The timing of the Benchmarking shall be consistent with the terms of Article 7.3 (Price Reviews) of the Agreement.

3. The Benchmarker

3.1. Qualifications

The Benchmarker must:

- Be an independent Benchmarker from a North American recognized, reputable firm, acceptable to both Parties;
- Must not be a provider of the Services, direct Client competitor, or a direct Supplier competitor, or affiliated or associated with either Party in such a manner that an objective person would regard the Benchmarker as likely to have a material conflict of interest, and therefore be unable to conduct the benchmark study objectively and independently.
- Have a database with a sufficient number of organizations to make reliable comparisons;
- Have experience benchmarking service providers in the Information Technology industry, those who provide services equivalent to the Services; and
- Have demonstrated experience benchmarking all the subject matter to be benchmarked.

3.2. Selection Process

The process used to amend Appendix 1 (Approved List of Benchmarkers) shall be agreed upon by ATCO I-Tek and the Client within a reasonable time. If the Parties cannot agree on such amendment process, either Party may refer the matter to the dispute resolution process set forth in Article 16 (Dispute Resolution) of the Agreement.

3.3. Confidentiality

The Benchmarker shall be required to execute a Non-Disclosure Agreement in a form acceptable to ATCO I-Tek and the Client, acting reasonably.

4. Peer Organizations

4.1. Selection

In determining who the Peer Organizations to ATCO I-Tek are, the Benchmarker shall follow these principles:

- The type of services being provided by the Peer Organization should be substantially equivalent to those provided by ATCO I-Tek;
- The risk and liability being assumed by the Peer Organization should be substantially similar to that assumed by ATCO I-Tek; and
- A Peer Organization cannot be a division or affiliate of an integrated utility company.

4.2. Number of Peer Organizations

The Benchmarker shall review a commercially reasonable and appropriate number of Peer Organizations in North America.

4.3. Additional Sources of Information

The Parties acknowledge that the Benchmarker will determine commercially reasonably appropriate sources of additional information to complete the Benchmarking study.

5. Evaluating Results

The Benchmarker will report on the fees set forth in the then current Schedule D (Pricing) based on a Benchmarking review undertaken in accordance with this Schedule, including Sections 2 (Benchmark Scope), 3 (The Benchmarker) and 4 (Peer Organizations):

The Benchmarker will provide ATCO I-Tek and the Client with a Benchmarking report setting forth the results of the benchmarking process.

Appendix 1 – Approved List of Benchmarkers

The criteria for an approved Benchmarker are outlined in Section 3.1 (Qualifications) of this Schedule. This list shall be reviewed by ATCO I-Tek and Client as part of the annual Service Review. Any additions or deletions to this list must be mutually agreed to and is also subject to approval of the Alberta Utilities Commission (AUC).

The list of Approved Benchmarkers is:

- Booz Allen Hamilton Inc.
- Compass Management Consulting Limited/Utilipoint International Inc.
- Energy Insights Inc, an IDC Company/Pacific Economics Group
- Gartner, Inc.

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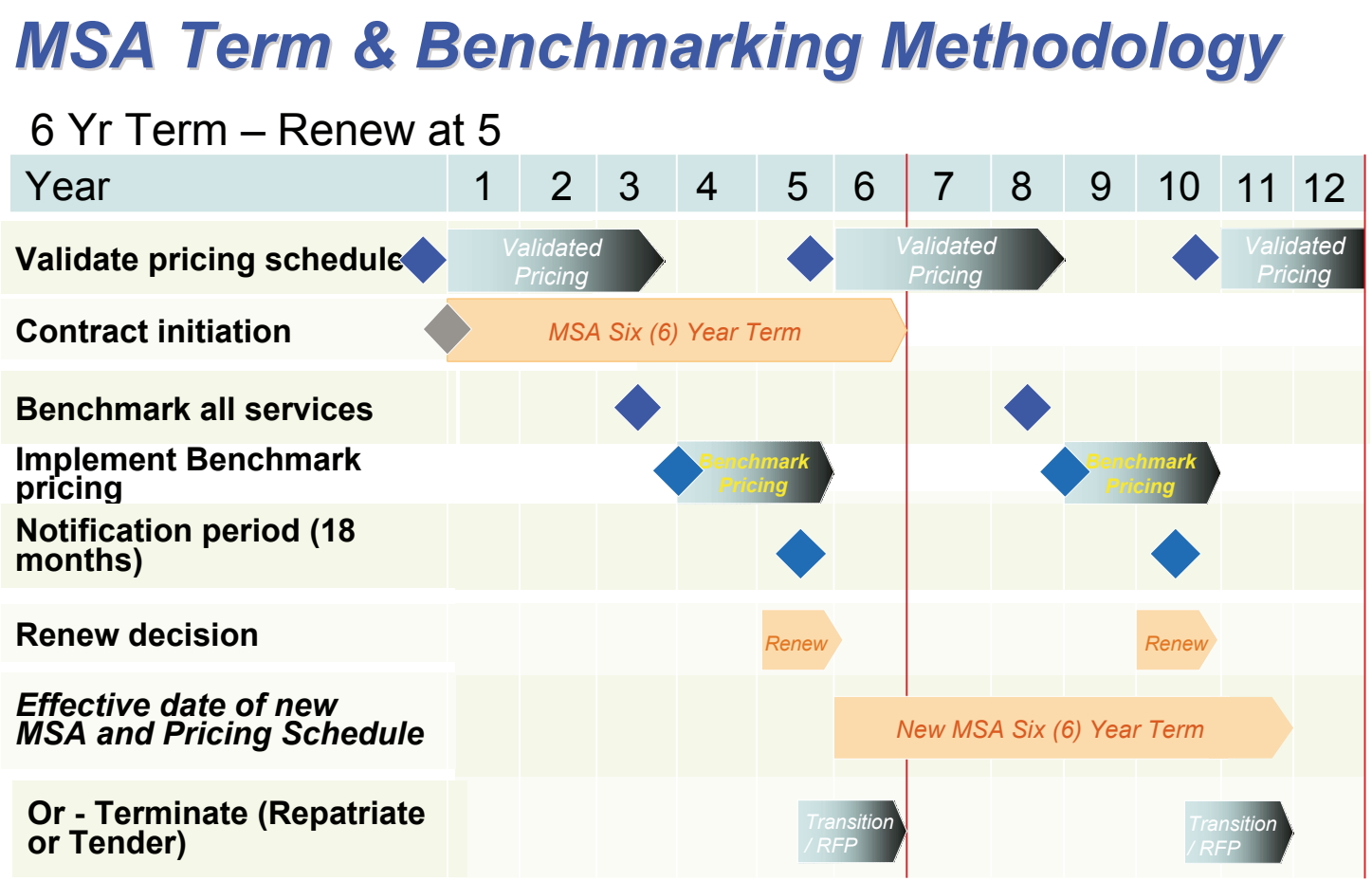
Appendix 2 - MSA Term and Benchmarking Methodology



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NORTH OF 60 COMPANIES
AND
ATCO GAS

ENERGY STUDIES

Services Agreement #23

September 1, 2013

Schedule "A" to the Master Services Contract

ENERGY STUDIES

dated September 1, 2013 between

North of 60 Companies and ATCO Gas

SCOPE OF SERVICES

ATCO Gas will provide comprehensive study services for energy solutions for the North of 60 Companies, as requested.

Schedule "B" to the Master Services Contract

ENERGY STUDIES

dated September 1, 2013 between

North of 60 Companies and ATCO Gas

TERMS AND CONDITIONS

1. Term of Agreement

This agreement will commence September 1, 2013 and will remain in effect at perpetuity, with annual review and renewal.

2. Cost of Service Provided

All services provided by ATCO Gas are on a Direct Cost Basis, consistent with ATCO Gas policy 80.05, Accounting for Non-Utility Services.

3. Billing

The Financial Services department of ATCO Gas will be responsible for the charging of costs associated with this agreement through the inter-company debit note process, and the provision of details supporting the charges. Settlement of these charges will be consistent with the normal settlement date for inter-company transactions.

Schedule "C" to the Master Services Contract

ENERGY STUDIES

dated September 1, 2013 between

North of 60 Companies and ATCO Gas

NORTH OF 60 COMPANIES' REPRESENTATIVES

Bobbi Lambright
President, Distribution
A Division of ATCO Electric Ltd.
10035 - 105 Street
Edmonton, AB T5J 2V6
Phone: (780) 420-7765
E-mail: bobbi.lambright@atcoelectric.com

Signature

August 27, 2013
Date

Dwight Redden
General Manager, North of 60 Companies
100-1100 1st Avenue
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Email: dwight.redden@atco.com

Signature

AUGUST 27, 2013
Date*

Schedule "D" to the Master Services Contract

ENERGY STUDIES

dated September 1, 2013 between

North of 60 Companies and ATCO Gas

ATCO GAS' REPRESENTATIVES

W.C. (Bill) Stephens
President
10035 - 105 Street
Edmonton, AB T5J 2V6
Phone: (780) 420-7223
E-mail: bill.stephens@atcogas.com

Signature

20130821
Date

Wayne Morishita
Director, Marketing & Sales
909 – 11 Avenue S.W.
Calgary, AB T5J 2V6
Telephone: (403) 245-7064
E-mail: wayne.morishita@atcogas.com

Signature

Date

Schedule "D" to the Master Services Contract

ENERGY STUDIES

dated September 1, 2013 between

North of 60 Companies and ATCO Gas

ATCO GAS' REPRESENTATIVES

W.C. (Bill) Stephens
President
10035 - 105 Street
Edmonton, AB T5J 2V6
Phone: (780) 420-7223
E-mail: bill.stephens@atcogas.com

_____ _____

Signature Date

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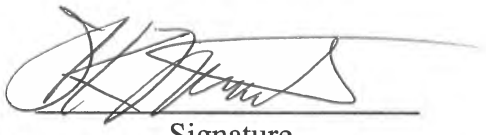
E-mail: wayne.morishita@atcogas.com



Signature

AUG 26/13

Date

NORTH OF 60 COMPANIES
(YUKON ELECTRICAL COMPANY LTD.)
("YUKON ELECTRICAL")
AND
ATCO GAS

LIQUEFIED NATURAL GAS SERVICES ("LNG")

Services Agreement #5

October 1, 2013

Schedule "A" to the Master Services Contract

LIQUEFIED NATURAL GAS SERVICES

dated October 1, 2013 between

Yukon Electrical and ATCO Gas

SCOPE OF SERVICES

ATCO Gas will own or lease, supply, operate and maintain on-site liquefied natural gas (LNG) storage, vaporization equipment, controls, natural gas odorizer, metering and facility safety systems (the "LNG FACILITY") at the following Yukon Electrical location(s):

- Watson Lake Power Generation Plant

Yukon Electrical will own the fuel within the LNG FACILITY.

For each location identified above:

The sizing, specifications and location on-site of the LNG FACILITY will be determined by ATCO Gas based on:

- municipal, territorial and federal safety code requirements
- fuel consumption estimates as given by Yukon Electrical
- fuel logistical delivery estimates as given by Yukon Electrical

ATCO Gas' services to provide natural gas include LNG storage and vaporization services along with expertise related to systems design, purchasing, installation, commissioning, on-going operations support, maintenance, permitting, licensing for the project, Health Safety and Environment policies, procedures and work instructions, regulations and safety.

ATCO Gas will be responsible for installation, including permitting of the LNG FACILITY

ATCO Gas will take all measures to ensure the LNG FACILITY is operable, but does not guarantee uninterruptible service

ATCO Gas will provide specialized training to Yukon Electrical personnel on-site when required to ensure continuity of safe operations

Yukon Electrical will be responsible for installation, including permitting, of appropriate facilities to receive vaporized LNG downstream of the LNG FACILITY outlet flange

Yukon Electrical will supply access to energy (electricity and heat) and telecommunications (phone) on-site required to operate the LNG FACILITY

Yukon Electrical will have on-site personnel integrate equipment monitoring and safety protocols into their normal work routine

Schedule "B" to the Master Services Contract

LIQUEFIED NATURAL GAS SERVICES

dated October 1, 2013 between

Yukon Electrical and ATCO Gas

TERMS AND CONDITIONS

1. Term of Contract

This agreement will commence October 1, 2013 and will remain in effect with annual review and renewal until December 31, 2033.

Either party may terminate this agreement by providing written notice at least 12 months in advance of the termination date. The cost to remove the ATCO Gas owned equipment from the Yukon Electrical site at Watson Lake and restore the site to an unencumbered state will be borne by the terminating party.

2. Cost of Service Provided

All services charged to Yukon Electrical on a For Profit Basis.

ATCO Gas will invoice Yukon Electrical $22,000 per month for service starting October 1, 2013.

ATCO Gas will adjust this amount once per year based on the latest Consumer Price Index (CPI) for Canada, as published by the Bank of Canada.

ATCO Gas agrees not to invoice for this service during months where the LNG FACILITY is not available as required for more than 15 calendar days after notification by Yukon Electrical.

At the request of Yukon Electrical, ATCO Gas will by mutual agreement transfer ownership of all ATCO Gas equipment on-site and terminate the services agreement.

3. Billing

The Financial Services department of ATCO Gas will be responsible for the charging of costs associated with this agreement through the inter-company debit note process, and the provision of details supporting the charges. Settlement of these charges will be consistent with the normal settlement date for inter-company transactions.

Schedule "C" to the Master Services Contract

LIQUEFIED NATURAL GAS SERVICES

dated October 1, 2013 between

Yukon Electrical and ATCO Gas

YUKON ELECTRICAL'S REPRESENTATIVES

Bobbi Lambright
President, Distribution
A Division of ATCO Electric Ltd.
10035 - 105 Street
Edmonton, AB T5J 2V6
Phone: (780) 420-7765
E-mail: bobbi.lambright@atcoelectric.com

Signature _____ Date August 29, 2013

Dwight Redden
General Manager
100-1100 1st Avenue
Whitehorse, Yukon Y1A 3T4
Telephone: (867) 633-7003
Email: dwight.redden@atco.com

Signature _____ Date AUGUST 29, 2013

Schedule "D" to the Master Services Contract

LIQUEFIED NATURAL GAS SERVICES

dated October 1, 2013 between

Yukon Electrical and ATCO Gas

ATCO GAS' REPRESENTATIVES

W.C. (Bill) Stephens
President
10035 - 105 Street
Edmonton, AB T5J 2V6
Phone: (780) 420-7223
E-mail: bill.stephens@atcogas.com

Signature

20130829
Date

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Calgary, AB T5J 2V6
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E-mail: wayne.morishita@atcogas.com

Signature

AUG 28/2013
Date

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

UCG-YECL-22

Reference: May 27, 2013 Application, page 6-1

YECL states "*Property taxes are paid to the communities annually for Yukon Electrical's office building, generation facilities, substation properties and power lines. The increases forecast during the test period are primarily due to planned capital work on the downtown office building in Whitehorse and the Fish Lake Unit #1 building, as well as inflation.*"

Request:

(a) Please explain how often YECL's facilities within municipalities are reassessed such that planned capital work would need to be included so quickly in a property tax budget.

(b) Please explain how property taxes are affected by inflation.

(c) Please provide the actual property taxes paid or expected to be paid in 2013 based on municipal budget deliberations.

Response:

(a) Yukon Electrical's facilities are reassessed annually.

(b) Property taxes increase with inflation. Please refer to WL-YECL-15 Attachment 1 which is the City of Whitehorse 2013-2015 Operating Budget. On pages 26 and 30 of the Attachment, the increase to existing taxes is indicated to be 3.83%.

(c) Actual property taxes paid in 2013 are as per the following table, as compared to Yukon Electrical's forecast of $257,000 for 2013, $265,000 for 2014 and $273,000 for 2015. Based on the latest available information, Yukon Electrical anticipates that it has under forecast Property Tax for the test period.

Property Taxes	**Total**
City of Whitehorse (CoW)	134,588.20
Government of Yukon	51,281.07
Minister of Finance, BC Gov't	6,085.89
Town of Watson Lake	57,240.11
Village of Carmacks	9,113.86
Village of Haines Junction	5,246.80
Village of Teslin	9,698.74
Grand Total	273,254.67

UCG-YECL-23

Reference: May 27, 2013 Application, page 7-1

YECL states "*The impact of the depreciation study is a significant increase in forecast depreciation expense primarily due to the request for reinstatement of a provision for future removal and site restoration in depreciation rates.*"

Request:

(a) Please provide a table that compares YECL's current and proposed depreciation rates with the depreciation rates allowed for Yukon Energy Corporation for similar assets. Include an analysis of the impact that any differences have on the depreciation expense forecast by YECL for the 2013-2015 test period.

(b) Please explain how YECL treated the difference between the depreciation expense allowed to be recovered in rates in 2009 and the depreciation expense identified as incurred in 2010, 2011 and 2012.

(c) Please explain the significant change in amortization of differences between 2009 allowed and the forecast for 2013-2015.

(d) Please provide schedules 7.2, 7.3 and 7.4 showing depreciation expense at existing rates.

(e) Please provide details on the impact of the proposed change in depreciation expense on the overall revenue requirement for 2013, 2014 and 2015 including the change in rate base and return.

Response:

(a) In YEC's 2012-2013 GRA, YEC provided a response to YECL-YEC-1-55(a) Attachment 1, which showed Depreciation Expense and related Rate (%). A large number of accounts had a Note of "n/a" which was stated to reflect asset classes which KPMG reviewed, however a change was deemed unnecessary. In a further information response to YECL-YEC-1-61(d), YEC provided its previous Depreciation Study which was conducted on assets as of December 31, 2003. To the best of Yukon Electrical's knowledge, Table 1 of

YEC's December 31, 2003 Depreciation Study shows the Depreciation Rates that were approved for YEC and, in the vast majority of accounts are still valid for YEC. To the best of Yukon Electrical's knowledge, YEC does not update its depreciation rates to reflect subsequent capital activity of additions and retirements which can have a significant change in the resulting depreciation rates. In Yukon Electrical's opinion, the comparison of depreciation rates from a study that was done based on asset balances as of the end of 2003 (and not updated with subsequent capital activity) to Yukon Electrical's current depreciation study, which developed depreciation parameters as of the end of 2011 and was updated to reflect forecast capital activity, is an inappropriate comparison. Yukon Electrical has nevertheless provided its understanding of YEC's current depreciation rates to Yukon Electrical's proposed depreciation rates in UCG-YECL-23(a) Attachments 1 to 3. The difference in depreciation expense between Yukon Electrical's proposed depreciation rates compared to Yukon Electrical's best understanding of YEC's current depreciations rates is a decrease to Yukon Electrical's forecast depreciation expense of $1.293M, $1.537M, $1.871M for 2013, 2014, and 2015, respectively. The majority of this change is likely due to Yukon Electrical's proposed reinstatement of net salvage in its depreciation rates.

(b) The amount by which actual depreciation expense incurred was higher for each year from 2010-2012 than the depreciation expense allowed to be recovered in rates in 2009 was a reduction to Yukon Electrical's earnings for each of those years.

(c) Please refer to YUB-YECL-83(b). The amortization of differences is developed using the forecast life and net salvage parameters for each fixed asset account. Using the forecast life and net salvage parameters assumes that these parameters have been in existence since day 1 for each fixed asset account and determines a calculated accrued depreciation to the date of the depreciation study. This calculated accrued depreciation is then compared to the actual booked accumulated depreciation. If the booked value is greater than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account, as an annual provision for true-up, resulting in an annual depreciation expense decrease. Similarly, if the booked value is less than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account resulting in an annual depreciation expense increase. Thus, the difference between the previous depreciation study amount

of ($382,000) to the current depreciation study amount of $71,000 reflects depreciation parameter forecast changes.

(d) Please refer to YUB-YECL-83(a) Attachment 1.

(e) Please refer to UCG-YECL-23(e) Attachment 1 for the impact of the change in depreciation parameters as a result of updating the depreciation study, as well as the impact of the reinstatement of a provision for net salvage in depreciation rates, on revenue requirement, rate base and return on rate base. Please note that the requested reinstatement of a provision for net salvage in depreciation rates results in a reduction in rate base and, as a result, a lower return on rate base.

The Yukon Electrical Company Limited
2013 Depreciation Rates
Based on 2013/2015 GTA

Account	Description	Life Parameter	NS Parameter	Composite Rate	2012 Original Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.40%	262,557.87	1.39%		(2,652)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.40%	2,374,620.82	0.97%		(33,957)
42500	Generators	R3-85 / 2052	-10%	2.68%	2,685,841.06	1.18%		(40,288)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.58%	157,864.16		2.22%	(568)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.07%	68,656.70		3.33%	(508)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.50%	177,646.92	1.39%		(3,748)
44401	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.56%	193,505.60		4.00%	851
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.82%	586,223.70	2.50%		(7,738)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	129,917.54		2.22%	(1,000)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.84%	48,460.21		3.33%	237
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.09%	167,738.94	1.39%		(2,852)
44402	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.60%	139,911.46		4.00%	560
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.80%	419,543.17	2.50%		(5,454)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.03%	101,158.38		2.22%	(819)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.93%	10,337.91		3.33%	41
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	3.03%	42,281.93	1.39%		(693)
44403	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2023	-20%	5.30%	185,288.48		4.00%	(2,409)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	7.05%	497,404.95	2.50%		(22,632)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	4.77%	272,311.04		2.22%	(6,944)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	4.82%	24,406.04		3.33%	(364)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.21%	608,472.09	1.39%		(11,074)
44404	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.24%	498,928.74	2.50%		(8,681)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.80%	91,707.86		2.22%	(532)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.63%	5,425.93		3.33%	38
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.79%	218,250.71	1.39%		(3,056)
44405	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.60%	957,181.53		4.00%	3,829
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.22%	663,170.33	2.50%		(11,407)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.79%	119,365.14		2.22%	(680)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.58%	126,010.04		3.33%	945
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.57%	48,891.66	1.39%		(577)
44406	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2033	-20%	3.56%	191,354.03		4.00%	842
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.97%	498,983.00	2.50%		(7,335)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.81%	403,751.15		2.22%	(6,420)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.57%	68,488.84		3.33%	(164)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.25%	264,971.01	1.39%		(4,928)
44407	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.57%	87,965.86		4.00%	378
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.71%	201,226.65	2.50%		(2,435)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	136,596.48		2.22%	(1,079)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.81%	12,646.75		3.33%	66
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.08%	247,965.51	1.39%		(4,191)
44408	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.59%	135,110.10		4.00%	554
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.01%	17,032.82	2.50%		(87)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.87%	43,969.44		2.22%	(286)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.97%	97,465.09		3.33%	351
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.80%	22,503.27	1.39%		(317)
44409	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.53%	149,400.56		4.00%	702
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.47%	244,095.95	2.50%		(4,809)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	58,519.97		2.22%	(462)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.78%	7,891.83		3.33%	43

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2012 Original Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.44%	78,847.51	1.39%		(1,616)
44410	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.63%	112,552.65		4.00%	416
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.94%	790,518.99	2.50%		(11,383)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.14%	119,706.46		2.22%	(1,101)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.86%	75,757.42		3.33%	356
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.66%	359,392.86	1.39%		(4,564)
44411	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2113	-20%	3.60%	805,271.40		4.00%	3,221
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.04%	2,416,037.94	2.50%		(37,207)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.81%	573,096.39		2.22%	(3,381)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.76%	237,902.83		3.33%	1,356
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.52%	1,227.46	1.39%		(26)
44499	Fuel Holders, Producers & Acc. Equipmer	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.23%	430,919.65	2.50%		(7,455)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.13%	26,413.95		2.22%	(240)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.86%	78,852.20		3.33%	371
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.25%	1,384,421.27	1.85%		(5,538)
Distribution								
47100	Land Rigths	R3-75	0%	1.51%	1,330,642.34	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	34,182,587.39		2.86%	(458,047)
47400	Overhead Conductor	R4-45	-80%	4.16%	22,281,820.39		2.50%	(369,878)
47410	Overhead Services	R3-45	-10%	2.57%	2,978,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	22,879,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.87%	3,097,260.23		2.50%	(11,460)
47610	Meters	L0-15	0%	7.65%	1,983,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	7.31%	68,140.35		3.33%	(2,712)
47710	Substation Equipment	R4-40	-10%	2.75%	3,131,073.05	1.82%		(29,119)
47810	Street Lights & Signal Systems	R3-30	-10%	3.77%	9,599,523.57		2.50%	(121,914)
47820	Sentinel Lights	R2-23	0%	2.99%	284,738.28		3.33%	968
47910	Line Transformers	R3-45	-10%	2.66%	28,161,770.91		2.50%	(45,059)
General Plant								
48200	Structures and Improvements	L3-40	0%	2.63%	3,646,079.85	1.82%		(29,533)
48300	Office Furniture and Equipment	SQ-15	0%	5.70%	193,625.00		5.00%	(1,355)
48320	Computer Equipment and Accessories	SQ-5	0%	18.73%	47,030.54		16.29%	(1,148)
48400	Transportation Equipment - Category 1	L0-12	25%	6.44%	2,953,744.17		8.15%	50,656
48500	Tools and Instruments	SQ-15	0%	6.33%	843,412.27		5.00%	(11,217)
48600	Communication Equipment	SQ-15	0%	5.50%	938,160.01		5.00%	(4,691)
48820	Houses	R3-40	-10%	2.93%	474,681.26		2.83%	(475)
					161,520,822.70			(1,292,799)

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2013 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.79%	459,557.87	1.39%		(6,434)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.60%	4,159,620.82	0.97%		(67,802)
42500	Generators	R3-85 / 2052	-10%	2.77%	4,696,841.06	1.18%		(74,680)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.87%	276,864.16		2.22%	(1,800)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.46%	120,656.70		3.33%	(1,363)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.52%	259,646.92	1.39%		(5,530)
44401	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	282,505.60		4.00%	1,158
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.22%	1,186,223.70	2.50%		(20,403)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.10%	189,917.54		2.22%	(1,671)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.92%	70,460.21		3.33%	289
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.06%	167,738.94	1.39%		(2,801)
44402	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	139,911.46		4.00%	574
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.72%	419,543.17	2.50%		(5,118)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.01%	101,158.38		2.22%	(799)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.90%	10,337.91		3.33%	44
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	4.84%	55,281.93	1.39%		(1,907)
44403	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2023	-20%	6.70%	240,288.48		4.00%	(6,488)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	7.03%	497,404.95	2.50%		(22,532)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	5.87%	353,311.04		2.22%	(12,896)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	5.88%	31,406.04		3.33%	(801)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.17%	608,472.09	1.39%		(10,831)
44404	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.17%	498,928.74	2.50%		(8,332)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.77%	91,707.86		2.22%	(504)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.61%	5,425.93		3.33%	39
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.94%	264,250.71	1.39%		(4,096)
44405	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.60%	1,159,181.53		4.00%	4,637
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.17%	663,170.33	2.50%		(11,075)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.87%	144,365.14		2.22%	(938)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.66%	153,010.04		3.33%	1,025
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.54%	48,891.66	1.39%		(562)
44406	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2033	-20%	3.54%	191,354.03		4.00%	880
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.91%	498,983.00	2.50%		(7,036)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.78%	403,751.15		2.22%	(6,299)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.55%	68,488.84		3.33%	(151)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.19%	268,971.01	1.39%		(4,841)
44407	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.56%	88,965.86		4.00%	391
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	204,226.65	2.50%		(2,349)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	138,596.48		2.22%	(1,067)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.80%	12,646.75		3.33%	67
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.07%	252,965.51	1.39%		(4,250)
44408	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.59%	137,110.10		4.00%	562
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	2.95%	17,032.82	2.50%		(77)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.85%	44,969.44		2.22%	(283)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.95%	99,465.09		3.33%	378
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.78%	22,503.27	1.39%		(313)
44409	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.51%	149,400.56		4.00%	732
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.46%	274,095.95	2.50%		(5,372)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	58,519.97		2.22%	(451)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.77%	7,891.83		3.33%	44

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2013 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.36%	78,847.51	1.39%		(1,553)
44410	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2053	-20%	3.62%	112,552.65		4.00%	428
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.86%	790,518.99	2.50%		(10,751)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.11%	119,706.46		2.22%	(1,065)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.85%	75,757.42		3.33%	364
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.79%	433,392.86	1.39%		(6,068)
44411	Fuel Holders, Producers & Acc. Equipme	R4-35 / 2113	-20%	3.61%	972,271.40		4.00%	3,792
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.27%	4,140,037.94	2.50%		(73,279)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.87%	692,096.39		2.22%	(4,499)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.77%	285,902.83		3.33%	1,601
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.40%	1,227.46	1.39%		(25)
44499	Fuel Holders, Producers & Acc. Equipme	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.52%	1,355,919.65	2.50%		(27,390)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.10%	26,413.95		2.22%	(232)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.83%	78,852.20		3.33%	394
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.25%	1,384,421.27	1.85%		(5,538)
Distribution								
47100	Land Rigths	R3-75	0%	1.50%	1,432,642.34	unkown	unkown	
47200	Demand Side Management	SQ-10	0%	10.00%	481,000.00	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	36,821,587.39		2.86%	(493,409)
47400	Overhead Conductor	R4-45	-80%	4.16%	23,984,820.39		2.50%	(398,148)
47410	Overhead Services	R3-45	-10%	2.58%	3,206,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	24,628,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.86%	3,334,260.23		2.50%	(12,003)
47610	Meters	L0-15	0%	8.09%	2,583,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	7.13%	68,140.35		3.33%	(2,589)
47710	Substation Equipment	R4-40	-10%	2.75%	3,370,073.05	1.82%	2.22%	(31,342)
47810	Street Lights & Signal Systems	R3-30	-10%	3.75%	9,995,523.57		2.50%	(124,944)
47820	Sentinel Lights	R2-23	0%	2.93%	284,738.28		3.33%	1,139
47910	Line Transformers	R3-45	-10%	2.65%	30,305,770.91		2.50%	(45,459)
								-
General Plant								-
48200	Structures and Improvements	L3-40	0%	2.67%	4,777,079.85	1.82%		(40,605)
48300	Office Furniture and Equipment	SQ-15	0%	6.67%	199,883.83		5.00%	(3,338)
48320	Computer Equipment and Accessories	SQ-5	0%	20.00%	42,745.55		16.29%	(1,586)
48400	Transportation Equipment - Category 1	L0-12	25%	6.59%	3,512,744.17		8.15%	54,974
48500	Tools and Instruments	SQ-15	0%	6.67%	860,610.61		5.00%	(14,372)
48600	Communication Equipment	SQ-15	0%	6.67%	658,805.95		5.00%	(11,002)
48820	Houses	R3-40	-10%	2.91%	474,681.26		2.83%	(380)
					182,048,640.82			(1,537,231.00)

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Account	Description	Life Parameter	NS Parameter	Composite Rate	2014 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
Production Hydro								
42200	Structures	R2-72 / 2052	-10%	2.91%	626,557.87	1.39%		(9,524)
42300	Reservoirs, Dams & Waterways	R3-103 / 2052	-10%	2.68%	5,666,620.82	0.97%		(96,899)
42500	Generators	R3-85 / 2052	-10%	2.82%	6,394,841.06	1.18%		(104,875)
42600	Accessory Equipment	R3-45 / 2052	-10%	2.97%	376,864.16		2.22%	(2,826)
42700	Misc Plant Equipment	R2-30 / 2052	-10%	4.51%	164,656.70		3.33%	(1,943)
Production Diesel								
	Beaver Creek							
44201	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.43%	259,646.92	1.39%		(5,297)
44401	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.58%	282,505.60		4.00%	1,187
44501	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.33%	1,686,223.70	2.50%		(30,858)
44601	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.07%	189,917.54		2.22%	(1,614)
44701	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.89%	70,460.21		3.33%	310
	Carmacks							
44202	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.03%	167,738.94	1.39%		(2,751)
44402	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.58%	139,911.46		4.00%	588
44502	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	419,543.17	2.50%		(4,825)
44602	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	101,158.38		2.22%	(779)
44702	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.88%	10,337.91		3.33%	47
	Destruction Bay							
44203	Structures and Improvement - Other	R2.5-40 / 2023	-10%	6.94%	79,281.93	1.39%		(4,400)
44403	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2023	-20%	8.52%	346,288.48		4.00%	(15,652)
44503	Generating Equipment & Primer Movers -	S2.5-26 / 2023	-10%	9.53%	1,097,404.95	2.50%		(77,148)
44603	Accessory Electric Equipment - Other	R3-35 / 2023	0%	7.32%	509,311.04		2.22%	(25,975)
44703	Misc Power Plant Equipment - Other	R3-40 / 2023	0%	7.33%	45,406.04		3.33%	(1,816)
	Haines Junction							
44204	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.14%	608,472.09	1.39%		(10,648)
44404	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.62%	180,300.16		4.00%	685
44504	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.11%	498,928.74	2.50%		(8,033)
44604	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.75%	91,707.86		2.22%	(486)
44704	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.59%	5,425.93		3.33%	40
	Old Crow							
44205	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.38%	564,250.71	1.39%		(11,229)
44405	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.65%	2,473,181.53		4.00%	8,656
44505	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.35%	1,163,170.33	2.50%		(21,519)
44605	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.15%	308,365.14		2.22%	(2,868)
44705	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.90%	326,010.04		3.33%	1,402
	Pelly Crossing							
44206	Structures and Improvement - Other	R2.5-40 / 2033	-10%	2.51%	48,891.66	1.39%		(548)
44406	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2033	-20%	3.52%	191,354.03		4.00%	918
44506	Generating Equipment & Primer Movers -	S2.5-26 / 2033	-10%	3.84%	498,983.00	2.50%		(6,686)
44606	Accessory Electric Equipment - Other	R3-35 / 2033	0%	3.76%	403,751.15		2.22%	(6,218)
44706	Misc Power Plant Equipment - Other	R3-40 / 2033	0%	3.53%	68,488.84		3.33%	(137)
	Ross River							
44207	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.19%	285,971.01	1.39%		(5,147)
44407	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.56%	94,965.86		4.00%	418
44507	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.65%	217,226.65	2.50%		(2,498)
44607	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.99%	147,596.48		2.22%	(1,136)
44707	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.81%	13,646.75		3.33%	71
	Stewart Crossing							
44208	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.24%	340,965.51	1.39%		(6,308)
44408	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.61%	185,110.10		4.00%	722
44508	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.36%	23,032.82	2.50%		(198)
44608	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.98%	60,969.44		2.22%	(463)
44708	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.98%	134,465.09		3.33%	471
	Swift River							
44209	Structures and Improvement - Other	R2.5-40 / 2053	-10%	2.76%	22,503.27	1.39%		(308)
44409	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.50%	149,400.56		4.00%	747
44509	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	4.43%	274,095.95	2.50%		(5,290)
44609	Accessory Electric Equipment - Other	R3-35 / 2053	0%	2.96%	58,519.97		2.22%	(433)
44709	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.75%	7,891.83		3.33%	46

The Yukon Electrical Company Limited
2015 Depreciation Rates
Based on 2013/2015 GTA

Account	Description	Life Parameter	NS Parameter	Composite Rate	2014 Forecast Cost	YEC Current Depreciation Rates 2012-2013 GRA Composite Rate	YEC Current Depreciation Rates 2008/09 GRA Composite Rate	Difference
	Teslin							
44210	Structures and Improvement - Other	R2.5-40 / 2053	-10%	3.29%	78,847.51	1.39%		(1,498)
44410	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2053	-20%	3.61%	112,552.65		4.00%	439
44510	Generating Equipment & Primer Movers -	S2.5-26 / 2053	-10%	3.78%	790,518.99	2.50%		(10,119)
44610	Accessory Electric Equipment - Other	R3-35 / 2053	0%	3.08%	119,706.46		2.22%	(1,029)
44710	Misc Power Plant Equipment - Other	R3-40 / 2053	0%	2.83%	75,757.42		3.33%	379
	Watson Lake							
44211	Structures and Improvement - Other	R2.5-40 / 2113	-10%	2.91%	555,392.86	1.39%		(8,442)
44411	Fuel Holders, Producers & Acc. Equipmer	R4-35 / 2113	-20%	3.61%	1,246,271.40		4.00%	4,860
44511	Generating Equipment & Primer Movers -	S2.5-26 / 2113	-10%	4.26%	4,340,037.94	2.50%		(76,385)
44611	Accessory Electric Equipment - Other	R3-35 / 2113	0%	2.95%	887,096.39		2.22%	(6,476)
44711	Misc Power Plant Equipment - Other	R3-40 / 2113	0%	2.78%	364,902.83		3.33%	2,007
	Mobiles							
44299	Structures and Improvement - Other	R2.5-40	-10%	3.32%	1,227.46	1.39%		(24)
44499	Fuel Holders, Producers & Acc. Equipmer	R4-35	-20%	0.00%	-		4.00%	-
44599	Generating Equipment & Primer Movers -	S2.5-26	-10%	4.50%	1,355,919.65	2.50%		(27,118)
44699	Accessory Electric Equipment - Other	R3-35	0%	3.08%	26,413.95		2.22%	(227)
44799	Misc Power Plant Equipment - Other	R3-40	0%	2.81%	78,852.20		3.33%	410
Sub Transmission								
45700	Substation Equipment	R4-50	-10%	2.24%	1,384,421.27	1.85%		(5,399)
Distribution								
47100	Land Rigths	R3-75	0%	1.50%	1,545,642.34	unkown	unkown	
47200	Demand Side Management	SQ-10	0%	10.00%	1,003,000.00	unkown	unkown	
47300	Poles & Fixtures	R3-45	-75%	4.20%	39,744,587.39		2.86%	(532,577)
47400	Overhead Conductor	R4-45	-80%	4.16%	25,874,820.39		2.50%	(429,522)
47410	Overhead Services	R3-45	-10%	2.58%	3,459,753.29	unkown	unkown	
47500	Underground Conduit	R3-45	-50%	3.61%	26,568,822.34	unkown	unkown	
47510	Underground Services	R4-40	-10%	2.86%	3,597,260.23		2.50%	(12,950)
47610	Meters	L0-15	0%	7.40%	2,633,719.10	unkown	unkown	
47630	Automatic Meter Reading	R2.5-15	0%	8.08%	1,327,140.35		3.33%	(63,039)
47710	Substation Equipment	R4-40	-10%	2.75%	3,636,073.05	1.82%	2.22%	(33,815)
47810	Street Lights & Signal Systems	R3-30	-10%	3.76%	10,940,523.57		2.50%	(137,851)
47820	Sentinel Lights	R2-23	0%	2.87%	284,738.28		3.33%	1,310
47910	Line Transformers	R3-45	-10%	2.65%	32,676,770.91		2.50%	(49,015)
								-
General Plant								-
48200	Structures and Improvements	L3-40	0%	2.66%	5,098,079.85	1.82%		(42,824)
48300	Office Furniture and Equipment	SQ-15	0%	6.67%	239,134.61		5.00%	(3,994)
48320	Computer Equipment and Accessories	SQ-5	0%	20.00%	38,278.66		16.29%	(1,420)
48400	Transportation Equipment - Category 1	L0-12	25%	6.98%	4,507,744.17		8.15%	52,965
48500	Tools and Instruments	SQ-15	0%	6.67%	1,021,445.42		5.00%	(17,058)
48600	Communication Equipment	SQ-15	0%	6.67%	650,127.45		5.00%	(10,857)
48820	Houses	R3-40	-10%	2.89%	474,681.26		2.83%	(285)
					204,822,581.02			(1,870,583.68)

	As Filed	Using 2008/2009 Approved Depreciation Parameters	Using 2013/2015 Proposed Depreciation Parameters - No Net Salvage
2013			
Revenue Requirement	54,956	52,885	52,239
Rate Base	72,329	73,078	73,312
Return on Rate Base	5,308	5,364	5,382
2014			
Revenue Requirement	58,707	56,643	55,988
Rate Base	86,063	88,354	89,075
Return on Rate Base	6,255	6,420	6,473
2015			
Revenue Requirement	61,187	58,880	58,343
Rate Base	96,812	100,830	102,028
Return on Rate Base	7,003	7,292	7,378

UCG-YECL-24

Reference: May 27, 2013 Application, Section 7, Attachment 2

Mr. Kennedy states that "*many depreciation studies completed by Gannett Fleming have developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal.*"

Request:

(a) Please identify utilities comparable to YECL that have been allowed to include net salvage estimates within their current depreciation rates.

(b) Please provide details of regulator decisions related to the Gannett Fleming's proposed provisions relating to the recovery of costs of removal.

(c) Mr. Kennedy notes that Gannett Fleming developed separate provisions relating to the recovery of original cost of investment and for the recovery of costs of removal for Enbridge Consumers Gas in a 2012 Application to the Ontario Energy Board. How does this compare to Enbridge's application filed in June 2013 (EB-2012-0459) to change depreciation rates to reduce the annual amount for future site restoration costs and to implement a rate rider to return to ratepayers over a 5 year period more than $250 million previously over-collected in depreciation rates for site restoration costs and explain why Gannett's previously recommended depreciation rates were too high?

(d) Other than Enbridge, is Mr. Kennedy aware of any other utility that has had to refund over-collections of site recovery costs to ratepayers?

Response:

(a) A listing of utilities (that Yukon Electrical and Mr. Kennedy are aware of) that include net salvage within their depreciation rates is provided below:

- ENMAX Power Corporation (AUC Decision 2009-084)
- FortisAlberta Inc. (AUC Decision 2011-509)

- ATCO Electric (AUC Decision 2011-134)
- Manitoba Hydro (through 2014) (Manitoba PUB Order 43/13)
- Nova Scotia Power (Decision #NSUARB-NSPI-P-891)
- Newfoundland Power Inc. (Order No. P.U.13 (2013)
- Northland Utilities (NWT) Limited (PUB Decision 17-2011)
- Northland Utilities (Yellowknife) Ltd (PUB Decision 13-2011)

While the above listing is specific to electric distribution systems, the following is a list of other regulated Canadian utilities that include net salvage in the depreciation rate calculations:

- FortisBC Energy Inc. (BCUC Application 3698627)
- AltaLink LP (AUC Decision 2011-453)
- ATCO Gas (AUC Decision 2011-450)
- AltaGas Utilities Inc. (AUC Decision 2012-091)
- SaskEnergy Inc. (2007 Depreciation Study filing)
- CentraGas Manitoba (through 2014) (2012/13 and 2013/14 General Rate Application)
- Enbridge Gas Distribution (OEB Decision EB 2011-0345)
- Union Gas (OEB Decision EB-2007-0606)
- Gaz Metro (La Regie de L'Energie Decision R-3752-2011)
- Gazifere (La Regie de L'Energie Decision R-3724-2010)
- TransCanada Pipelines (NEB Decision RH-003-2011)

(b) Gannett Fleming does not understand what is meant by "provide details of regulator decisions." Please refer to part (a) for references to the applicable applications or Decisions. Many of these utilities have been allowed to include net salvage estimates in their depreciation rates for an extended period of time and as such, it would be difficult to provide details of the decision that first approved that treatment with a reasonable amount of effort and in the time allowed to respond to these information requests.

(c) This request is asking for specific comment on an application that is currently before the Ontario Energy Board for which Mr. Kennedy has been retained by Enbridge Consumers Gas to provide expert opinion. Mr. Kennedy is contractually precluded from disclosing any information with regard to the Enbridge Consumers Gas depreciation position that is not yet on the public record before the Ontario Energy Board. As such, Mr. Kennedy cannot comment on the reasons for the current over-depreciation position to any extent beyond that disclosed in the June 2013 Enbridge application (Application EB-2012-0459).

(d) True-ups of Accumulated Depreciation variances are part of virtually all depreciation studies conducted in Canada and most studies conducted throughout North America. The true-ups are often embedded in a remaining life calculation (where the net book value as adjusted for salvage is recovered over an estimated remaining life) or through a specific true up calculation (as is done in most Alberta studies and in this current Yukon Electrical application). These true-ups are required due to a number of factors, including variances caused by net salvage estimates being different than actual costs of retirement of assets.

Mr. Kennedy is not aware of any circumstances similar to the Enbridge Consumers Gas circumstance.

UCG-YECL-25

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 18

Mr. Kennedy states that "*investor-owned utilities generally all seek to incorporate the recovery of costs of removal in their revenue requirements through depreciation expense."*

Request:

Please provide details of any utilities that either do not recover costs of removal through depreciation rates or use another mechanism to recover these costs.

Response:

Mr. Kennedy is aware of the following Canadian utilities that use an alternative mechanism for the recovery of costs of retirement:

- BC Hydro – Was ordered by the BCUC to draw down their current FRSR fund and then to expense costs of retirement in year of occurrence after the fund is drawn down to zero.

- FortisBC Inc. – Do not include any costs of removal in the depreciation calculations, but charge actual costs of removal to the accumulated depreciation account and recover the accumulated depreciation variance caused by this practice over the composite remaining life of each account.

- SaskPower – Charges costs of retirement to income (and to the revenue requirement) in the year of occurrence.

- Manitoba Hydro – Is recovering net salvage in the depreciation rates over its current test period, but has indicated that in future test years when IFRS is implemented the net salvage will be recovered in year of occurrence.

- Centra Gas Manitoba – Is recovering net salvage in the depreciation rates over their current test period, but have indicated that in future test years when IFRS is implemented the net salvage will be recovered in year of occurrence.

- Ontario Power Generation – Expenses the costs of retirement in year of occurrence (and to the revenue requirement)

- Hydro One – Expenses the costs of retirement in year of occurrence (and to the revenue requirement)

- New Brunswick Power – Distribution and Transmission assets – Does not include any costs of retirement in the depreciation calculations, but charges actual costs of retirement to the accumulated depreciation account and recovers the accumulated depreciation variance caused by this practice over the composite remaining life of each account.

- New Brunswick Power – Generation Assets – Expenses the costs of retirement in year of occurrence (and to the revenue requirement).

- Nalcor – Newfoundland and Labrador Hydro – Expenses the costs of retirement in year of occurrence (and to the revenue requirement).

- Qulliq Power Corporation - Expenses the costs of retirement in the year of occurrence.

UCG-YECL-26

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 18

Mr. Kennedy states that "*While investor-owned utilities will often attempt to avoid differences in the regulated ledgers versus the financial disclosure ledgers, I have noted that there is a greater tolerance to reconcile these differences.*"

Request:

Please provide details of any utilities that do have differences in the regulated ledgers versus the financial disclosure ledgers.

Response:

Mr. Kennedy notes that virtually all regulated utilities will have some differences between the accounting ledgers and the regulated accounting ledgers. However, it is Mr. Kennedy's experience that investor-owned utilities have a larger number of variances caused by other non-depreciation factors and will have an increased number of regulatory deferral accounts or will maintain completely separate ledgers. This has become more apparent as regulated utilities have adopted differing accounting standards (IFRS versus USGAAP, etc.).

With specific regard to depreciation practices, Mr. Kennedy is aware of the following utilities that have indicated a willingness to maintain an increased number of deferral accounts or separate depreciation related accounting ledgers:

- FortisBC Energy Inc.;
- FortisBC Inc.;
- ATCO Electric;
- ATCO Gas;
- ATCO Pipelines;
- FortisAlberta;
- AltaLink LP;
- AltaGas;
- ENMAX Power Corporation;
- Enbridge Consumers Gas;

- Union Gas;
- Newfoundland Power;
- NTPC;
- Northland Utilities (NWT) Ltd;
- Northland Utilities (Yellowknife) Limited; and
- TransCanada Pipelines.

UCG-YECL-27

Reference: May 27, 2013 Application, Section 7, Attachment 2, page 19

Mr. Kennedy states that "*it is my experience that ownership does make a difference in the regulatory and depreciation principles as applied by regulatory authorities throughout Canada.*"

May 27, 2013 Application, Section 7, Attachment 2, page 20

Mr. Kennedy states that "*Canadian regulatory practice over the period since the issuance of YUB Order 2009-2 demonstrates an increased tolerance of allowing crown-owned utilities to follow differing practices with regard to net salvage than investor-owned utilities within the same jurisdiction."*

Request:

(a) Please identify when the Yukon Utilities Board has applied regulatory and depreciation principles differently to YECL and YEC.

(b) Other than in Newfoundland, has any Canadian regulator allowed a differing practice regarding collection of net salvage estimates by a crown-owned utility as compared to an investor-owned utility that deal with the same form of energy?

(c) Does Mr. Kennedy consider Ontario's crown-owned Ontario Power Generation comparable to the gas distribution utilities in Ontario?

(d) Please provide details of where Canadian regulatory practice over the period since the issuance of YUB Order 2009-2 demonstrates an increased tolerance of allowing crown-owned utilities to follow differing practices with regard to net salvage than investor-owned utilities within the same jurisdiction.

(e) Please identify where YECL's circumstances have changed since the February 2009 issuance of Order 2009-2 that would require the reinstatement of negative salvage amounts in depreciation rates.

Response:

(a) Yukon Electrical is aware of two differences between YEC and Yukon Electrical in regards to regulatory and depreciation principles. One notable difference is with respect to the hearing costs reserve. In the case of Yukon Energy, it did not have a Hearing Cost Reserve until its most recent 2012-2013 GRA. Yukon Electrical, however, was ordered to treat its hearing costs as part of a Hearing Cost Reserve since the 1996-1997 GRA. With regard to depreciation practices, it is noted that in YUB Decision 2009-02, the use of Equal Life Group (ELG) procedure was specifically approved for use by Yukon Electrical, despite the argument of YEC which pointed out that they were using the Average Service Life procedure. As such, there is a significant difference in the approved depreciation practices for Yukon Electrical as compared to YEC.

(b) In British Columbia, the BCUC has ordered a differing practice for BC Hydro as compared to the allowed practice for the electric operations of FortisBC Energy Inc. as described in response to UCG-YECL-25.

It is noted that there are only a few circumstances where there is a mix of crown-owned corporations and private investor-owned utilities within the same province in the same energy sector. However, a broader look across Canadian jurisdictions provides a much clearer view of the differences in approaches of crown and investor-owned utilities. Additionally, in a number of provinces where crown and investor-owned utilities exist across varying energy sectors, the differences in approaches are also more apparent.

(c) Mr. Kennedy notes that there are obvious large differences between large hydro and nuclear generation and natural gas distribution utilities. However, there are a number of regulatory similarities between Ontario Power Generation and the natural gas distribution utilities in Ontario as follows:

- Both are regulated by the Ontario Energy Board;
- Both will face very large expenditures related to future removal of facilities;
- Both have a mix of long lived assets and shorter lived technology-based assets.

(d) Please refer to the additional evidence of Larry Edwin Kennedy at pages 6 through 10, and pages 14 through 18 included in Yukon Electrical's Application.

(e) Please refer to the response to information request YEC-YECL-12(a).

UCG-YECL-28

Reference: May 27, 2013 Application, page 8-4

YECL states "*Yukon Electrical, as detailed in the expert evidence prepared by Kathy McShane for the 2008-2009 GRA, shares similar business risk to its affiliate, Northland Utilities (Yellowknife) Limited."*

May 27, 2013 Application, page 8-5

YECL states "*Yukon Electrical continues to face greater business risk than the average Canadian or British Columbia utility.*"

Request:

(a) Please provide the evidence upon which the statement on page 8-5 is based and the qualifications of the individual that undertook this analysis.

(b) With respect to the comparison of YECL relative to the Northland utilities, what evidence exists that Northland is comparable to YECL's current operations and operating environment?

Response:

(a) For purposes of this Application, Yukon Electrical continues to rely on the 2008-2009 expert evidence from Kathy McShane that concluded Yukon Electrical's business risk suggested an equity ratio of 45% - 55% and financial metrics suggested an equity ratio in the upper end of the 47.5% - 52.5% range. Please refer to YUB-YECL-33(b) Attachment 1 for a copy of this expert evidence. To address the issue of the period of time between 2008 and today, Yukon Electrical management completed a review of its business risks in the 2013-2015 test period as compared to the 2008-2009 test period. While most business risks continue to remain consistent with those assessed in 2008, Yukon Electrical has noted a number of areas in market demand and operational costs where business risk has increased modestly since 2008. Please refer to YUB-YECL-31 for further details on its business risk in 2013 as compared to 2008.

(b) For purposes of regulatory efficiency, Yukon Electrical is relying on the evidence provided in the 2008-2009 GRA that stated Yukon Electrical has comparable business risk to Northland as well as Yukon Electrical management's conclusion as part of this Application that nothing material has changed in the period between 2008 and 2013 that would indicate a significant change in the relative risk between Yukon Electrical and Northland Utilities. Please refer to YUB-YECL-31 where Yukon Electrical provides further details on its business risk in 2013 as compared to 2008 as well as YUB-YECL-33(b) where Yukon Electrical provides statistics comparing Yukon Electrical with the Northland companies in 2012.

UCG-YECL-29

Reference: YUB Order 2013-01 - Reasons for Decision, March 25, 2013 Application,

The YUB states on page 50 "*In summary, the Board has determined that the simplified approach is the approach to be used in determining the ROE for utilities under its jurisdiction. The simplified approach was based on the precedence of the BCUC formulaic model. In this proceeding, since recent results of the BCUC model are not available, YEC can use the benchmark results from the AUC model. Therefore, the Board directs YEC in its compliance filing to use an ROE of 8.25 percent."*

May 27, 2013 Application, page 8-3

YECL states that on May 10, 2013, the BCUC issued Order G-75-13 addressing a number of matters including (1) a generic benchmark ROE of 8.75% effective January 1, 2013; (2) a benchmark common equity ratio of 38.5% effective January 1, 2013; and (3) an Automatic Adjustment Mechanism formula for annually setting the ROE starting January 1, 2014. YECL also notes that a second phase of the BCUC GCOC proceeding is now underway which will determine an appropriate risk premium and deemed capital structure for British Columbia utilities that differ in risk from the benchmark utility.

O.I.C. 1995/090

Normal return on equity

2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

Request:

(a) Please confirm YECL's understanding that OIC 1995/90 requires that there only be 0.5% difference between the return on equity allowed to be recovered in rates charged by YECL and YEC.

(b) Please confirm YECL's understanding that the YUB has allowed YEC to incorporate a return on equity of 8.25% into its 2013 rates.

Response:

(a) Not confirmed. OIC 1995/90, as amended by OIC 1998/32, states the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on the equity used to finance their rate base. In the case of Yukon Energy, the Board determined a fair return of 8.75% for each of 2012 and 2013 in Decision 2013-01. This return was based on Yukon Energy's 2012-2013 GRA and the associated evidentiary record. Thereafter, subject to subsection (2) of OIC 1995/90, the Board determined Yukon Energy's awarded return to be 8.25% (8.75% - 0.5%) for each of 2012 and 2013. In the case of Yukon Electrical's 2013-2015 GRA, the Board will award a fair return on the equity used to finance Yukon Electrical's rate base based on Yukon Electrical's Application and the associated evidentiary record. Subsection (2) of OIC 1995/90 is not applicable to Yukon Electrical.

(b) Confirmed.

UCG-YECL-30

Reference: May 27, 2013 Application, page 8-6

YECL states "*Given Yukon Electrical shares similar business risks as compared to its affiliates in the Northwest Territories as well as the increase to the common equity ratio benchmark in British Columbia, Yukon Electrical is requesting to increase its common equity ratio from the current level of 40% to 44% for each of 2013, 2014 and 2015.*"

Request:

(a) Please provide the evidence upon which the statement on page 8-6 is based and the qualifications of the individual that undertook this analysis.

(b) Please explain why YECL is applying to increase its equity ratio to 44% when the generic benchmark ROE of 8.75% was established by the BCUC for a utility having a 38% equity ratio.

(c) Please indicate all cases in the last 5 years where YECL has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions. Please provide details.

(d) Is YECL planning to raise any capital to finance investment growth in the 2013-2015 test period?

(e) Please indicate whether YECL's ability to earn its allowed ROE will different at the current 40% common equity ratio as compared to proposed 44% common equity ratio.

(f) Please confirm YECL's understanding that reviews of capital structure and associated returns are typically only undertaken when there is a significant change in financial, business or corporate fundamentals. Please provide an exhaustive list of the significant changes in financial, business or corporate fundamentals that is driving YECL's proposed change in the equity component of rate base.

(g) Please provide all available Canadian comparables to YECL showing equity thickness, investment ratings, financial risk indicators and financial ratios (especially interest coverage).

(h) Please provide a table that reflects the actual annual ROE earned by YECL for 2009 through 2012.

(i) Please provide a table that reflects normalized actual annual ROE earned by YECL that is based on normalized volumes for 2009 through 2012.

(j) Please provide details of the change in revenue requirement for 2013, 2014 and 2015 by keeping the equity ratio at 40% and allowing a return on equity of 8.75%.

Response:

(a) Please refer to YUB-YECL-33(b) Attachment 1 for the Kathy McShane evidence from the 2008-2009 GRA. On page 22, Ms. McShane concludes Yukon Electrical:

i. Is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada

ii. Is of higher than average business risk within the spectrum of Canadian utilities and,

iii. Is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited.

An overview of Yukon Electrical's business risk as compared to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited, is as follows:

Market demand risk – both utilities are small in relative terms, serve similar northern based economies, have a concentration of sales in a relative small geographic area, must compete with alternative energy sources and have variations in sales due to weather.

Supply and physical (operating) risk – both utilities are supplied by crown owned utilities with Yukon Electrical, however, supplying approximately nine percent of its own supply requirements through Fish Lake hydro and its diesel plants. Both utilities' operations are subject to similar severe weather climates.

Regulatory risk – Yukon Electrical and Northland each are regulated by northern based public utilities boards, The Yukon Utilities Board and The NWT Public Utilities Board, respectively.

(b) Please refer to YUB-YECL-33(b) for the explanation as to why Yukon Electrical is applying for a common equity ratio to 44% as compared to the BCUC GCOC benchmark common equity ratio of 38.5%.

(c) Due to Yukon Electrical's subsidiary relationship with CU Inc., there have been no cases in the last 5 years where Yukon Electrical has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions.

(d) Yes.

(e) Under the stand alone principle, which encompasses the notion that the cost of capital incurred by Yukon Electrical should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters, Yukon Electrical would have difficulty accessing capital markets with a 40% common equity ratio which, in turn, would impact its ability to earn its allowed ROE.

(f) Not confirmed. Cost of capital reviews may be associated with a material change in market conditions or fundamental risks of the regulated entity, but may also occur periodically due to a pre-arranged schedule or the expiry of existing arrangements. Yukon Electrical's capital structure and ROE are being reviewed in this proceeding as part of its overall General Rate Application for 2013 – 2015. Yukon Electrical, in accordance with direction from the Board, has linked its capital structure and ROE to other jurisdictions to minimize costs and avoid expensive litigation of what are very complex matters. For the requested change in capital structure, please refer to part (b) above and Yukon Electrical's Application on page 8-6.

(g) For purposes of this Application and consistent with Yukon Board direction, Yukon Electrical's approach has been to efficiently link its ROE and common equity ratios to the BCUC GCOC as well to what has been approved by the Northwest Territories Public Utilities Board for the Northland companies, which share similar business risks with Yukon Electrical.

Further to the above, since 2008 the BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

In addition, as detailed in WL-YECL-17(b) Attachment 1, Yukon Electrical's forecast 2013 – 2015 financial credit metrics of FFO/Debt (20%) and FFO Interest Coverage (average of 4.36X) continue to fall within the ranges in Table 7 of the McShane evidence.

(h) The following ROEs for 2009-2012 are detailed on Schedule 8.1 of Yukon Electrical's Application:

2008: 7.03%

2009: 11.35%

2010: 10.54%

2011: 10.74%

2012: 10.18%

(i) Yukon Electrical's ROE based on normalized sales volumes for 2009 through 2012 would have been:

2009: 11.07%

2010: 11.37%

2011: 10.57%

2012: 9.41%

(j) Keeping the equity ratio at 40% and allowing a return on equity of 8.75% would reduce Yukon Electrical's revenue requirement by $440,000 (0.8%) for 2013, $542,000 (0.9%) for 2014 and $586,000 (1.0%) for 2015.

UCG-YECL-31

Reference: May 27, 2013 Application, page 8-6

Request:

(a) Please provide details of the long term debt YECL intends to issue during the 2013-2015 test period.

(b) Please provide details of the rates associated with any long, medium or short term debt issued by YECL over the last 10 years.

(c) Please compare the rates from part (b) with the Long Canada Bond Rates for that same period.

(d) Since YECL has proposed a deferral mechanism related to the return on equity, please provide your opinion on whether this same concept should apply to the issuance of debt which is largely not in the control of YECL.

Response:

(a) Please refer to UCG-YECL-31(a) Attachment 1.

(b) Please refer to UCG-YECL-31(b) Attachment 1.

(c) Please refer to UCG-YECL-31(b) Attachment 1.

(d) Yukon Electrical prepared its forecast of future rates using the best information available at the time of its application. Yukon Electrical has not applied for, nor does it favour, a change in approach with respect to the treatment of the cost of new debt.

The Yukon Electrical Company Limited
Long Term Debt Forecast to Be Issued 2013-2015

Series	Amount ($)	Coupon Rate	Effective Cost Rate *
Y	1,400,000	4.30%	4.35%
Z	13,700,000	5.00%	5.05%
AA	-	5.75%	5.80%

* The effective cost rate includes costs to issue debt.

Series	Issue Date	Yukon Electrical Rate	Long Canada Bond Rate
O	2004-01-23	5.47%	4.822%
P	2004-11-18	5.16%	4.546%
Q	2005-11-21	5.23%	4.293%
R	2006-11-20	5.07%	4.122%
S	2008-05-26	5.61%	4.083%
T	2008-05-26	5.62%	4.100%
U	2009-03-06	6.28%	3.565%
V	2009-03-06	6.55%	3.750%
W	2011-10-24	4.58%	2.943%
X	2012-11-14	3.89%	2.357%

* The Yukon Electrical Rate includes costs to issue debt.

UCG-YECL-32

Reference: May 27, 2013 Application, page 8-7

Request:

Please provide a copy of the table that appears at the top of page 8-7 with actual data from 2008 through 2012. Please provide all related source documents for the updated table.

Response:

The following tables summarize actual debenture issues by Yukon Electrical from 2008 through 2012:

	2008		2009	
Issue Date	May 26, 2008	May 26, 2008	Mar 6, 2009	Mar 6, 2009
Maturity Date	May 26, 2028	May 26, 2038	Mar 6, 2024	Mar 7, 2039
Long Canada Bond	4.083%	4.100%	3.565%	3.750%
Issue Spread	1.527%	1.520%	2.715%	2.800%
Debenture Rate	5.61%	5.62%	6.28%	6.55%

	2011	2012
Issue Date	Oct 24, 2011	Nov 14, 2012
Maturity Date	Oct 24, 2041	Nov 14, 2052
Long Canada Bond	2.943%	2.357%
Issue Spread	1.637%	1.533%
Debenture Rate	4.58%	3.89%

UCG-YECL-33

Reference: May 27, 2013 Application, page 8-7

YECL states that "*The no cost capital included in this Application relates to the balances for deferred pensions including other post employment benefit plans ("OPEB") as well as the reserve for injuries and damages.*"

Request:

(a) Please provide an explanation of the proposal being made by YECL regarding the section of the Application related to no cost capital.

(b) Please confirm whether YECL is earning any return on no cost capital and where this return is identified in the Application.

Response:

(a) Consistent with its last GRA and Board Order 2009-2, Yukon Electrical is proposing to continue to account for both pension and OPEB on the cash basis in the test period. The cash basis results in the charges equaling the forecast cash payments for each year.

For the reserve for injuries and damages, Yukon Electrical is proposing to amortize the balance of ($69,000) at the end of 2012 as well as the forecast annual charges for the test period over the three test years to bring the reserve balance to $0 as of December 31, 2015. The forecast annual charge of $100,000 for each test year is based on the average of the actual annual charges for 2010-2012.

(b) Yukon Electrical does not earn a return on no cost capital as detailed on Schedule 8.1 of its Application.

UCG-YECL-34

Reference: May 27, 2013 Application, page 8-10, Schedule 8.8

YECL states that it "*is using a deferral account to flow through to customers the costs associated with filing its GRAs. See Schedule 8.9 for a breakdown of the Phase I and Phase II costs forecast for 2013-2015. No rate case write-off is required from 2013-2015 to bring the overall deferred rate case balance to zero by the end of the test period*."

Request:

(a) Please confirm that the balance in the rate case costs deferral account was in a credit position (i.e., there had been an over-collection of costs) at the end of every year since 2008.

(b) Please confirm that YECL has already recovered the costs that it has forecast will be incurred in the current general rates application proceeding as well as the Phase II proceeding anticipated to be conducted in 2014.

(c) Please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs expected to be incurred by YECL in respect the current rates proceeding and a future rates proceeding prior to having them recovered in rates.

Response:

(a) Confirmed.

(b) Confirmed.

(c) Yukon Electrical only records approved costs into its rate case reserve. For purposes of the test period 2013–2015, Yukon Electrical has provided a forecast of what will be approved for regulatory costs through to the end of 2015. (Please refer to Schedule 8.8 line 23 and Schedule 8.9.) Actual approved costs for this period will be trued-up as part of Yukon Electrical's next GRA.

UCG-YECL-35

Reference: May 27, 2013 Application, page 8-10, Schedule 8.8

Watson Lake Bi-Fuel Project Study Costs

Request:

Please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs incurred or to be incurred by YECL in respect to the deferred study costs related to the Watson Lake Bi-Fuel Project prior to having them recovered in rates.

Response:

Yukon Electrical is providing the YUB and interveners an opportunity to test the prudence of the study costs related to the Watson Lake Bi-Fuel Project prior to having them recovered in rates as part of this proceeding.

Please refer to Table UCG-YECL-35 for the summary of project study costs related to the Watson Lake Bi-Fuel Project.

Table UCG-YECL-35: Study Costs for the Watson Lake Bi-Fuel Project

Total Study Expenses Breakdown

	2012	2013	
Site Survey	$ 6,800		
3rd Party Feasibility Engineering	$ 27,500	$ 25,000	
3rd Party Permits & Regulations Assistance	$ 16,700	$ 91,300	
Education and Outreach	$ 5,000	$ 25,000	
Internal Time & Expenses	$ 24,700	$	
Total	$ 80,700	$ 141,300	
Total			**$ 222,000**

The areas covered by the study are as follows:

- Project Management
  - Understanding and evaluating costs to develop a budget
  - Identify Risk ledger
  - Identifying and understanding stakeholder requirements
- Legal
  - Understanding legal contracts required
- Financial
  - Understanding economic parameters: diesel, natural gas, liquefaction rates, transportation costs and distance implications, LNG sourcing options, equipment options
  - Developing and evaluating an economic model
- Procurement
  - Understanding project requirements to be supplied by 3rd parties
- Design
  - Evaluating technical feasibility of the project:
    - Bi-fuel equipment
    - Power plant upgrade requirements
    - LNG supply chain (supply and transportation)
    - LNG facility development (vaporization system options and impoundment options)
  - Siting study – evaluating proximity to other power plant facilities, neighbors, environmental considerations
  - Emissions studies – literature review on bi-fuel system emissions compared with modeled Watson Lake Power Plant diesel combustion (status quo) emissions
  - Life Cycle Analysis comparing status quo to bi-fuel operations – production well-head (oil versus natural gas) through product production (diesel versus LNG), transportation, and use at power plant

- Issues identification for operations at -50 degree C temperatures – sensors, valves, equipment
- Risk Analysis of design (thermal radiation and dispersion modeling)
- Identify HAZOP development and exercise requirements

· Permitting

- Identify and understand implications of all federal, territorial and provincial (LNG source), and municipal acts and regulations that apply
- Identify and understand all codes and standards which apply
- Outline approvals need related to regulations
- Prepare information for YESAB submission
- Investigate Transportation of Dangerous Goods requirements including emergency response requirements

· Operations

- Investigate Emergency Response Planning specific to power plant infrastructure and Environment Canada Environmental Emergency Plan (E2Plan)
- Consultation with territorial and municipal first responders
- Logistics planning – internal and coordination with external suppliers
- Maintenance planning – internal and coordination with external suppliers

· Training

- Identify LNG Spill and Fire Suppression training requirements and current training locations
- Investigate LNG on and off loading of tanker and on-site operations

· Communications

- Develop communication related to natural gas, liquefied natural gas, risks and safety, stakeholder outreach, coordination with authorities having jurisdiction
- Carrying out communication plan – meetings with authorities having jurisdiction, stakeholder (local community and first nations) consultation

UCG-YECL-36

Reference: May 27, 2013 Application, page 8-10, Schedule 8.8

YECL states "*As part of its 2008-2009 GRA, Yukon Electrical forecast generation in the test period assuming the connection of Pelly Crossing to the main grid effective November 1, 2008. As the timing of commencement of the service was uncertain and the costs associated a change in the assumed connection date were material, Yukon Electrical received approval in Board Order 2009-2 for a deferral account for the incremental costs associated with any changes that resulted from reliance on the assumption. Pelly Crossing was connected to the grid on November 27, 2008, resulting in incremental costs of $33,000 which are included on Schedule 8.8. Yukon Electrical is proposing to collect $11,000 each year over the period 2013-2015 resulting in a zero balance of the end of the test period.*"

Request:

Given the YUB's rejection of YEC's proposed planning cost accounting policy in its Order 2013-01 (page 83), please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs incurred by YECL in respect to the deferred costs related to Pelly Crossing prior to having them recovered in rates.

Response:

In Board Order 2009-2, Yukon Electrical received approval for a deferral account for fuel costs associated with Pelly Crossing being connected to the grid before or after November 1, 2008. Pelly Crossing was connected to the grid on November 27, 2008, resulting in incremental fuel costs of $33,000. Please refer to UCG-YECL-36 Attachment 1 for a copy of the calculation.

The Yukon Electrical Company Limited
Calculation of Pelly Crossing Deferral

Forecast Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008 (per page 4-3 of the 2008-2009 GRA)		500	(a)
Actual Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		63,098	(b)
Incremental Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		62,598	(c) = (b) - (a)
Forecast Diesel Rate (per page 4-3 of the 2008-2009 GRA)	$	0.8933	(d)
Incremental Cost of Diesel Used at Pelly Crossing Subsequent to November 1, 2008	$	55,919	(e) = (c) * (d)
Prorate for Number of Days in Which Pelly Crossing Connection to the Grid Was Delayed	$	48,463	(f) = (e) x 26/30
Incremental Use of Diesel Fuel in litres at Pelly Crossing Subsequent to November 1, 2008		62,598	(c)
Forecast Heat Rate (per page 4-3 of the 2008-2009 GRA)		3.62	(g)
Incremental kwH Generated Using Diesel at Pelly Crossing		226,605	(h) = (c) * (f)
Forecast Purchased Power Rate (per page 4-3 of the 2008-2009 GRA)	$	0.0684	(i)
Incremental Savings on Purchased Power for Pelly Crossing Subsequent to November 1, 2008	$	15,500	(j)
Net Incremental Cost to Yukon Electrical Associated With Delay in Connection of Pelly Crossing to the Grid	$	32,963	(e) - (j)

UCG-YECL-37

Reference: May 27, 2013 Application, page 8-11

YECL states "*Yukon Electrical will incur $20,000 worth of consulting costs to study the feasibility of using wind to generate power in the Burwash and Destruction Bay area. Yukon Electrical is proposing to collect this amount from customers over the period 2013-2015, resulting in a zero balance of the end of the test period.*"

Request:

Given the YUB's rejection of YEC's proposed planning cost accounting policy in its Order 2013-01 (page 83), please explain where YECL has provided the YUB and intervenors an opportunity to test the prudence of all costs incurred by YECL in respect the proposed feasibility study costs prior to having them recovered in rates.

Response:

Yukon Electrical is providing the Board and interveners an opportunity to test the prudence of costs incurred in respect of the feasibility study as part of this proceeding.

The costs incurred were to investigate the feasibility in advancing the development of a wind-diesel integration project into the Destruction Bay and Burwash Landing electrical grid with the objective of incorporating renewable electricity to reduce the consumption of diesel and its emissions. The challenge addressed by the study was to integrate cost effective renewable energy into an isolated diesel-dependent community in Northern Canada.

The work utilized consulting services to update and refine previous pre-feasibility studies that were prepared several years earlier. The first phase of the work included an update of the wind energy production estimates based on up-to-date wind generation technology, modeling of diesel energy displacement at different levels of installed wind generation capacity and capital cost estimates. The final product was a pre-feasibility report on the potential wind energy project.

The results of the study indicate that it is possible to overcome the technical challenges related to the project at an approximate LCOE of 50 cents/kWh.

UCG-YECL-38

Reference: May 27, 2013 Application, page 8-12

YECL states "*To determine the working capital for the 2013-2015 test period, Yukon Electrical completed a review of the components of each of the items in necessary working capital to ensure that the nature of the revenue/expenses included in each category had not changed materially since the 2008 lead/lag study was conducted and filed in Yukon Electrical's 2008-2009 GRA. Based on this review, the only component in the lead lag study that required an update was salary and wages lead/lag days as a result of Yukon Electrical moving to standard industry practice of bi-weekly payroll processing on January 1, 2010 with a one week payment lag.*"

Request:

Please provide all details of the lead/lag study review that verifies that only one component needed to be changed. Please provide all schedules in Excel format.

Response:

Based on Yukon Electrical management's knowledge of the operations, a review of each component was conducted and it was determined that there was no material changes in the types of revenues and expenses or in the payment terms, other than the change in the timing of payroll processing as discussed on page 8-12 of the Application. As a result, Yukon Electrical did not conduct a full lead/lag study for the purpose of this Application as it was determined to be unnecessary.

UCG-YECL-39

Reference: May 27, 2013 Application, Schedule 8.5

Request:

(a) Please confirm that YECL's actual rate base for 2008 and 2009 was lower in each year than was approved in the last general rates application review.

(b) Since rates for 2008 through 2012 were based in part on a return on rate base that was in excess of what would have been earned on actual rate base, please provide a calculation of the excess return incorporated in rates for 2008 through 2012.

Response:

(a) Confirmed. Yukon Electrical's rate base was $144,000 (0.3%) lower for 2008 and $362,000 (0.7%) lower for 2009 than was approved in its last GRA.

(b) Please refer to UCG-YECL-39(b) Attachment 1 for the calculation of return on rate base included in rates and the return on rate base that would have been earned on actual rate base for 2008 and 2009. Based solely on the differences between approved rate base and actual rate base, the higher than forecast return incorporated into rates was:

Year	Return on Rate Base Included in Rates ($000)	Return on Rate Base Based on Actual Rate Base ($000)	Excess Return Included in Rates ($000)
2008	3,519	3,508	11
2009	3,675	3,650	25

For each of 2010, 2011 and 2012, Yukon Electrical's actual rate base was higher than approved for 2009. As Yukon Electrical remained on 2009 rates for each of those years, there is a deficiency in the return on rate base that would have been earned on actual rate base as compared to the return on rate base included in rates.

The Yukon Electrical Company Limited
Return on Rate Base

	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
2008 GRA Approved				
Long-Term Debt	59.11%	27,244	6.87%	1,870
Common Stock	39.41%	18,162	9.08%	1,649
No Cost Capital	1.49%	685	0.00%	-
Total	100.00%	46,091	7.63%	3,519
2008 Based on Actual Rate Base				
Long-Term Debt	59.11%	27,158	6.87%	1,864
Common Stock	39.41%	18,105	9.08%	1,644
No Cost Capital	1.49%	683	0.00%	-
Total	100.00%	45,946	7.63%	3,508
2009 GRA Approved				
Long-Term Debt	59.17%	29,276	6.60%	1,934
Common Stock	39.45%	19,517	8.92%	1,741
No Cost Capital	1.38%	684	0.00%	-
Total	100.00%	49,478	7.43%	3,675
2009 Based on Actual Rate Base				
Long-Term Debt	59.17%	29,062	6.60%	1,920
Common Stock	39.45%	19,375	8.93%	1,730
No Cost Capital	1.38%	679	0.00%	-
Total	100.00%	49,116	7.43%	3,650

UCG-YECL-40

Reference: May 27, 2013 Application, page 9-2

YECL states that it "*tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. Additionally, Yukon Electrical reviews outages that may be attributed to system deficiencies.*"

Request:

(a) Please provide all reports prepared since 2008 related to YECL's ongoing tracking of distribution system performance and outages.

(b) Please identify the specific distribution system performance improvements and the related impact on revenue requirement that have resulted from capital expenditures since 2008.

Response:

(a) Please refer to UCG-YECL-40(a) Attachment 1.

(b) Please refer to Schedule 9.1, Line 11 for total Distribution Improvement projects for the period 2008-2015. Please refer to pages 9-5 through 9-67 of the Application for descriptions of all Distribution Improvement projects over $100,000. Yukon Electrical does not track system performance on an individual capital project basis.

Yukon Electrical's sales in MWh have grown by 8.2% from 2008 to 2012 (from 292,647 MWh to 316,575 MWh). The associated increase in load would normally be expected to increase losses. However, Yukon Electrical's losses over the same period have actually remained flat, as show on line 4 of Schedule 3.2 in the Application. Therefore, Yukon Electrical believes the Distribution Improvement projects it has undertaken have been successful in preventing the level of losses from increasing as load has grown from 2008 to 2012.

The total value of Distribution Improvement projects completed from 2008-2012 was $15,493. These projects have impacted the return on rate base, depreciation and income taxes included in revenue requirement for 2013-2015.

Reliability Performance

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

Yukon Electrical's 2008 results (including and excluding loss of supply from Yukon Energy) are as follows:

	Including Loss of Supply From Yukon Energy	Excluding Loss of Supply From Yukon Energy
SAIFI	8.83	3.00
SAIDI	10.01	.12
CAIDI	1.13	.04
IOR	99.8857%	99.8129%

Reliability Performance

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

Yukon Electrical's 2009 results (including and excluding loss of supply from Yukon Energy) are as follows:

	Including Loss of Supply From Yukon Energy	Excluding Loss of Supply From Yukon Energy
SAIFI	8.00	2.43
SAIDI	5.52	2.52
CAIDI	.69	1.04
IOR	99.9366%	99.9712%

Reliability Performance

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

Yukon Electrical's 2009 results (including and excluding loss of supply from Yukon Energy) are as follows:

	Including Loss of Supply From Yukon Energy	Excluding Loss of Supply From Yukon Energy
SAIFI	3.98	1.49
SAIDI	2.95	1.57
CAIDI	.74	1.06
IOR	99.9664%	99.9821%

Reliability Performance

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

Yukon Electrical's 2009 results (including and excluding loss of supply from Yukon Energy) are as follows:

	Including Loss of Supply From Yukon Energy	Excluding Loss of Supply From Yukon Energy
SAIFI	6.15	2.11
SAIDI	7.16	2.65
CAIDI	1.16	1.26
IOR	99.91828%	99.96978%

Reliability Performance

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

Yukon Electrical's 2012 results (including and excluding loss of supply from Yukon Energy) are as follows:

	Including Loss of Supply From Yukon Energy	Excluding Loss of Supply From Yukon Energy
SAIFI	2.60	2.15
SAIDI	3.15	2.97
CAIDI	1.21	1.38
IOR	99.963%	99.966%

UCG-YECL-41

Reference: May 27, 2013 Application, page 9-4

YECL states "*A listing of the capital expenditures for 2008-2015 is provided in the following pages. For significant projects greater than $100,000, a description of the project is included. Business cases for all major capital projects ($500,000 or greater) are being filed with this Application as directed in Board Order 2009-2.*"

Board Order 2009-2, page 37

"*The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures.*"

Request:

(a) Please confirm that YECL considers "major capital projects" to only be those projects costing $500,000 or greater.

(b) Please provide references to YUB Orders in which Board defines what it believes to be the spending threshold for a major project for YECL.

(c) Does YECL believe that a utility with a $60 million rate base (such as YECL) should have the same expenditures threshold to define a major project as a utility with a $226 million rate base (such as YEC)?

Response:

(a) Confirmed.

(b) Yukon Electrical is not aware of any YUB Orders in which the Board defines what it believes to be the spending threshold for a major project for Yukon Electrical.

(c) Yukon Electrical believes it's reasonable to have a lower major project threshold than Yukon Energy. This is why it filed business cases for all capital projects $500,000 or greater as opposed to $1,000,000 or greater.

UCG-YECL-42

Reference: May 27, 2013 Application, page 9-5

YECL provides a listing of 5 projects plus 1 "Other Projects" which make up $853,000 in **2008 capital expenditures on generation plant projects**.

Board Order 2009-8, page 37

"*Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:*

- *descriptions of the project*
- *economic analysis including preliminary engineering estimates*
- *discussion of alternatives and how the chosen option was determined*
- *discussion of the risks of proceeding with the chosen alternative*
- *discussion of risks of not proceeding with the chosen alternative; and*
- *discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.*"

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in all of the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Generator End of Life Rebuild	$463,000
Haines Junction Plant Upgrades	$100,000
Pelly Crossing Tie into Transmission Grid	$ 92,500
Watson Lake Generator Upgrades and Fresh Air Intakes	$ 76,500
Destruction Bay Compton Protection Relay Replacement / Battery Charger Upgrade	$ 65,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Generator End of Life Rebuild	$463,000
Haines Junction Plant Upgrades	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2008 capital expenditures on generation plant projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on generation plant projects for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2003-2007 for generation plant projects was $696,000.

UCG-YECL-43

Reference: May 27, 2013 Application, pages 9-5 to 9-7

YECL provides a listing of 18 projects plus 1 "Other Projects less than $20,000" which make up $3,244,000 in **2008 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in all of the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,304,000
Mountain Air Subdivision	$ 317,000
Hamilton Boulevard Main Infrastructure Extension	$ 266,000
Yukon Government Whitehorse Copper Phase II	$ 262,000
Little Atlin Feeder Tap	$ 178,000
Stan McCowan Subdivision	$ 126,000
Land Rights	$ 100,000
Miscellaneous New U/G Services	$ 95,000
4th Ave and Strickland Condominiums	$ 92,000
Arkell Subdivision Infill	$ 78,000
Skookum Asphalt Plant	$ 61,000
Lot 16 Marwell Subdivision	$ 53,000
Connection of Minto Landing into Yukon Interconnected System	$ 47,000
General Drafting and Mapping	$ 46,000
New Customer Connection at Minto Crossing	$ 40,000
Whitehorse Cadet Camp Three Phase Service	$ 40,000
Carcross Tagish First Nation Carcross Line Rerouting	$ 32,000
Lot 10 Centennial Street	$ 28,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,304,000
Mountain Air Subdivision	$ 317,000
Hamilton Boulevard Main Infrastructure Extension	$ 266,000
Yukon Government Whitehorse Copper Phase II	$ 262,000
Little Atlin Feeder Tap	$ 178,000
Stan McCowan Subdivision	$ 126,000
Land Rights	$ 100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2008 capital expenditures on distribution new extensions projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on distribution new extensions projects for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2003-2007 for distribution new extensions projects were $2,209,000.

UCG-YECL-44

Reference: May 27, 2013 Application, pages 9-8 to 9-10

YECL provides a listing of 30 projects plus 1 "Other Projects less than $20,000" which make up $3,395,000 in **2008 capital expenditures on distribution improvement projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

4L311 Upgrade Distribution Lines Between 1st and 6th Avenue, Whitehorse	$439,000
Connect Pelly Crossing into Yukon Interconnected System	$435,000
Ketza Court Live Front Transformers Replacement	$346,000
5L628 Squanga Road Rebuild	$290,000
Right of Way Widening	$268,000
9L - Km 129 to Km 132 South Klondike Highway - Distribution Line Rebuild	$189,000
Hillcrest Subdivision Conversion	$ 93,000
System Upgrades Lot 1378/79 Range Road	$ 93,000
Miscellaneous Pole Replacements	$ 92,000
Cadet Camp Three Phase Service System Improvement	$ 83,000
9L Reliability Upgrade Squanga Lake Area	$ 77,000
Test and Treat Pole Program	$ 72,000
Tagish Bridge Conduit Replacement	$ 60,000
Little Atlin Lake Area 3 Phase Pole Upgrades	$ 60,000
Echo Lake Road Upgrade	$ 52,000
McIntyre Subdivision 34.5kV Upgrade	$ 47,000
Morley Bay Line Upgrade	$ 46,000
Birch Alley Upgrade	$ 45,000
Campbell Highway Relocation	$ 43,000
Carmacks Upper Bench Rerouting	$ 31,000
Paddlewheel Line Relocation	$ 30,000
Carmacks Planned Pole Replacements	$ 28,000
Porter Creek Regulator Upgrade	$ 26,000
Beaver Creek Planned Pole Replacements	$ 25,000
North Star Clearance Upgrade	$ 24,000
McIntyre Creek Pumphouse Upgrade	$ 23,000

McDonald Road to Centennial Road Upgrade	$ 23,000
Convert Spirit Lake to 14.4kV	$ 22,000
Marwell Subdivision Improvements	$ 21,000
Arkell Subdivision Upgrade	$ 21,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

4L311 Upgrade Distribution Lines Between 1st and 6th Avenue, Whitehorse	$439,000
Connect Pelly Crossing into Yukon Interconnected System	$435,000
Ketza Court Live Front Transformers Replacement	$346,000
5L628 Squanga Road Rebuild	$290,000
Right of Way Widening	$268,000
9L - Km 129 to Km 132 South Klondike Highway - Distribution Line Rebuild	$189,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2008 capital expenditures on distribution improvement projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on distribution improvement projects for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2003-2007 for distribution improvement projects were $2,217,000.

UCG-YECL-45

Reference: May 27, 2013 Application, page 9-10

YECL provides a listing of 7 projects plus 1 "Other Projects" which make up $839,000 in **2008 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Hamilton Boulevard Extension	$435,000
Whitehorse Copper Light Additions	$131,000
Foxhaven Street Lights Relocation	$ 82,000
4th Ave & Strickland Street Light Upgrade	$ 41,000
Pine Street Light Replacement	$ 25,000
Quartz Road Street Lights Relocation	$ 21,000
Carmacks High Pressure Sodium Light Upgrade	$ 20,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Hamilton Boulevard Extension	$435,000
Whitehorse Copper Light Additions	$131,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2008 capital expenditures on street and sentinel lighting projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2003-2007 for street and sentinel lighting projects were $733,000.

UCG-YECL-46

Reference: May 27, 2013 Application, page 9-11

YECL lists a $31,000 project titled "**Meters**" in 2008 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide a comparative chart by project of the 2008 capital expenditures on meters projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(d) What were the average annual capital expenditures on meters for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to WL-YECL-21(k) Attachment 1.

(d) The average annual capital expenditures over the five year period of 2003-2007 for meters were $42,000.

UCG-YECL-47

Reference: May 27, 2013 Application, page 9-11

YECL provides a listing of 5 projects plus 1 "Other Projects" which make up $509,000 in **2008 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$139,000
Oracle HRxcellence Human Resource (HR) Management	$138,000
Communication Equipment	$ 57,000
Whitehorse Service Complex Pole Relocation	$ 51,000
Miscellaneous Tools and Instruments	$ 45,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$139,000
Oracle HRxcellence Human Resource (HR) Management	$138,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2008 capital expenditures on general property and equipment projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on general property and equipment projects for the period 2003-2007?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2003-2007 for general property and equipment projects were $367,000.

UCG-YECL-48

Reference: May 27, 2013 Application, page 9-11

YECL lists a $1,035,000 project titled "CIS Billing System Conversion" in 2008 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecasts costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for this project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet.

(d) Please provide a comparative chart of the 2008 capital expenditures on the CIS Billing System Conversion project approved by the YUB in YECL's last general rates application proceeding versus actual.

(e) Please provide details of any discussions that YECL has had with YEC to establish a common billing system or to outsource the billing and customer information system in order to avoid ongoing duplication of costs within the Yukon.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to UCG-YECL-48(c) Attachment 1 for a copy of the business case. Please refer to UCG-YECL-48(c) Attachment 2 for a copy of the Excel model.

(d) Please refer to WL-YECL-21(k) Attachment 1.

(e) Yukon Electrical and YEC have had a common billing system since 2000. This has eliminated duplication in costs.

North of 60 Billing System Replacement Project

Business Case

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APPENDIX A – BUSINESS FUNCTIONALITY REQUIREMENTS

APPENDIX B – TECHNICAL FEASIBILITY REQUIREMENTS

APPENDIX C– REVENUE REQUIREMENT MODEL

1 Background Summary

The North of 60 Companies (The Yukon Electrical Company Limited, Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited), collectively known as N60, were advised in 2006 that ATCO I-Tek Business Services intended on retiring the Customer Information System (Old CIS) that had been serving the N60 companies since the 1970's.

Old CIS is a 30 plus year old vendor product based on IMS data base technology that was purchased by ATCO to provide customer care and billing functionality to all of ATCO's utility customers. This technology has not been used to develop new systems. As of 2008, ATCO's Alberta based utilities will have migrated off IMS to database systems that utilize relational database technology. This has meant that N60, as well as the non-affiliated Yukon Energy Corporation, are the only remaining utility companies using Old CIS and the IMS database technology. While Old CIS meets N60's current business needs, the loss of the Alberta based utilities has meant a loss of economies of scale and exposed N60 to the full cost of running and supporting Old CIS and the IMS database.

Due to this situation, a N60 project team was set up in 2006 to define the business functionality requirements for N60 and identify Customer Information System options. This team was sponsored by the General Manager N60 and included key N60 supervisory billing staff. ATCO I-Tek provided assistance on the technical requirements and estimating requirements as this skill set was not available within N60.

Once N60's business functionality requirements were defined, the first phase of the process was to perform a market investigation that identified vendors that provided Customer Care and Billing Services to companies with similar profiles as N60. Based on the information presented in the vendors' responses, a high level comparison and rating was performed on each vendor's product.

Two external vendors were selected for the short list. Based on confidentiality agreements, N60 is not a liberty to disclose the names of the short listed external vendors nor any of the detailed information they provided. A parent company solution, ATCO CIS, as well as the forecast cost of going it alone with the Old CIS were also included with the short list. Each of the vendors was invited to provide a four-day in depth presentation of their product's functionality. The presentations gave N60 and the vendors an opportunity to determine what type of customizations and interfaces would be needed to support N60's business and technical functionality requirements.

2 Evaluation Approach

The N60 evaluation consisted of six main activities:

- Requirements gathering
- Market investigation & evaluation of third-party solutions and ATCO CIS
- Estimation of implementation and ongoing costs for vendor solutions
- Estimation of implementation and ongoing costs of ATCO CIS.
- Estimation of ongoing costs of remaining status quo on Old CIS
- Evaluation of Potential Solutions

The evaluation was based on the following criteria and weighting (relative importance) of each criteria, with the weighted points totaling 100.

Evaluation Criterion	Weighted Point
Business Functionality	60
Technical Feasibility	5
Ongoing Support	5
Cost	30
Total	**100**

Refer to **Appendix A** for the Business Functionality Requirements document.

Refer to **Appendix B** for the Technical Feasibility Requirements document.

Refer to **Appendix C** for the forecast costs of the four options.

3 Evaluation Results

3.0.1 Business Functionality Requirements Evaluation

Based on the Business Functionality Requirements detailed in Appendix A, the project team performed an evaluation to determine if the business requirements were met by the vendor's product without modification.

The following captures the weighted score of each business functionality category.

Id#	Business Functionality Major Category	Vendor #1	Vendor #2	ATCO CIS	Old CIS	*Maximum Possible Weighted Score*
BR-1	Core Structure	4	4	20	20	*20*
BR-2	Customer Mgmt.	19	21	35	35	*35*
BR-3	Service Order Mgmt.	28	18	40	40	*40*
BR-4	Billing Accuracy Function	172	200	220	220	*220*
BR-5	Automation	12	14	40	40	*40*
BR-6	Accounts Receivable Mgmt.	16	16	20	20	*20*
BR-7	General Ledger Mgmt	12	16	20	20	*20*
BR-8	Credit and Collections	12	8	20	20	*20*
BR-9	Payment Remittance	12	16	20	20	*20*
BR-10	Meter Management	12	8	20	20	*20*
BR-11	Meter Reading Mgmt.	20	28	40	40	*40*
BR-12	Route/cycle Mgmt.	12	12	20	20	*20*
BR-13	Query and Reporting	10	8	20	20	*20*
BR-14	System Administration	48	46	80	80	*80*
BR-15	Usability	84	58.5	95	95	*95*
	Total Requirement Weighted Score	**473**	**473.5**	**710**	**710**	*710*
	Business Functionality Criterion Weighted Score Out of 60	**40.0**	**40.0**	**60**	**60**	**60**

3.0.2 Technical Feasibility Requirements Evaluation

ATCO I-Tek defined the technical requirements and the importance rating on behalf of N60 because ATCO I-Tek is the IT service provider for the ATCO Group of Companies. ATCO I-Tek also evaluated the technical requirements for each potential solution.

The following table captures the weighted score of each technical feasibility category.

Id#	Technical Feasibility Major Category	Vendor #1	Vendor #1	ATCO CIS	Old CIS	*Maximum Possible Weighted Score*
TF-1	Technical Architecture	16	12	20	8	*20*
TF-2	Configuration of Workstations	32	35	35	19	*35*
TF-3	Configuration of Application Servers	28	25	26	7	*35*
TF-4	Configuration of Database and Database Servers	24	32	35	13	*35*
TF-5	Shared Hosting Environment	0	6	10	8	*10*
TF-6	Systems Integration	8	6	16	15	*25*
TF-7	Security	18	32	40	27	*45*
TF-8	Redundancy, Backup and Recovery	25	21	35	19	*35*
TF-9	Performance and Monitoring	3	2	5	3	*5*
TF-10	Network Communication	28	26	22	30	*30*
TF-11	Configuration, installation , distribution, and licensing	18	18	30	24	*30*
TF-12	Change Management	28	24	35	15	*35*
	Total Requirement Weighted Score	**228**	**239**	**309**	**188**	***340***
	Technical Feasibility Criterion Weighted Score Out of 5	**3.4**	**3.5**	**4.5**	**2.8**	**5.0**

3.0.3 Ongoing Support Evaluation

Ongoing Support describes the level and type of support N60 will receive after the implementation of the potential solution. It includes the service level and the availability of user groups, help desks, system documentation, clearly defined response times and system maintenance. These items support the day to day operations of N60.

Ongoing support evaluation results:

Ongoing Support Requirement	Vendor #1	Vendor #2	ATCO CIS	Old CIS
User support offered during N60 business hours	12	12	16	16
Vendor production outage response time commitments	12	12	16	16
System upgrades	16	16	16	8
Documentation and usability	12	12	16	16
Access to User Groups	16	16	16	16
Maximum Weighted Score	80	80	80	80
Total Requirement Weighted Score	**68**	**68**	**80**	**72**
Business Functionality Criterion Weighted Score Out of 5 (Maximum/Total Score * 5)	**4.3**	**4.3**	**5**	**4.5**

3.0.4 Cost Evaluation

Implementation and ongoing operations and maintenance costs were forecast for each option and input into the revenue requirement model. (See Appendix C) Given the forecast costs for Vendor 1, Vendor 2 and ATCO CIS were all relatively close to each other, each of these options was given the maximum value. Old CIS was given a minimum value as the ongoing "going it alone" cost to maintain and support the system was clearly not going to be economic to N60.

Evaluation Criteria	Maximum Value	Vendor #1	Vendor #2	ATCO CIS	Old CIS
Cost	30	30	30	30	0

3.0.5 Evaluation Criteria Summary

The following outlines the total criteria weighted score for each potential solution:

Evaluation Criteria	Maximum Value	Vendor #1	Vendor #2	ATCO CIS	Old CIS
Business Functionality	60	40.0	40.0	60	60
Technical Feasibility	5	3.4	3.5	4.5	2.8
Ongoing Support	5	4.3	4.3	5	4.5
Cost	30	30	30	30	0
Total	**100**	**77.7**	**77.8**	**99.5**	**67.3**

4 Conclusions and Recommendation

Upon completion of this analysis, a number of conclusions are apparent:

- The legacy system, Old CIS, is not a cost effective solution.
- The forecast capital and ongoing operating costs, technical feasibility and ongoing support of Vendor 1, Vendor 2 and ATCO CIS are relatively consistent between each of the three options.
- Based on the Business Functionality Requirements detailed in Appendix A and the scores awarded in section 3.0.1, ATCO CIS meets the highest amount of N60's business needs in every one of the fifteen categories.

Based on investigative and analytical work completed, it is recommended that N60 proceed with the implementation of ATCO-CIS in 2008.

APPENDIX A – Business Functionality Requirements

Business Function Description	Mandatory = M Optional = 0
1. CUSTOMER MANAGEMENT	
Customer Management provides the facilities necessary for managing customer, account and service location related activities. Typically this includes setting up new services, activating the accounts for billing, consolidating accounts, issuing customer correspondence and terminating service.	M
A customer may have many customer accounts served at many locations.	M
1.1 Customer Maintenance	
Customer Maintenance provides the facilities necessary to maintain data pertaining, to the customer's profile.	M
1.1.1 Record Customer Data	
Customer data is recorded when a customer applies for service. The information typically recorded about the customer is name, mailing address, and contacts, phone numbers, identification, critical use conditions and other related customer data.	M
1.1.2 Specify Consolidated Accounts	
This process provides the means to group or consolidate one or more billing accounts to a particular customer. The reason for consolidating accounts is to create one monthly invoice for all the selected accounts as opposed to generating one invoice per account. The billing accounts underlying a consolidated account are for meters billed in **different** billing cycles. The consolidated invoice includes details for each account.	M
1.1.3 Specify Statement Accounts	
This process provides the means to group multiple billing accounts in the **same** cycle to a particular customer. The reason for grouping statement accounts is to provide a monthly statement for all the selected accounts provided that these accounts are for meters on the same billing cycle. (i.e. for one particular area or community) One invoice is generated for each individual account. One statement is produced per month.	M
1.2 Account Maintenance	
Account Maintenance provides the facilities necessary for the administration of customer accounts. Typically this includes:	
> Account set-up (before meter installation).	M
> Turn-on.	M
> Turn off.	M
> Temporary disconnect (seasonal or non-payment).	M
> Inactive account with meter.	M
> Inactive account without meter.	M

Different types of accounts include:	
> Normal account level meter.	M
> Unmetered (flat rate) - energy and demand are estimated values required for billing calculations.	M
> Outdoor lights (with or without meter) - consumption is estimated for rider calculation and sales reporting.	M
> Manually billed industrial or secondary energy accounts assigned non-standard rates.	M
> Subtract metered accounts.	M
> Company use accounts (non-billing but consumption to be recorded and reported).	M
Payment Options:	
> Pre-authorized payment plan (from bank accounts and credit cards).	M
> Average monthly payment plan.	M
1.2.1 Record Account Data	
Account data information is recorded when a customer applies for service. The information typically recorded is the customer name, any aliases, employer, phone numbers, mailing address for invoice delivery, the type of service, type of business as defined in the Standard Industrial Class Code (SIC), rate code, special use conditions and other related account data. Recording of personal data such as dob or health care number	M
For rental properties, recording owner/property management company information is required. (COIN)	M
This also provides for the recording of contract data, the account billing frequency and any billing exemptions that may apply such as late penalty charge category code, applicable provincial or federal taxes, and riders or exemptions therefrom. Franchise tax billing option required.	M
1.2.2 Assign Location	
A customer name can be associated with multiple locations.	M
The search function must allow for search by account number, last or business name or civic address. An expanded search function providing search by phone number, mailing address, date of birth. Legal or rural address, or “sounds like” name is desirable.	M
1.2.3 Turn-On Account	
The turn-on function is used to activate the account for billing purposes. A connect fee and security deposit may be optionally assessed and the appropriate rate schedule is assigned.	M
This function **MUST** create service field orders. Field order production must be automatically assigned by location and or company.	M
1.2.4 Administer Outdoor Lights	

The outdoor light function is used to set-up and administer outdoor lights. A customer can be billed different monthly rates for outdoor lights depending on the type and size of the lamps. Outdoor lights are normally connected before the meter and consumption is not recorded as part of the monthly meter reading. However, an average monthly kilowatt-hour value is assigned to each light rate code and must be reported as consumption for monthly statistics. For example, a 100 watt HPS sentinel light has a base charge of $11.64, a 14.63% rider charge of $2.18 and GST of $.97. For regulatory purposes, the system must also record consumption of 40 kWh even though this was not a “measured” amount.	M
A customer should receive one bill for both metered energy as well as any light charges.	M
There must also be a function to bill lights on an account without a meter. This type of account will typically have to calculate a bill combining several different types of light rate codes.	M
1.2.5 Administer Equalized Payment Plan (Budget) Accounts	
This function allows for the set-up, monitoring, and removal of accounts on the equalized payment plan. The billing system would calculate potential budget amount based on previous year’s consumption.	M
Ideally, the settlement date for budget accounts does not have to be the same for all accounts.	O
Monitoring refers to the process of assessing whether the monthly budget amount is set too high or too low. Ideally, the customer makes 12 equal payments during the year. System must be able to report budget customers monthly. A mass change mechanism to increase/decrease budget amount is desirable.	M
1.2.6 Temporary Off Accounts	
The temporary off function is used to temporarily deactivate an account. The temporary offs are issued for delinquent accounts, vacation, safety, special usage or seasonal peak load customers.	M
In the case of a delinquent temporary off, a final invoice may be required after a predetermined number of days.	M
This function **MUST** create service field orders.	M
1.2.7 Final/Transfer Accounts	
The final function is used to finalize an account. A final invoice is prepared to bill the customer's account to a specified date and reading.	M
When finalizing an account, any deposit amount held will automatically be applied to the final invoice amount if the customer is not establishing a new account. If the customer's final accounts receivable results in a credit balance, a refund cheque will automatically be initiated by the system.	M
The transfer function is used when the customer is transferring from one service location to another. The final invoice accounts receivable is transferred to the customer's "moving to” account. In addition, current customer data must transfer. (I.e. credit data, deposit data, budget data, and customer data.)	M

This function **MUST** create service field orders.	M
1.3 Location Maintenance	
Location Maintenance provides the facilities necessary to record data for service locations. Typically this includes setting up a new service location, installing a meter or outdoor lights and recording related activity.	M
A new service location number is automatically assigned to create a location record if no service has previously existed at a service location.	M
A location can be associated with both an incoming and an outgoing customer account, but must assign a unique identifier to each customer.	M
1.3.1 Record Location Data	
This function is used to establish a new service location and maintain existing locations. The information typically recorded about location includes:	M
Service address, annual consumption, transformer size, meter number and location, meter reading cycle, route and sequence, community identifier, customer contribution (if applicable), source of power and load information.	M
All metering devices in commission at the premise (i.e. current transformers or potential transformers) are recorded for billing multiplier calculation.	M
1.3.2 Install Meter	
The meter install function is used to record meter information pertaining to the meter installed at the service location. A control function must ensure a meter can only be assigned to one location at any given point in time and ensure the meter used is "in stock"/inventory for the specified company.	M
This function **MUST** create service field orders	M
1.3.3 Change Meter	
The meter change function is used to record the exchange of a meter at the service location. The removed meter will be returned to meter stock or retired.	M
The meter change will record the new meter information and calculate consumption for the removed meter as well as the new meter, for the subsequent billing. If consumption falls outside the edit and validation parameters pre-set in the system, a warning must be generated. The change function must be available for inactive accounts.	M
The meter change could be the result of a faulty meter, routine meter change program, damaged meter or load change.	M
This function **MUST** create service field orders.	M
1.3.4 Remove Meter	

The remove meter function is used to record the fact that a meter has been removed from a location and returned to meter stock. The billing system will create an account record to maintain the service information on the account.	M
The remove meter function can be used separately or in conjunction with a meter change.	M
This function **MUST** create service field orders.	
	M
1.3.5 Install/Remove Outdoor Lights	
The install/remove outdoor lights function is used to record information pertaining to the outdoor light installation and removal at the service location. Outdoor lights may or may not be metered.	M
This function **MUST** create service field orders.	M
1.4 Customer Communication	
Customer Communication provides the facilities necessary for administrating customer correspondence. Typically this includes monthly system generated bill messages related to aged accounts receivable, budget and pre-authorized payment customers. This function must also offer a minimum of two adhoc bill messages that can target specific customer groups (i.e. by community or rate class).	M
A function must exist to support/facilitate customer surveys. Requirements include the ability to select customers on the basis of various criteria such as community, rate class or consumption levels.	O
2. SERVICE ORDER MANAGEMENT	
Service Order Management supports all service orders initiated by customers, employees and the system. The term " Field Service Orders" includes customer contacts, requests for field services, investigations, requests for follow-up actions, etc.	M
Field service orders are categorized to support statistical information and the measurement of customer service response times. This facility **must** automatically print field service orders, once initiated, for action. A pending service order report will be automatically produced for the designated responsible party(ies) for periodic follow-up.	M
Field service orders are not work orders. Work orders are used for capital additions, as well as repair and maintenance. This activity has implications on the capital assets and depreciation. Field service orders have no such implications.	
2.1 Template Maintenance	
A template defines the types of service orders, their generic priorities, escalation procedures, the designated responsible persons or departments, the print location, etc.	M
The template also defines the conditions under which the system will initiate the prompt for follow-up action orders.	
2.2 Service Order Maintenance	
Service Order Maintenance provides the facilities necessary to initiate, query, change, print, cancel, complete, close and reactivate service orders. It also sets the priority and automatically routes the order to the responsible party(ies) based on manually input directives or defaults to the template assignment.	M

The system reviews the status of the orders on a regular basis and the escalation procedures defined in the template are implemented when necessary.	M
Query can be by company, by service area, by location, by account, by category, by status, etc., provided there is sufficient security authorization.	M
When a service order is changed, cancelled or reactivated, an audit trail is required of the changes made, the reasons for change, cancellation/re-activation and the person who initiated the action is maintained.	M
Service orders **MUST** be printed locally at a designated printer.	M
2.3 Produce Statistics	
Daily, monthly and yearly statistics such as volume of service orders by category, service orders completed, outstanding, cancelled, etc., will be produced for the head office, districts, agencies, departments or responsibilities.	M
2.4 Balance and Control	
The system will ensure that service orders initiated, completed orders, outstanding orders and the cancelled orders can be reviewed and monitored on a timely basis.	M
Facilities are provided for supervisors and/or authorized employees to administer service orders. Typically, the facilities will be used for general leveling of workload, monitoring of service order completions and service orders pending.	M
3. BILLING	
Billing is the processing required to calculate and adjust bills for each service and to produce individual or consolidated invoices for each customer. Billing can be triggered by cycle, by date or by event, depending on the profile of the service account.	M
An operator manual and/or process and procedures manual must be supplied for account billing, error message and correction, data field identification, credit and collections, and cash system procedures.	M
3.1 Maintain Rates	
Rates are designed to bill various types of accounts. Each rate may contain a number of charge components. Current components include:	M
1.) Basic customer charge or demand charge	
2.) Unit charge based on consumption - may be stepped	
3.) Riders as a percentage of a base rate or based on consumption	
4.) Income tax rebate	
5.) GST (invoice must provide subtotal before GST)	
6.) Territorial Sales Tax or Municipal Franchise Tax	
7.) Territorial Rate Relief or Territorial Support (percentage of customer and or unit charge. May include a claw back mechanism if consumption exceeds defined parameters).	
8.) Optional green rates must be supported as designed to allow for elective customer choices to support energy conservation initiatives.	

9.) Time of use rates must be supported as designed to allow for elective customer initiatives.	
New rates are added as required by business requirements. Existing rates are modified upon regulatory approval.	M
Rates and or riders no longer in effect should be retained by the system to allow proper automatic calculation for customers who require billing adjustments that straddle change dates.	M
Strong date-effectiveness features are required for rates.	M
3.2 Manage Rate Tests	
This function provides the ability to test the impact of approved rates on the customer accounts. Users can specify the version of rates, riders, taxes etc. to be used in the rate test. Users can also choose to enter generic billing data or select actual production account data for testing. Rates and Pricing will continue to use existing rate design software to design and develop rates. Data file will be provided for this software from the billing system.	M
The objectives include:	
> Understanding revenue impact.	
> Ensuring that rate relief values are correctly set and ensure billing accuracy.	
Users control the elevation of tested rates into the production environment. Proper backup and recovery facilities are provided to support the elevation. Historical rates must be retained for cancel rebill functionality.	M
3.3 Bill Customers	
3.3.1 Bill Utility Service	
3.3.1.1 Calculate/Estimate and Validate Consumption	
Consumption is used for tracking energy usage and for billing. Units of usage (Energy kWh's and demand kW's) are measured by meter reading, then converted into energy consumption by applying a billing multiplier.	M
For non-metered services, such as outdoor lights, consumption is estimated based on the number of lights and the voltage of the light bulb. All applicable billing components such as riders are calculated on this estimated consumption as required. This estimated consumption value is reported for sales purposes.	M
For non-metered services, such as TV amplifiers, consumption and demand are estimated based on the number of units. The applicable general service rate is applied to the estimated value. This consumption value is also reported for revenue purposes.	
Meters can measure energy or peak demand usage during the billing period. Normally, consumption is calculated for each register on the meter over the billing period. One of the exceptions is the time-of-use meters. Multiple sets of readings are recorded daily based on the time interval agreement. Consumption is calculated for each interval by day. Consumption for the corresponding intervals are accumulated and maintained separately.	M

The billing multiplier for each meter is made up of a number of components. If one of the components changes during the billing period, more than one billing multiplier will be calculated.	M
The actual units of usage are calculated from valid meter readings recorded for the billing period. If there is a billing multiplier change during the billing period, readings will be taken at the time of change. The billing multipliers will be applied to the corresponding portions of the usage.	M
In the absence of valid meter readings, the consumption is estimated based on a formula involving the days of usage, estimate factors, annual consumption, etc. A variable estimate code must be available to identify accounts that cannot be estimated.	M
Consumption is validated using established reasonable high/low ranges. The ranges are determined based on the estimated consumption of the meter for the billing period. A daily report must be produced for follow up on consumption outside established parameters.	M
3.3.1.2 Calculate Charges	
The billing rate determines which pricing factors to use for various charges. If the billing rate changes during a billing period, the consumption is prorated based on the number of days used before and after the rate change. The previous and current pricing factors are applied to the appropriate prorated portions of the consumption. The same principle applies if the service account is assigned a different rate (code) during a billing period.	M
Flat rate billing for outdoor lights is based on a fixed charge per mantle. Different sizes of lights are billed at different rates. Appropriate other charges for rate components may be calculated on this fixed charge (e.g. Rider calculated on a base charge).	M
Other billings are based on usage and metering arrangements. An account may be billed on a combination of energy and demand usage. Calculations vary according to the design of the rates. In the case of time-of use meters, different rates can be applied to the same meter based on different time measurement intervals.	M
The billing demand may be estimated or measured and will have a minimum approved charge value. An example of this type of calculation is the following approved rate for Yukon Electrical. The other N60 utilities may have different calculation types and values.	M
(a) The highest metered demand during the billing period.	
(b) The highest metered demand during the 12 months ending with the current billing month, excluding the months April through September.	
(c) The estimated demand.	
(d) 5 kW.	
Some customers have contract agreements for selected service accounts. The contract terms which affect billing are applied to the billing process. This may impact both demand and energy charges.	M
3.3.1.3 Record Manual Bill	
When a bill for a service is manually calculated, the normal billing process is suppressed or replaced. A staff member must be able to manually enter the charge components as calculated.	M

3.4 Bill Corrections	
A customer's current and prior bills may need to be corrected for reasons such as over-estimating consumption or bills calculated using an incorrect rate assignment.	M
Corrections can be performed by:	
1. Manually applying net revenue adjustments when an automatic function is not available.	M
2. Automatic system adjustment applies when previous month's bill factors were incorrect. The billing period may span multiple months.	M
3. Manual re-bill initiated by customer service staff. Calculation is system generated. (i.e. no bill was produced in the first place)	M
An automatic or manual re-bill initiates the normal billing process.	M
3.4.1 Cancel Billing	
In order to re-bill, the erroneous bills must be cancelled first. The system will also initiate cancellations when billing accounts recording actual meter readings compares the previous bill and finds estimated bill too high. The entire previous month's bill is cancelled and a new bill calculated. This process must be provided for multiple billing periods as accounts may be estimated for several months. Charge components must be credited to appropriate GL accounts.	M
3.4.2 Adjust Revenue/Consumption	
Revenue adjustments apply to valid bills. The revenue adjustment is used to net adjust any of the charge components in current or prior bills.	M
3.5 Produce Invoice	
North of Sixty invoice customers for the services provided. Invoices are sent to the bill payer identified at account set up time.	M
North of Sixty places high value on an invoice which:	
> Communicates clearly to customers and is accurate.	M
> Is aesthetically pleasing.	M
> Identifies each component of bill calculation by line item with descriptor for each charge e.g. Energy charge, demand charge, riders, taxes, etc. (GST must be shown as a separate value after a subtotal of charges before GST)	M
Note: A 13-month consumption history histogram would be a desirable feature.	O
Given that North of Sixty are largely distribution companies purchasing wholesale power from a generator, it would also be desirable to break out the genco vs. the disco components of the bill.	O
3.5.1 Produce Regular Invoice	
Regular invoices are produced when the service accounts are billed. Every service account is associated with a meter reading route. The route is read on a particular day of the month. This day is associated with a billing cycle number. The billing cycle number determines the billing cut-off day of the month.	M

The account balance forward less the payments made since the last invoice, current period charge components, adjustments, service charges and deposits are all listed and totaled as the invoice amount.	M
Budget accounts are invoiced a predetermined fixed amount rather than the current period charges as calculated. **(Note: Due to recent GST audit results, consideration should be given to calculating GST based on the predetermined fixed amount rather than the bill calculated on consumption.)** The cumulative amount due to / from a budget customer is disclosed on each month's invoice.	M
The payment due date and potential late payment penalty accessed is also printed on the invoice. The calculation method and value varies among the 3 N60 companies.	M
3.5.2 Produce Consolidated Invoices	
Some customers have multiple service accounts and prefer to receive one consolidated invoice for all or some of their service accounts. The services accounts are billed in different billing cycles and the regular invoices can be suppressed.	M
The consolidated invoice is produced on a pre-determined cycle agreed upon between the customer and North of Sixty. Any adjustments after the billing date and prior to the invoice date are included in the invoice.	M
3.5.3 Produce Invoice on Alternate Media	
Customers are provided with detailed billing information on all service accounts on the media requested (i.e. hardcopy or disc). The report can also provide subtotals by cost centre/department as defined by the customer.	M
3.5.4 Produce Usage Statement	
Customers are provided with system generated summary billing information for each of the previous 12 months. This is typically used by:	M
> customers operating in-home businesses as part of their year-end accounting and tax processes.	
> Realtors for the package of information for prospective buyers.	
3.5.5 Maintain Global Messages	
Facilities are provided to enter message text, set priority, and define effective and expiry dates and the selection criteria for the designation of messages. May be different for all companies.	M
Messages must be approved by a pre-defined responsibility such as Corporate Communications prior to being printed. Once approved, no further changes are allowed until the approval is revoked.	M
3.5.6 Maintain Account Messages	
Facilities to enter account-specific message, which will print on the next invoice and then, are deleted.	O
3.6 Maintain Accounts Receivable	
Each charge component billed will credit or debit the service account accounts receivable. Any cancel, cancel/rebill or manual adjustment will also adjust accounts receivable accordingly. For customers with multiple service accounts, a consolidated accounts receivable must also be maintained.	M

3.7 Electronic Posting to General Ledger	
All revenue, adjustments, tax obligations, service charges, deposits, etc. are accumulated and posted electronically to the appropriate general ledger accounts.	M
A table, which is used to assign the appropriate general ledger account numbers to corresponding items, is maintained. If a general ledger account number is changed, the table must be modified accordingly.	M
The electronic posting should provide sufficient detail for audit as well as resolution of reconciliation problems between the general ledger and the billing system.	M
3.8 Manual Posting to General Ledger	
Sufficient system generated hard copy detail should be available to prepare daily, weekly and/or monthly journal entries not provided by the electronic posting process. It is desirable that manual journal entries are limited and the electronic journal cover all possible requirements. However, manual posting functionality must be available for exceptions.	M
4. ACCOUNTS RECEIVABLE MANAGEMENT	
Accounts Receivable Management provides the facilities necessary for managing the customer's accounts receivable. It is an important control item at the individual account level as well as at the North of Sixty Companies level. An interface is required to update the appropriate accounts in the GL.	M
The accounts receivable function manages the sum of all due amounts for the balance of an account. The total accounts receivable of all accounts reflects the amount owed to each of the North of Sixty Companies. This data is always managed with controls and audit trails.	M
4.1 Transfer Accounts Receivable	
The accounts receivable transfer function is used to transfer an accounts receivable amount "to" or "from" a customer's account. With each type of transfer there are two options available (i.e.: transfer partial or total charges or credits).	M
Tracer data is created at the transfer "from" and transfer "to" accounts for cross-reference and audit trail purposes.	M
Some reasons for accounts receivable transfers are:	
1. Customer requested transfer from one account to another.	
2. Customer moving from one location to another.	
3. Charges or credits removed from a customer's account.	
4. Charges or credits transferred to a customer's account.	
5. Payment corrections.	
6. Account balance transferred to write-offs.	
4.2 Adjust Miscellaneous Accounts Receivable	
The miscellaneous accounts receivable function is used to post miscellaneous charges or credits such as connect charges, write-off adjustments, returned cheque charges, penalty charges and special rate refunds to a customer's account.	M

4.3 Refund Accounts Receivable	
The refund accounts receivable function is used to generate a refund when a customer's account has a credit balance as a result of an overpayment, an application of the deposit or a special rate refund. The credit balance of the account is reduced by any existing accounts receivable.	M
The refund may be initiated either at the customer's request or by a North of Sixty Company in the case of a finalized account.	M
This function also provides for the managing of variable interest rates applied to refunds.	M
Refund cheques are produced automatically for all final accounts with credit balances and sent for manual review by staff.	M
4.4 Post Payments	
Post Payments provides the facility necessary to post payments to a customer's account.	M
Payments are automatically posted to specific accounts receivable items such as deposit, service fee, 30, 60, & 90-day arrears, current charge, fees and budget arrears in a predetermined order. This function must provide for manual override. Payments received for consolidated accounts will be allocated automatically to each individual account.	M
The accounts receivable for the customer's account is reduced by the applicable payment amount. If the payment amount is in excess of the balance due, the result will be a credit balance in the customer's accounts receivable. This credit balance may be used to reduce the accounts receivable balance on another account.	M
The post payment facility will prevent the posting of duplicate batch payments.	M
Unpostable batch payments are identified for further investigation and clearance. A suspense account must be available for default posting.	M
4.5 Process Returned Cheque	
Returned Cheque/pre-authorised payment processing provides the facility necessary to record and maintain returned item data. Typically this includes recording the returned item amount, date, reason and optional service charge. The account receivable must be updated accordingly.	M
When a payment is returned by a financial institution, the account receivable of a customer's account is adjusted to reflect the amount of the bank returned cheque. A service fee may be assessed to the customer's account depending on the reason for return.	M
4.6 Accounts Receivable Ageing	
Accounts Receivable Ageing provides the facility necessary to age and maintain accounts receivable items such as 30, 60, & 90-day arrears and fees for all accounts. An analysis of each customer's account receivable at cycle billing determines the ageing process.	M
4.7 Calculate Late Payment Penalties	

This facility provides the means to assess, charge, or waive late payment penalties. Penalty is calculated based on the penalty charge base (aged receivable balance) less all payments posted as of statement date. If the outstanding balance of an account is not cleared until after the payment due date, a penalty charge may be applied. Late payment charges are waived due to automatic adjustments or manual adjustments. The account receivable for the customer's account is increased by the penalty amount charged. Penalties must be reported to a separate GL revenue account and may differ in both calculation and rate between the N60 companies.	M
4.8 Maintain Payment and Credit History	
A customer's payment history must be retained on the system for a pre-determined period of time even if status of the account changes from active to closed:	M
> Support process of determining the security deposit amount due for a new account application.	
> Reduce bad debt write offs by limiting credit to customers with a poor payment record.	
4.9 Electronic Posting To General Ledger	
This function provides the facility necessary to post accounts receivable items such as payments, refunds, returned cheques and write-offs to the general ledger.	M
A table, which is used to assign the appropriate general ledger account number, is maintained. If a general ledger account number is changed, the table must be modified accordingly.	M
4.10 Manual Posting To General Ledger	
Sufficient system generated hard copy reports must be available to prepare daily, weekly and/or monthly journal entries covering the above noted transactions.	M
5. GENERAL LEDGER MANAGEMENT	
General Ledger Management provides the facilities necessary for managing North of Sixty Companies financial transactions. All companies maintain a separate General Ledger.	
The general ledger function manages all journal entries received from other systems. This function produces analytical and financial reports. This data is always managed with controls and audit trails.	
5.1 Manage Chart of Accounts	
The chart of accounts function is used to establish and de-activate chart of account codes.	M
5.2 Manage Cost Centers	
The cost centres function is used to establish and de-activate cost centre codes.	M
5.3 Proof Journal Entries	
The proof journal entries function is used to validate journal entries and to generate error reports about the journal entries received from sub-systems.	M
The errors are typically addressed by the financial accounting staff in consultation with the staff responsible for the originating system.	

5.4 Post Journal Entries	
The post journal entries function is used to update valid journal entries received from sub-systems.	M
5.5 Produce Financial Statements	
The produce financial statements function is used to produce the following reports:	M
1. Income statement.	
2. Balance sheet.	
3. Sources and uses of funds statement.	
These reports can be produced in various styles:	
1. Comparative year to year or year to budget.	
2. At various levels of detail and/or consolidation.	
These reports are used:	
1. For financial performance management.	
2. As input to the corporate financial consolidation processes.	
5.6 Produce Analytical Reports	
The produce analytical reports function is used to produce the reports that support the following processes:	M
1. Account analysis.	
2. Balance and control of the general ledger.	
The styles of reports can include:	
1. Tabular.	
2. Chart.	
6. CREDIT AND COLLECTIONS MANAGEMENT	
Credit and Collections Management provides the facilities necessary for managing activities related to deposits, credit tracking and collection actions for delinquent customer accounts. This facility will enable North of Sixty Companies to equitably carry out established policies with minimal manual intervention. Must provide a facility for recording customer payment arrangements. Must also provide a mechanism to exclude/suspend customer accounts from collection activities based on customer type or needs. Requirements may vary between companies and communities.	M
6.1 Deposit Maintenance	
Deposit Maintenance provides the facilities necessary for managing, refunding and transferring of customer's security deposits.	M
6.1.1 Manage Deposits	
This function will provide the facilities necessary for recording and maintaining all pertinent information about deposits and the depositor.	M

A deposit may be required when a customer applies for service or as a result of credit review at collection order time. The deposit will be held in trust by North of Sixty Companies until the customer establishes a satisfactory credit rating.	M
The system will automatically calculate a suggested deposit amount based on three (3) times the account's estimated average monthly bill amount. A human decision is required to determine the deposit requested based on the customer's credit history. This amount may differ from the suggested amount. The requested deposit is applied to the customer's account and is billed to the customer.	M
The system will prompt for action if a deposit requires review for refund or increase based on credit and payment history.	M
6.1.2 Calculate Interest	
This function allows for the automatic calculation of accrued interest on security deposits by the system. The system will apply interest earned on the deposit to the account receivable amount as directed.	M
The interest rates to be applied to deposit refunds will vary on a regular basis. The system must have a facility to modify the interest rate.	M
6.1.3 Refund Deposits	
This function allows for the refunding of security deposits and interest earned to date.	M
Deposit is refunded to a customer with interest when:	
1. The customer's account is finalized.	M
2. A satisfactory credit rating has been established based on payment habits.	M
3. At the customer's request with staff approval.	M
Deposit can be refunded in three ways:	
1. Applied as a credit to the customer's account receivable.	M
2. A system generated refund cheque upon anniversary date based on specified credit/payment history	M
3. A system generated refund cheque if a credit balance remains after account is finalized.	M
6.1.4 Transfer Deposits	
Deposits can be transferred from one account to another in whole or part. Deposit transfers can also occur as result of the customer moving from one location to another.	M
6.2 Credit Maintenance	
Credit Maintenance provides the facilities necessary, for the customer applying for service, to establish credit, or for an existing customer to re-establish credit. This facility will support credit tracking, recording of guarantees and the maintenance of energy assistance programs.	M
6.2.1 Credit Tracking	
This process provides the means to analyze a customer's accounts receivable and credit status. This will determine the eligibility of the credit rating update and actions to be taken in case of delinquency.	M

The credit rating upgrading or downgrading formula is based on past payment habits and collection activities.	M
6.2.2 Record Guarantee	
This function allows for the maintenance of all pertinent information regarding the guarantee amount and the guarantor.	O
The guarantee amount may be used to reconcile the customer's account in the case where there is default of payments.	O
6.3 Collection Maintenance	
Collection Maintenance provides the facilities necessary to review delinquent accounts and perform the necessary follow up. This facility allows for the automatic and/or manual production of final disconnect notices, production of collection orders, managing credit extensions and managing write-offs. Adequate system space must be available to record historical information on actions performed both manually and system generated. The system must allow for manual control of a customer's case. Printing options must be available for different types of collection orders/letters.	M
6.3.1 Produce Final Disconnect Notices	
In a predetermined time period after a delinquent customer's last invoice, an analysis is performed to verify if a payment was received. If still delinquent, a Final Disconnect Notice will be produced advising the customer that service will be discontinued if the account is not paid. This function allows for the creation of different case types based on credit and payment history as well as customer class. Customized notices can be created based on case type. Collection actions may be suppressed manually or by certain conditions on the account, such as a payment arrangement. This function must allow for customized parameters to be set for each service area.	M
6.3.2 Produce Collection Orders	
If a customer has not cleared the delinquent balance within the specified number of days after issuing the final disconnect notice a collection order is prepared automatically based on preset parameters. The collection order is printed for the necessary field action follow-up. Different types of collection orders are necessary depending on community location and weather conditions.	M
6.3.3 Record Payment Arrangements	
This function allows North of Sixty to arrange a credit extension agreement with a delinquent customer. Agreements will be made according to length of time to pay, amounts to be paid, eligible charges, etc. This function allows adequate system space to record data regarding payment arrangements and automatically produces a review if arrangements are not kept. The system will suspend all collection actions during this time.	M
6.3.4 Manage Write-offs	
This process provides the facilities necessary to administer written-off accounts.	M
All accounts with an unpaid balance for a period longer than a specified number of days after final invoice preparation are automatically written-off against the allowance-for-bad-debts account. Must provide facility to force account to write off as required.	M
The written-off account is transferred into the uncollectible or unclaimed monies file after a specified period of time. Historical record retained for audit purposes.	M

Any finalized account with a zero balance or any account written-off will be retained for historical reference. Purging of records will be managed as required.	M
The original account number is retained as tracer data. Subsequent payments are accepted for written-off accounts and are reported separately for accounting purposes.	M
Unpaid final invoices, after a specified number of days, maybe turned over to a collection agency for possible collections. This process will normally be system controlled, but must allow for manual control.	
6.4 Electronic Posting to General Ledger	
This process provides the means to automatically post deposit and write-off amounts to general ledger account.	M
A table, which is used to assign the appropriate general ledger account number, is maintained. If a general ledger account number is changed, the table must be modified accordingly	M
6.4.1 Manual Posting to General Ledger	
This process must provide sufficient system generated hard copy detail to prepare the necessary journal entries to post payments and write off amounts to general ledger.	M
7. PAYMENT REMITTANCES MANAGEMENT	
Payment Remittances Management provides the facilities to record payments, credits/debits and returned cheques for the purpose of updating customer and company accounts.	M
7.1 Process Remittances	
Payment Remittances provides the facilities to process payment activities through the following sub-systems. These sub-systems allow for the processing of payments, credits/debits and returned cheques.	M
Remittance Processors: Hardware and software to process large volumes of payments and adjustments received through the mail and from Financial Institutions.	O
Online Cash Registers: Hardware and software to process medium volumes of payments and adjustments received at authorized payment locations.	M
Data Entry Terminal: Terminals and software to process small volumes of payments and adjustments received at authorized locations.	M
Using these devices means customer account validation is performed either on-line or during the batch update process.	M
Types of remittances will include:	M
1. Cash.	
2. Cheques.	
3. Pre-authorized bank payments – EFT (system must create file to interface with banking system software).	
4. Debit card.	

5. Credit card.	
Other types of remittances may also include:	O
1. Pre-authorized bank payments from credit card.	
2. E-Billing (both “biller-direct” or third party bill consolidators.)	
7.1.1 Process Payments	
This function allows for the processing of the following payments:	M
1. Regular utility payments that will credit the customer's account receivable.	
2. Non-utility payment to the financial system general ledger (i.e. transformer rentals, purchase of power poles, etc.).	
3. non-utility charge to the financial system general ledger (i.e. bank charges, cash shortages)	
4. Non- utility payment for non-electric sales accounts (i.e. cookbooks, hats, etc.).	
All details pertaining to the payment, such as source number, receipt number, type of payment, location of where the payment was made, etc., will be recorded.	M
Payments can be directed to specific accounts receivable items such as deposit, service fee, 30, 60, 90-day arrears, current charge, budget arrears, etc.	M
7.1.2 Process Credit/Debit Adjustments	
This function allows for the processing of a manual entry to adjust a payment amount or to reverse an incorrect entry.	M
7.1.3 Process Returned Cheques	
This function provides the facilities necessary to process returned items that are returned from a financial institution and must be charged back to the customer's account. A service charge must be optional based on reason for returned item.	M
7.2 Communicate With Remittance Sub-Systems	
This function will provide the facilities necessary to interface with external systems for processing payments. This will include pre-authorized payments and payments made at banks. It may also include credit/debit card payments and electronic funds transfers.	M
7.3 Balance And Control Remittances	
Balance and Control Remittances provide the facilities necessary to reconcile remittances processed in the billing system to funds recorded in the general ledger bank account.	M
Each collecting office currently balances daily payment (Daily Cash Report – DCR) totals to their bank deposit. These totals are then summarized and reconciled to the general ledger and the monthly bank statement.	M
Various balancing and control reports are produced in a timely manner to support this function.	M
8. METER MANAGEMENT	

The Meter Management function manages all in-stock and in-service meters. In-stock meters are inventory at the Meter Shop or held at various Service Points while in-service meters are installed at the customer locations, at company facilities, etc. The meter sample testing and seal extension programs are currently managed by ATCO Electric and it is anticipated that this service will continue to be provided by AE.	
8.1 Purchase Meters	
The meter purchase function is used for adding new meters to the meter inventory. A standard type size format indicates meter characteristics. A number is added to the type size indicator to create a unique identifier for each meter. All inventoried meters must be recorded in ATCO-CIS to support the functions performed by ATCO Electric.	M
Meters can be purchased individually or in large quantities.	M
8.2 Maintain Meter/Device Details	
This function will maintain the characteristics for the various meter and device types and must accommodate automatic meter reading devices.	M
The information recorded for meters includes the meter number, assigned company number, manufacturer's serial number, purchase date, cost and other characteristics associated for that type of meter. Company equipment installed at the premise (CT's & PT's) must be recorded in the system.	M
Bar Coding could be used to facilitate the recording of meter and device details directly from the manufacturer.	O
8.3 Track Meters/Devices In Service and In Stock	
This function will track the movement of meters in-service and in stock/inventory. It will also record all pertinent information on the meters such as purchase price and date, internal multiplier, demand high scale, number of dials, current/potential transformer requirements, next expected test year, etc.	M
Meter purchases will initially put all meters into stock while meter removes and changes will move meters from in-service to stock/inventory.	M
Meter installs and changes will record the movement of meters from meter stock/inventory to an in-service account. The facility will be in place to track all meters that are installed at a particular location. This function must allow only one active unique location per meter to prevent duplicate premises assigned to one meter.	M
This function will also track the movement of a meter from the date purchased to the date retired. It will also provide for recording a meter back into stock on an immediate basis.	M
8.4 Maintain Meter/Device Relationships	
This function will provide the facility to record devices that are attached to specific meters. This information will be useful for reporting the location of recording devices used by Load Research, etc.	M
8.5 Sample Meters	
Meter sampling is a process required under the Electricity Inspection Regulations Act (Measurements Canada) to randomly select meters for the purpose of verifying the accuracy of those meters.	M

The facility will be in place to generate recall orders for selected meters from the sample group.	M
8.6 Test Meters	
The meter test function is used to record test results.	M
Meter tests, as a result of new purchases, periodic testing or customer requests are posted to the in-service meter or in-stock meter.	M
History will be retained on all test results (i.e. dates, proof readings, and follow-up actions).	M
8.7 Retire Meters	
The meter retirement function is used for retiring meters from the in-stock meter inventory. As these meters are no longer serviceable & tracking is no longer required.	M
All meters that are to be retired must be removed from active service and returned to stock prior to retirement.	M
8.8 Balance And Controls	
All meter purchase transactions, meter tests, and meters retired, will be controlled by the meter department and held in an equipment group in ATCO-CIS	M
In the case of meters purchased, the purchased date and purchase order number will be retained as part of the purchase transaction.	M
When purchasing mass quantities of meters, a batch header is used to verify the number and total cost of meters within each batch.	M
Meter inventory is reconciled by manually counting the meters in stock and verifying to the number of meters recorded within the system.	M
Meter seal information will be recorded as required to track possible energy diversion.	M
9. METER READING MANAGEMENT	
Meter Reading provides the facilities necessary to accurately and systematically track consumption at each service after a meter is installed. The ITRON Premier Plus 4 Genesis Portable Computer (G5) is in use in the field. Computer Aided Dispatch (CAD) currently used as interface between PP4 server and billing system. CAD will be retired at end of 2007. Replacement system being developed to be in-service by 2008.	
9.1 Route Maintenance	
Route Maintenance is used to maintain the route and read sequence assignments and to ensure that the number of meters assigned to each route is reasonable.	M

Routes may be split or combined. Re-routing is the change of the assigned meter reading route number. Each meter in the route must be assigned a unique route sequence number. Re-sequencing is required when changes are required in the assignment or as a result of re-routing. Functionality for mass changes must be available.	M
9.2 Schedule Meter Reading	
Meter reading schedules must be produced for meters to be read on-cycle. Readings must be co-coordinated with billing cycles. Off-cycle readings (event driven, i.e. special reads, finals, turn-ons, etc.) must be allowed for billing purposes. This function must allow for the excluding of specified routes and/or individual accounts. This function must allow for different reading schedules by company to accommodate unique holidays etc.	M
9.3 Record Meter Reading	
The meter reading function records consumption readings and other meter reading data for each service. Meter readings may be entered at any time during the month and a facility must exist to record the interim readings for historical reference.	M
Meter reading will be used to complete turn-on/turn-off orders (i.e. readings that have same date as the service request).	M
High/low consumption validation for consumption and demand is performed when the reading is captured by the GPC and at bill calculation time. A report of exceptions must be produced for follow up action.	M
9.4 Communicate with Meter Reading Sub-Systems	
This function provides for the interface to external meter reading sub-systems (i.e. ITRON, AMR, etc.).	M
9.5 Produce Performance-Statistics	
Route statistics are produced to assist in managing route assignments and route sites. This includes the number of meters to be read, by type of account in each route, the number and percentage of actual reads, number of skips and the actual read time of each route.	M
Statistics are also produced to monitor various performance standards associated with reading meters data. (I.e. number of meters read, time required to read a route, etc.).	M
9.6 Balance And Controls	
The meter reading route header precedes each batch of meter readings to verify the number of meter readings within that batch. Meters that are not actually read must be identified for follow-up action.	M
The number of transactions transmitted through meter reading devices must balance to the number of transactions received by the mainframe in an upload/download situation.	M
10. ORGANIZATION SUPPORT	
Organization Support provides the facilities necessary to support activities related to identifying customer growth and energy conservation.	

Departments, within North of Sixty, that use customer-billing data for additional activities, perform these functions. This data typically includes number of customers by rate class, sales by service area and rate class, average consumption by customer, etc. Pricing and Engineering have been identified as the major areas using this data. This will assist them in performing their business functions.	
10.1 Pricing Support	
Pricing Support provides the facilities necessary to support rate development, pricing analysis, conservation services and product support.	O
10.1.1 Rate Development	
This function will provide the facilities necessary to perform rate comparisons for individual customers or various rate classes. System must have ability to provide a data file to interface with software used by rate design group.	M
This will enhance the capabilities to supply the customer or a group of customers with the best applicable rate.	M
10.1.2 Marketing Analysis	
This function will provide the facilities necessary for recording and maintaining customer profiles. This will serve to identify potential new customers and retain customer information if the customer becomes active.	O
10.1.3 Conservation Services	
This function provides the facilities necessary to support demand side management. This includes promoting energy efficient products, and the analysis of the facilities owned by customers at their own locations.	O
10.2 Engineering Support	
The Engineering Support function will provide for the recording and maintenance of company owned facilities and their locations. It will also provide their distribution relationship for load research and distribution planning.	O
10.3 Geographic Coding	
This function will provide the capability to identify all company facilities and their grid relationships. This will serve to bridge the information into the Automatic Mapping & Facilities Management System (AM/FM).	O
11. QUERY/REPORTING	
Query/Reporting provides the facilities necessary to support routine and ad hoc requests for information.	O
11.1 Routine Query Support	
Query support provides the facilities necessary to search for information on customers by account number, civic address, service locations, last name, business name, phone number, mailing address, second account name holder, etc.	M
11.2 Ad Hoc Query Support	
Query support provides the facilities necessary to provide information not routinely required such as a search of accounts by SIC code, consumption levels, rate code, business name, location, etc.	O
11.3 Routine Reporting Support	

Routine reporting support provides the facilities necessary to regularly answer predictable questions about selected groups of items such as routes and sequences, budget accounts, pre-authorized payment customers, etc.	M
The routine reports are a set of reports, which can be run with user selection input at any time. Historical reports must be stored and made available for printing for a period of time based on the anticipated need for access/reprinting.	M
11.4 Ad Hoc Reporting Support	
Ad hoc reporting support provides the facilities necessary to easily construct queries, which answer questions about individual or selected groups of items such as accounts by SIC code, consumption levels, rate code, business name, location, etc.	O
The ad hoc reports are created using a tool kit, which can be run with user selection input at any time. Crystal reports are the I-Tek standard at this time.	
12. SYSTEM SUPPORT	
This function provides support and general-purpose services that are utilized by other functional areas of CIS. It includes capabilities such as task queuing through use of the electronic work queue, task re-directing, ad hoc reporting, on-line report viewing and selection, local printing, message broadcasting, etc.	
12.1 Maintain System Security	
System Security provides system administrators the facilities to control system access. For each user ID, it includes functions such as granting system access, defining the boundary of data access and administering levels of access, such as inquiry, update, control, approval, etc., for each business activity. The system must have the capability of restricting access by user to accounts between companies held in a single database.	M
12.2 Maintain System Parameters	
This function provides the user system administrator the facilities to administer all system parameters.	M
System parameters include general operational and functional specific parameters. Some parameters apply to North of Sixty as a whole and others vary between service areas.	M
General operational parameters, such as billing schedule, meter reading schedule, due dates, rate tables, global messaging, plant and community tables, etc., control the day-to-day operations of the system. These parameters must be flexible to meet the specific needs of the individual company even though the accounts are held in a single database.	M
Functional specific parameters are non-static parameters, which support the business functions. Some examples are the validation criteria for data elements, the interest percentage of deposit refund, the default credit rating for new customers, the late payment penalty charge percentage, the number of days after final invoices for reminder notices, etc. These parameters must be flexible to meet the specific needs of the individual company even though the accounts are held in a single database.	M
12.3 Balance System Controls	
Balance and control procedures are established to ensure the system and data integrity.	M

Balances and controls are performed by the system at individual function/subsystem. Out of balance conditions are identified and reported and prompt for action notifications are generated. A procedure manual must be provided defining error reasons and possible solutions. The balance detail reports are also available for on-line viewing.	M
The balance procedures include monetary and control item count balancing. The global control procedures are in place to enforce system operation controls; data validation criteria, system parameters controls, and security access privileges, system activity controls and error correction controls.	M
12.4 System Reporting	
System Reporting provides the facilities to request for ad hoc and production reports and to view reports on-line with the option to print at designated locations. Error and exception reports will be minimized through task queuing.	O
12.5 Audit Trail	
This function provides an audit trail of data added, changed, deleted and transferred. A record of the date, time and the person responsible is maintained for each update to the data. Record of all daily activities including all cash transactions, billing input, adjustments, etc. must be provided on suitable medium such as CD or microfiche.	M
12.6 Manage Data	
The Manage Data function provide the facilities to archive on-line data off-line, recall off-line historical data, purge historical data exceeding retention criteria, recover data after system failure and apply mass updates to data. A facility must be in place to store archived data as system is purged. Currently microfiche is used but is not the preferred medium of choice.	M

APPENDIX B – Technical Feasibility Requirements

TR1-Technical Architecture	Ability to comply with and integrate with ATCO's preferred technical Architecture
TF2-Configuration of workstations	Ability to run on standard hardware and software platforms in use within ATCO Ability to run in a managed workstation infrastructure
TF3-Configuration of Application Servers	Ability to install and run on ATCO's standard application server hardware and software platforms Ability to maintain support for existing and new versions of application server operating system
TF4- Configuration of Database and Database Server	Ability to install and run on ATCO's standard database server hardware and software platforms Provides adequate information that database can be supported by existing staff
TF5- Shared Hosting Environment	Provides adequate protection within the layers the allows this application infrastructure to execute in a shared resource model
TF6- Systems Integration	Provides an interface into the application logic that can be called by other applications Provides an interface into the data layer that can be queried by other applications
TF7- Security	Ability to integrate into existing security infrastructure Supports the use of a common user repository outside of the application Ability to conform to existing security policies and controls
TF8- Redundancy, Backup and Recovery	Ability to integrate into existing backup and recovery tools and processes Ability to integrate with existing Disaster Recovery tools and processes Ability to run in a fault tolerant mode
TF9- Performance and Monitoring	Provides a standard interface or set of tools to monitor health of the application
TF10- Network Communication	Uses standard protocols and technologies for communication between layers of the application Optimized for use in low bandwidth infrastructures
TF11- Configuration, Installation, Distribution and Licensing	Provides standard approaches to installation and configuration of the application on all platforms Provides the tools or flexibility for ATCO to remain license compliant
TF12- Change Management	Vendor provides a well established and reasonable release cycle for updates Application updates can conform to existing ATCO change management guidelines

North of 60 CIS project evaluation

Scenario 3 - ATCO CIS

Option 4 Description

Cost Impact

Assumptions:

1 Financial Parameters

Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	6.60%	52%	3.43%	3.43%
Preferred	0.00%	0%	0.00%	0.00%
Common	9.25%	48%	6.78%	4.44%
TOTALS			10.21%	7.87%

Depreciation Rates:

Transmission	**0.00%**
Distribution	**0.00%**
Communication	**0.00%**
"D" Other	**10.00%**

Source: D. Business Case Assumptions

Income Taxes and Escalation	2006	2007	2008	2009	>= 2010
Federal and Provincial Income Tax			34.50%	34.00%	33.00%
Escalation					
Capital (T&D)		0.0%	0.0%	0.0%	0.0%
O & M (T&D)		5.0%	5.0%	5.0%	5.0%
(50/50 blend of rate of labour & materials)					

Source: 2008 Business Case Assumptions — 2008 Income Taxes: 34.50%

2 All analysis are based on 10 years of costs.

3 Embedded distribution capital and O&M costs are not considered in analysis.

4 Base Year: 2008
In-Service Date: 2008

5 Incremental Capital Spending:

Annual Escalation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	
Compounded Escalation Factor	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	
ISD Index	1	0	0	0	0	0	0	0	0	0	0	0
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter capital expenditures in 2008 dollars	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Distribution Other	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(inflated)	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Cost Before AFUDC (2007$)	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Cost Before AFUDC (Nom$)	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Distribution Other

Opening Balance		$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207
Capital Addition	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RATEBASE	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Total Rate Base

Opening Balance	$0	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207	$1,488,207
Capital Addition	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RATEBASE	$1,488,207	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

7 Incremental Operation and Maintenance Costs:

Annual Escalation Factor	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Compounded Escalation Factor	1.050	1.103	1.158	1.216	1.276	1.340	1.407	1.477	1.551	1.629	1.710	1.796
ISD Index	1	0	0	0	0	0	0	0	0	0	0	0
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

O&M Manual Input (2008$)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Distribution Other O&M	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$0
	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$493,207	$0

Escalated Manually Input O&M (Nom$)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Distribution Other O&M	$517,868	$543,761	$570,949	$599,497	$629,471	$660,945	$693,992	$728,692	$765,126	$803,383	$843,552	$0
	$517,868	$543,761	$570,949	$599,497	$629,471	$660,945	$693,992	$728,692	$765,126	$803,383	$843,552	$0

UCG-YECL-49

Reference: May 27, 2013 Application, page 9-12

YECL provides a listing of 6 projects plus 1 "Other Projects" which make up $779,000 in **2009 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Haines Junction Plant Controls Upgrade	$324,000
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	$153,000
Fish Lake Unit #1 Replacement Wheel	$ 80,000
Fish Lake Incremental Purchase Power	$ 69,000
Fish Lake Control Room Monitor Upgrade	$ 52,000
Swift River Unit #1 Replacement	$ 32,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Haines Junction Plant Controls Upgrade	$324,000
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	$153,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2009 capital expenditures on generation plant projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on generation projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2004-2008 for generation plant projects was $744,000.

UCG-YECL-50

Reference: May 27, 2013 Application, pages 9-13 – 9-15

YECL provides a listing of 27 projects plus 1 "Other Projects less than $20,000" which make up $3,437,000 in **2009 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$969,000
Ingram Subdivision	$717,000
Takhini North Infill	$341,000
Two City Water Wells in Riverdale	$107,000
Hamilton Boulevard Main Infrastructure Extension	$100,000
New Whitehorse Correctional Centre	$ 90,000
Yukon Housing 8-Plex	$ 88,000
Burns Road Lot Development	$ 86,000
General Drafting and Mapping	$ 75,000
City of Whitehorse Public Safety Building	$ 61,000
Ta'an Kwach'an Council Subdivision – Klondike Highway North	$ 60,000
Yukon Government New Airport Parking Area	$ 58,000
Land Rights	$ 56,000
35 Unit Condominium Wann Road	$ 53,000
Yukon Government Army Beach Sewage Lagoon	$ 47,000
Whitehorse Lot 1097	$ 46,000
Lot 1095 Gentain Lane	$ 41,000
Teslin Seniors 8-Plex	$ 40,000
Selkirk First Nation Child Care Center	$ 36,000
Miscellaneous New U/G Services	$ 36,000
Champagne Aishihik First Nation Subdivision	$ 36,000
Yukon Government Carcross Water Front Place	$ 35,000
Watson Lake Line Move	$ 35,000
Takhini Lot 1371	$ 33,000
Yukon Government Carmacks Sewer Treatment Plant	$ 32,000
Whitehorse General Hospital Staff Residence	$ 32,000
Northwestel Communication Tower Hotsprings Road	$ 27,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$969,000
Ingram Subdivision	$717,000
Takhini North Infill	$341,000
Two City Water Wells in Riverdale	$107,000
Hamilton Boulevard Main Infrastructure Extension	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2009 capital expenditures on distribution new extensions projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on distribution new extensions projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2004-2008 for distribution new extensions projects was $2,545,000.

UCG-YECL-51

Reference: May 27, 2013 Application, pages 9-15 – 9-16

YECL provides a listing of 15 projects plus 1 "Other Projects less than $20,000" which make up $1,203,000 in **2009 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Right of Way Widening	$240,000
Arkell Substation Upgrades	$197,000
Hillcrest Subdivision Conversion	$152,000
Wickstrom Road Line Relocation for Whitehorse General Hospital	$ 83,000
Echo Lake Road Upgrade	$ 75,000
9L Reliability Upgrade Squanga Lake Area	$ 51,000
Robinson Substation Upgrade	$ 39,000
Birch Alley Upgrade	$ 32,000
Liard River Crossing	$ 29,000
Whitehorse Airport Conversion	$ 29,000
McDonald Road to Centennial Road Upgrade	$ 24,000
Miscellaneous Pole Replacements	$ 22,000
System Upgrade on Hotsprings River Road	$ 22,000
Watson Lake Hotel Upgrade	$ 20,000
Teslin and Klondike Road Upgrade	$ 20,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Right of Way Widening	$240,000
Arkell Substation Upgrades	$197,000
Hillcrest Subdivision Conversion	$152,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2009 capital expenditures on distribution improvements projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on distribution improvements projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2004-2008 for distribution improvement projects was $2,601,000.

UCG-YECL-52

Reference: May 27, 2013 Application, page 9-16

YECL provides a listing of 4 projects plus 1 "Other Projects" which make up $354,000 in **2009 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Yukon Government Ingram Subdivision Street Lights	$113,000
Takhini North Subdivision	$ 86,000
Ta'an Kwach'an Council Subdivision	$ 54,000
Hamilton Boulevard Extension	$ 41,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for the following project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Yukon Government Ingram Subdivision Street Lights	$113,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2009 capital expenditures on street and sentinel lighting projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2004-2008 for street and sentinel lighting projects was $742,000.

UCG-YECL-53

Reference: May 27, 2013 Application, page 9-16

YECL lists an $80,000 project titled "**Transformers & Regulators**" in 2009 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide a comparative chart of the 2009 capital expenditures on transformers & regulators projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(d) What were the average annual capital expenditures on transformers & regulators projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to WL-YECL-21(k) Attachment 1.

(d) The average annual capital expenditures over the five year period of 2004-2008 for transformers & regulators was $25,618.

UCG-YECL-54

Reference: May 27, 2013 Application, pages 9-16 – 9-17

YECL provides a listing of 4 projects plus 1 "Other Projects" which make up $400,000 in **2009 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Oracle HRxcellence HR Management Software	$117,000
Transportation Equipment	$100,000
Communication Equipment	$ 47,000
Miscellaneous Tools and Instruments	$ 37,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Oracle HRxcellence HR Management Software	$117,000
Transportation Equipment	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) Please provide a comparative chart by project of the 2009 capital expenditures on general property and equipment projects approved by the YUB in YECL's last general rates application proceeding versus actual.

(f) What were the average annual capital expenditures on general property and equipment projects for the period 2004-2008?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to WL-YECL-21(k) Attachment 1.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) Please refer to WL-YECL-21(k) Attachment 1.

(f) The average annual capital expenditures over the five year period of 2004-2008 for general property and equipment projects was $446,000.

UCG-YECL-55

Reference: May 27, 2013 Application, pages 9-18 – 9-19

YECL provides a listing of 10 projects plus 1 "Other Projects" which make up $1,810,000 in **2010 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #2 Penstock Replacement	$486,000
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	$294,000
Destruction Bay Unit #1 Replacement	$275,000
Watson Lake Unit #5 Replacement	$232,000
Fish Lake Unit #1 Spillway	$212,000
Purchase Unit for Pelly Crossing Power Plant	$101,000
Fish Lake Unit #1 Wheel Replacement	$ 45,000
Fish Lake Ditch #3 Drop Box Concrete Upgrade	$ 32,000
Swift River Unit #1 Replacement	$ 25,000
Pelly Crossing Plant Automation	$ 25,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #2 Penstock Replacement	$486,000
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	$294,000
Destruction Bay Unit #1 Replacement	$275,000
Watson Lake Unit #5 Replacement	$232,000
Fish Lake Unit #1 Spillway	$212,000
Purchase Unit for Pelly Crossing Power Plant	$101,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on generation plants projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers generation plant projects from 2010, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2005-2009 for generation plant projects was $714,000.

UCG-YECL-56

Reference: May 27, 2013 Application, pages 9-19 – 9-21

YECL provides a listing of 27 projects plus 1 "Other Projects less than $20,000" which make up $3,397,000 in **2010 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,022,000
Lower Post Health Center 3 Phase Line	$ 733,000
Takhini North Infill	$ 312,000
New Country Residential Subdivision in Haines Junction	$ 105,000
Miscellaneous New U/G Services	$ 86,000
Haines Junction Cultural Centre	$ 74,000
Whitehorse Water Front Place Line Relocation	$ 73,000
Land Rights	$ 66,000
Marsh Lake Landfill	$ 64,000
Yukon Government Core Library	$ 59,000
Yukon Gardens Subdivision	$ 59,000
Stan McGowan 12-Plex	$ 59,000
Yukon College	$ 57,000
35 Unit Condominium Near Mountain Air Subdivision	$ 50,000
10 Units on Range Road	$ 46,000
Main Street Condominium	$ 45,000
Yukon Housing Seniors Housing – Jeckell Street	$ 44,000
Yukon Government - Yukon River Crossing Study and Design	$ 43,000
Lot 1018 Main Street	$ 42,000
Yukon Government Haines Junction Willow Acres Residential Infill	$ 37,000
Grove Street New Lots	$ 35,000
Carcross Landfill	$ 33,000
Whitehorse General Hospital Staff Residence	$ 30,000
Crestview Booster Station	$ 29,000
Lot 1100 Tagish	$ 29,000
Lot 40 Mount Sima	$ 22,000
Little Salmon Carmacks First Nation Healing Centre	$ 21,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,022,000
Lower Post Health Center 3 Phase Line	$ 733,000
Takhini North Infill	$ 312,000
New Country Residential Subdivision in Haines Junction	$ 105,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution new extensions projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution new extensions projects from 2010, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2005-2009 for distribution new extensions projects was $2,834,000.

UCG-YECL-57

Reference: May 27, 2013 Application, pages 9-21 – 9-23

YECL provides a listing of 23 projects plus 1 "Other Projects less than $20,000" which make up $2,251,000 in **2010 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend 34.5kV Substation Distribution Lines	$492,000
Right of Way Widening	$304,000
Hillcrest Subdivision Conversion	$226,000
Takhini North Upgrade	$134,000
Watson Lake 3-Phase System Protection Upgrade	$100,000
Main Steel Alley 4th – 7th Avenue Upgrade	$ 98,000
Test and Treat Program	$ 57,000
Porter Creek Breaker Replacement	$ 54,000
Destruction Bay Distribution Breaker Addition	$ 54,000
Haines Junction Distribution Breaker Addition	$ 51,000
Old Crow Pole Change Outs	$ 46,000
Main Street Alley Upgrade	$ 44,000
Destruction Bay Main Feeder	$ 42,000
North Klondike Grounding Improvements	$ 42,000
Mount Sima Subdivision	$ 42,000
Nordenskiold River Bridge Rerouting	$ 42,000
System Frequency Upgrades at S150 Substation	$ 39,000
4L316 Two Mile Hill Conductor Upgrade	$ 38,000
Klondike Road Improvements	$ 30,000
Whitehorse Copper Rebuild	$ 27,000
Miscellaneous Pole Replacements	$ 26,000
Pole Removal Wickstrom Road	$ 25,000
McIntyre Subdivision Prebuilding Work	$ 22,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend 34.5kV Substation Distribution Lines	$492,000
Right of Way Widening	$304,000
Hillcrest Subdivision Conversion	$226,000
Takhini North Upgrade	$134,000
Watson Lake 3-Phase System Protection Upgrade	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution improvements projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution improvements projects from 2010, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2005-2009 for distribution improvement projects was $2,489,000.

UCG-YECL-58

Reference: May 27, 2013 Application, page 9-23

YECL provides a listing of 5 projects plus 1 "Other Projects less than $20,000" which make up $486,000 in **2010 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Pine Street Light Replacements	$161,000
Whistle Bend Way Light Additions	$ 62,000
Takhini North Subdivision	$ 56,000
Ingram Subdivision Street Lights	$ 50,000
Takhini River Lights	$ 24,000
Street Light Identification	$ 24,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for the following project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Pine Street Light Replacements	$161,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers street and sentinel lighting from 2010, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2005-2009 for street and sentinel lighting projects was $643,000.

UCG-YECL-59

Reference: May 27, 2013 Application, page 9-24

YECL lists a $460,000 project titled "**Meters**" in 2010 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) What were the average annual capital expenditures on meters projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers meters from 2010, there are no forecast costs to compare.

(c) The average annual capital expenditures over the five year period of 2005-2009 for meters was $32,000.

UCG-YECL-60

Reference: May 27, 2013 Application, pages 9-24 – 9-25

YECL provides a listing of 6 projects plus 1 "Other Projects" which make up $985,000 in **2010 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$358,000
Miscellaneous Tools and Instruments	$176,000
Distribution SCADA Equipment	$138,000
Oracle HRxcellence HR Management Software	$103,000
Service Complex Engineering Department Renovations	$ 86,000
Credit Card Pre-Authorized Payment Plan System	$ 67,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$358,000
Miscellaneous Tools and Instruments	$176,000
Distribution SCADA Equipment	$138,000
Oracle HRxcellence HR Management Software	$103,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on general property and equipment projects for the period 2005-2009?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers general property and equipment projects from 2010, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2005-2009 for general property and equipment projects was $452,000.

UCG-YECL-61

Reference: May 27, 2013 Application, pages 9-26 – 9-27

YECL provides a listing of 21 projects plus 1 "other projects" which make up $1,652,000 in **2011 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$717,000
Fish Lake Unit #1 Tailrace Reconstruction	$173,000
Fish Lake Penstock #2 Replacement	$ 70,000
Louise Lake Control Structure Gate Replacement	$ 68,000
Fish Lake Ditch #3 Concrete Upgrade at Drop Box and Bypass	$ 57,000
Fish Lake Dyke Widening	$ 52,000
Ross River Substation Improvements	$ 52,000
Purchase of Used Spare Generator	$ 50,000
Watson Lake Protection Upgrade	$ 48,000
Hobo for Franklin Lake Water Monitoring	$ 36,000
Teslin Programmable Logic Controller (PLC) Replacement	$ 33,000
Watson Lake Unit #5 Replacement	$ 32,000
Stewart Crossing Radio Replacement / Programmable Logic Controller Upgrade	$ 30,000
Fish Lake Unit #1 Spillway	$ 26,000
Hobo Water Monitor for Fish Lake at Range Road	$ 22,000
High Voltage Switching Cubicle and Terminations for Old Crow Plant	$ 20,000
Teslin Plant Combustible Air Intake and Louver Improvements	$ 19,000
Fish Lake Unit #2 Wheel, Shaft, and Bearing Improvements	$ 18,000
Haines Junction Plant Relocation on to Foundation	$ 14,000
Ross River Unit Protection Relay	$ 11,000
Pelly Crossing Plant Automation	$ 10,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$717,000
Fish Lake Unit #1 Tailrace Reconstruction	$173,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on generation plants projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers generation plants projects from 2011, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2006-2010 for generation plant projects was $911,000.

UCG-YECL-62

Reference: May 27, 2013 Application, pages 9-27 – 9-29

YECL provides a listing of 29 projects plus 1 "Other Projects less than $20,000" which make up $6,078,000 in **2011 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,274,000
Whistle Bend Subdivision Stage 1 & 2	$1,242,000
Grizzly Valley New Extension Out of Subdivision	$ 415,000
Water Front Place Line Relocation	$ 385,000
25 Wann Road – 65 Units	$ 343,000
Falcon Ridge Development Stage 4	$ 271,000
New Underground Line Extensions	$ 216,000
Grizzly Valley New Extension In Subdivision	$ 193,000
Ingram 6-Plex Subdivision	$ 165,000
Diamond Ranch Extension	$ 130,000
Yukon Government Haines Junction Willow Acres Residential Infill	$ 124,000
Watson Lake Hospital Upgrade	$ 104,000
Mount Sima T-Bar	$ 86,000
River's Edge Development	$ 81,000
Lot 1368 Mayo Road	$ 80,000
F.H. Collins Secondary School Transformer	$ 72,000
Land Rights	$ 72,000
Carcross Retail Shops	$ 51,000
Yukon Housing Abbeyfield Senior's Residence	$ 48,000
Eagle Eye Subdivision	$ 45,000
6-Plex 1204 Centennial	$ 44,000
Lot 1084 Grizzly Valley	$ 37,000
8-Plex Lot 1127 Hillcrest	$ 35,000
Kulan Area Line Improvements	$ 34,000
Yukon Government Water Treatment Plant	$ 34,000
14th Ave Whitehorse	$ 34,000
Condominium – 602 Main Street	$ 33,000
Lot 1309 Ibex	$ 33,000
Kwanlin Dun First Nation Cultural Centre	$ 31,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$1,274,000
Whistle Bend Subdivision Stage 1 & 2	$1,242,000
Grizzly Valley New Extension Out of Subdivision	$ 415,000
Water Front Place Line Relocation	$ 385,000
25 Wann Road – 65 Units	$ 343,000
Falcon Ridge Development Stage 4	$ 271,000
New Underground Line Extensions	$ 216,000
Grizzly Valley New Extension In Subdivision	$ 193,000
Ingram 6-Plex Subdivision	$ 165,000
Diamond Ranch Extension	$ 130,000
Yukon Government Haines Junction Willow Acres Residential Infill	$ 124,000
Watson Lake Hospital Upgrade	$ 104,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution new extensions projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution new extensions projects from 2011, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2006-2010 for distribution new extensions projects was $3,123,000.

UCG-YECL-63

Reference: May 27, 2013 Application, pages 9-29 – 9-31

YECL provides a listing of 20 projects plus 1 "Other Projects less than $20,000" which make up $4,626,000 in **2011 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Substation	$1,690,000
System Upgrade, Extension of 5L628 to Grizzly Valley	$ 454,000
Laberge Substation Distribution Upgrades	$ 416,000
Right of Way Widening	$ 331,000
PCB Identification and Transformer Change Outs	$ 239,000
5L626 Double Circuit Line to Whistle Bend Substation	$ 200,000
Hotsprings Road Upgrade	$ 190,000
Upgrade Laberge Substation Transformer to 10 MVA	$ 189,000
Whistle Bend 34.5kV Substation Distribution Lines	$ 156,000
Whistle Bend Substation Transformer	$ 127,000
Line Upgrade and Relocation Army Beach	$ 92,000
Miscellaneous Pole Replacements	$ 70,000
Line Upgrade and Relocation Lot 56 Paint Mountain	$ 69,000
System Upgrade 113 Copper Road	$ 53,000
System Frequency Upgrades at S150	$ 37,000
Line Relocation Eagle Way	$ 30,000
Carcross Town Pole Replacements	$ 27,000
Configure Pelly Substation to Yukon Interconnected System	$ 23,000
Centennial Street Upgrades	$ 20,000
Hillcrest Subdivision Conversion	$ 2,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Substation	$1,690,000
System Upgrade, Extension of 5L628 to Grizzly Valley	$ 454,000
Laberge Substation Distribution Upgrades	$ 416,000
Right of Way Widening	$ 331,000
PCB Identification and Transformer Change Outs	$ 239,000
5L626 Double Circuit Line to Whistle Bend Substation	$ 200,000
Hotsprings Road Upgrade	$ 190,000
Upgrade Laberge Substation Transformer to 10 MVA	$ 189,000
Whistle Bend 34.5kV Substation Distribution Lines	$ 156,000
Whistle Bend Substation Transformer	$ 127,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution improvements projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution improvements projects from 2011, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2006-2010 for distribution improvement projects was $2,355,000.

UCG-YECL-64

Reference: May 27, 2013 Application, pages 9-31 – 9-32

YECL provides a listing of 8 projects plus 1 "Other Projects less than $20,000" which make up $1,045,000 in **2011 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 Street Lights	$257,000
Morley and Peel Street Light Replacement	$150,000
Wharf Lighting 1st Ave. Whitehorse	$147,000
Whistle Bend Way Light Additions	$143,000
Trail Lighting along Whitehorse Waterfront to Shipyards Park	$100,000
Boxwood Light Upgrade	$ 44,000
Grizzly Valley Street Lights	$ 27,000
Black Street Additions and Rebuild	$ 20,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 Street Lights	$257,000
Morley and Peel Street Light Replacement	$150,000
Wharf Lighting 1st Ave. Whitehorse	$147,000
Whistle Bend Way Light Additions	$143,000
Trail Lighting along Whitehorse Waterfront to Shipyards Park	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs

incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers street and sentinel lighting from 2011, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2006-2010 for street and sentinel lighting projects was $706,000.

UCG-YECL-65

Reference: May 27, 2013 Application, page 9-32

YECL lists a $199,000 project titled "**Meters**" in 2011 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) What were the average annual capital expenditures on meters projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers meters from 2011, there are no forecast costs to compare.

(c) The average annual capital expenditures over the five year period of 2006-2010 for meters was $121,000.

UCG-YECL-66

Reference: May 27, 2013 Application, page 9-33

YECL lists a $9,000 project titled "**Transformers & Regulators**" in 2011 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) What were the average annual capital expenditures on transformers & regulators projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers transformers & regulators from 2011, there are no forecast costs to compare.

(c) The average annual capital expenditures over the five year period of 2006-2010 for transformer & regulators was $21,000.

UCG-YECL-67

Reference: May 27, 2013 Application, page 9-33

YECL provides a listing of 8 projects plus 1 "Other Projects less than $20,000" which make up $1,330,000 in **2011 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$491,000
Transportation Equipment	$257,000
Demand Side Management Costs	$204,000
Office Furniture	$ 72,000
Miscellaneous Tools and Instruments	$ 67,000
Communication Equipment	$ 49,000
New Cashier System	$ 33,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$491,000
Transportation Equipment	$257,000
Demand Side Management Costs	$204,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on general property and equipment projects for the period 2006-2010?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers general property and equipment projects from 2011, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2006-2010 for general property and equipment projects was $595,000.

UCG-YECL-68

Reference: May 27, 2013 Application, pages 9-34 – 9-35

YECL provides a listing of 18 projects plus 1 "Other Projects less than $20,000" which make up $3,115,000 in **2012 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$1,024,000
Watson Lake Unit #4 Replacement	$ 354,000
Watson Lake Unit #3 Major Overhaul	$ 247,000
Beaver Creek Programmable Logic Control (PLC) Upgrade	$ 206,000
Fish Lake Unit #2 Step-up Transformer	$ 172,000
Fish Lake Unit #2 Turbine Inlet Valve (TIV) Replacement	$ 171,000
Beaver Creek Control Room Separation from Plant	$ 137,000
Carmacks Fuel System Upgrade	$ 100,000
Old Crow Generator Change Out	$ 90,000
Watson Lake Bi-Fuel Project	$ 90,000
Swift River Unit #2 Replacement	$ 53,000
Pelly Crossing Plant New Governors for Automation	$ 53,000
Teslin Fuel System Upgrade	$ 41,000
Ross River Fuel System Upgrade	$ 37,000
Water Pressure Monitor (Hobo) for Louise Lake	$ 37,000
Teslin Programmable Logic Controller (PLC) Replacement	$ 31,000
Destruction Bay Fuel System Upgrade	$ 21,000
Haines Junction Fuel System Upgrade	$ 20,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$1,024,000
Watson Lake Unit #4 Replacement	$ 354,000
Watson Lake Unit #3 Major Overhaul	$ 247,000
Beaver Creek Programmable Logic Control (PLC) Upgrade	$ 206,000
Fish Lake Unit #2 Step-up Transformer	$ 172,000
Fish Lake Unit #2 Turbine Inlet Valve (TIV) Replacement	$ 171,000
Beaver Creek Control Room Separation from Plant	$ 137,000
Carmacks Fuel System Upgrade	$ 100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on generation plants projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers generation plants projects from 2012, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2007-2011 for generation plant projects was $1,114,000.

UCG-YECL-69

Reference: May 27, 2013 Application, pages 9-35 – 9-38

YECL provides a listing of 35 projects plus 1 "Other Projects less than $20,000" which make up $4,919,000 in **2012 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$992,000
Whistle Bend Subdivision Stage 1 & 2	$683,000
Northwestel Fox Point	$308,000
Northwestel Minto	$308,000
Grizzly Valley New Extension In Subdivision	$272,000
Grey Wolf 1583 Wann Road	$198,000
Lot 1146 Crestview Development	$161,000
Mah's Point Condominiums	$193,000
New Underground Line Extensions	$144,000
Lot 405 Takhini	$130,000
Yukon Government Ross River Pole Relocation	$122,000
Yukon Government Tagish Landfill	$104,000
Water Front Place Line Relocation	$100,000
Carcross Tagish First Nation C82B Subdivision	$ 86,000
Hidden Haven	$ 78,000
Daylu Dena 10 Lots Lower Post	$ 74,000
Yukon Government Teslin Pole Moves	$ 67,000
Betty's Haven Shelter Lot 6	$ 65,000
Yukon Government Yukon River Crossing	$ 62,000
Yukon Government Civil Excavations in Watson Lake	$ 62,000
Ingram Subdivision 15 Units	$ 60,000
City of Whitehorse Selkirk Street Pump House #6	$ 58,000
Liard First Nation Lots 123 and 134 2 Mile Subdivision	$ 55,000
New Hangar Condor Road	$ 51,000
F.H. Collins Secondary School Transformer	$ 48,000
Lot 1395 North Klondike Highway	$ 47,000
Kulan Area Line Improvements	$ 41,000

Lot 1014 Alaska Highway South	$ 39,000
Lot 105 Otter Road	$ 35,000
City of Whitehorse Ponderosa Communication Tower	$ 34,000
Falcon Ridge Development Stage 4	$ 34,000
Lots 1095/1096 Grizzly Subdivision	$ 32,000
City of Whitehorse Marwell Reroute	$ 28,000
Yukon Government Mt. Lorne Land Fill	$ 27,000
20 Laberge Road Service Upgrade	$ 26,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$992,000
Whistle Bend Subdivision Stage 1 & 2	$683,000
Northwestel Fox Point	$308,000
Northwestel Minto	$308,000
Grizzly Valley New Extension In Subdivision	$272,000
Grey Wolf 1583 Wann Road	$198,000
Lot 1146 Crestview Development	$161,000
Mah's Point Condominiums	$193,000
New Underground Line Extensions	$144,000
Lot 405 Takhini	$130,000
Yukon Government Ross River Pole Relocation	$122,000
Yukon Government Tagish Landfill	$104,000
Water Front Place Line Relocation	$100,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution new extensions projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution new extensions projects from 2012, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2007-2011 for distribution new extensions projects was $3,852,000.

UCG-YECL-70

Reference: May 27, 2013 Application, pages 9-39 – 9-41

YECL provides a listing of 24 projects plus 1 "Other Projects less than $20,000" which make up $4,018,000 in **2012 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

5L628 Crestview to Mayo Road Corner Double Circuit	$628,000
Shipyards Substation Transformer Failure and Upgrades	$473,000
Whistle Bend Substation	$423,000
PCB Identification and Transformer Change Outs	$401,000
Right of Way Widening	$377,000
Hillcrest Conversion	$252,000
Regulator to North Klondike Highway	$154,000
Test and Treat Program	$153,000
Laberge Substation 34.5kV Conductor Upgrade	$103,000
Whitehorse Elementary School Transformer Upgrade	$ 94,000
Breaker Replacement in Services Substation	$ 84,000
Old Crow 3rd Distribution Breaker	$ 78,000
97 Lewes Boulevard Transformer Upgrade	$ 70,000
Miscellaneous Pole Replacements	$ 60,000
Laberge Substation Upgrade	$ 57,000
Range Road Line Rerouting	$ 56,000
Marsh Lake Substation Upgrade	$ 45,000
Ponderosa Road Vault Addition and Service Upgrade	$ 35,000
Ross River Recloser for S7580	$ 30,000
CRE Breaker Replacement in Lewes Boulevard	$ 30,000
Porter Creek Underground Vaults Replacement	$ 28,000
Whitehorse Service Area Line Clearance Upgrades	$ 25,000
System Improvements Lowe Street	$ 21,000
Marsh Lake Structure Upgrade	$ 21,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

5L628 Crestview to Mayo Road Corner Double Circuit	$628,000
Shipyards Substation Transformer Failure and Upgrades	$473,000
Whistle Bend Substation	$423,000
PCB Identification and Transformer Change Outs	$401,000
Right of Way Widening	$377,000
Hillcrest Conversion	$252,000
Regulator to North Klondike Highway	$154,000
Test and Treat Program	$153,000
Laberge Substation 34.5kV Conductor Upgrade	$103,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution improvements projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers distribution improvements projects from 2012, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2007-2011 for distribution improvement projects was $2,709,000.

UCG-YECL-71

Reference: May 27, 2013 Application, page 9-41

YECL provides a listing of 4 projects plus 1 "Other Projects" which make up $456,000 in **2012 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 Street Lights	$150,000
Yukon Government Lights on 8th Street Watson Lake	$143,000
Black Street – 6th Avenue Escarpment	$ 37,000
Yukon Government Grizzly Valley Street Lights	$ 33,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 Street Lights	$150,000
Yukon Government Lights on 8th Street Watson Lake	$143,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers street and sentinel lighting projects from 2012, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2007-2011 for street and sentinel lighting projects was $726,000.

UCG-YECL-72

Reference: May 27, 2013 Application, page 9-42

YECL lists a $283,000 project titled "**Meters**" in 2012 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) What were the average annual capital expenditures on meters projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers meters from 2012, there are no forecast costs to compare.

(c) The average annual capital expenditures over the five year period of 2007-2011 for meters was $145,000.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

UCG-YECL-73

Reference: May 27, 2013 Application, page 9-42

YECL lists a $34,000 project titled "**Transformers & Regulators**" in 2012 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in this project, when these costs were incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) If this project was identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) What were the average annual capital expenditures on transformers & regulators projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers transformers & regulators from 2012, there are no forecast costs to compare.

(c) The average annual capital expenditures over the five year period of 2007-2011 for transformer & regulators was $22,000.

UCG-YECL-74

Reference: May 27, 2013 Application, pages 9-42 – 9-43

YECL provides a listing of 9 projects plus 1 "Other Projects" which make up $1,766,000 in **2012 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs incurred in the following projects, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$688,000
Transportation Equipment	$421,000
Miscellaneous Tools and Instruments	$166,000
Demand Side Management Costs	$143,000
Downtown Office Interior Renovations	$ 62,000
Windows 7 Upgrades	$ 61,000
Whitehorse Service Complex HVAC Replacement	$ 59,000
Communication Equipment	$ 57,000
Office Furniture	$ 24,000

(b) For all of these projects that were identified in YECL's 2008-2009 General Rates Application, please compile a comparison of forecast costs versus actual using the breakdown provided in response to part (a).

(c) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$688,000
Transportation Equipment	$421,000
Miscellaneous Tools and Instruments	$166,000
Demand Side Management Costs	$143,000

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs incurred for each project, when these costs were incurred and when these projects are proposed

to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on general property and equipment projects for the period 2007-2011?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Yukon Electrical's 2008-2009 GRA only provided capital forecasts up to the 2009 year. Since this IR covers general property and equipment projects from 2012, there are no forecast costs to compare.

(c) Please refer to YUB-YECL-61.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2007-2011 for general property and equipment projects was $787,000.

UCG-YECL-75

Reference: May 27, 2013 Application, pages 9-44 – 9-45

YECL provides a listing of 20 projects plus 1 "Other Projects" which make up $6,696,000 in **2013 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$2,167,000
Watson Lake Unit #4 Replacement	$1,120,000
500kW Mobile Generator	$ 750,000
Beaver Creek Unit #2 Replacement	$ 600,000
Watson Lake Bi-Fuel Project	$ 363,000
Fish Lake Dyke Upgrade	$ 300,000
Old Crow Plant Expansion	$ 300,000
Watson Lake Unit # 6 Major Overhaul	$ 250,000
Beaver Creek Programmable Logic Control (PLC) Upgrade	$ 180,000
New 250kW Mobile Generator	$ 175,000
Destruction Bay Plant Foundation Refurbishment	$ 150,000
Fish Lake Unit #2 SCADA	$ 50,000
Fish Lake Unit #2 Penstock Improvements	$ 40,000
Fish Lake Unit #2 Siding Replacement	$ 35,000
Fish Lake Head Pond #2 Spillway Upgrade	$ 30,000
Swift River Unit #2 Replacement	$ 30,000
Fish Lake Unit #2 Vibration Monitoring	$ 20,000
Fish Lake Unit #1 Fiber Communication from Head Pond to Unit	$ 20,000
Fish Lake Unit #2 Building Improvements	$ 20,000
Fish Lake Unit #1 Spillway Diversion Structure	$ 20,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Unit #1 Turbine and Building Replacement	$2,167,000
Watson Lake Unit #4 Replacement	$1,120,000
500kW Mobile Generator	$ 750,000
Beaver Creek Unit #2 Replacement	$ 600,000

Watson Lake Bi-Fuel Project	$ 363,000
Fish Lake Dyke Upgrade	$ 300,000
Old Crow Plant Expansion	$ 300,000
Watson Lake Unit # 6 Major Overhaul	$ 250,000
Beaver Creek Programmable Logic Control (PLC) Upgrade	$ 180,000
New 250kW Mobile Generator	$ 175,000
Destruction Bay Plant Foundation Refurbishment	$ 150,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on generation plants projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2008-2012 for generation plant projects was $1,642,000.

UCG-YECL-76

Reference: May 27, 2013 Application, pages 9-46 – 9-47

YECL provides a listing of 8 projects plus 1 "Other Projects less than $20,000" which make up $5,149,000 in **2013 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$3,625,000
New Underground Line Extensions	$ 600,000
Service to proposed City of Whitehorse Municipal Services Building	$ 420,000
Land Rights	$ 190,000
General Drafting and Mapping	$ 80,000
Yukon Government Teslin Sawmill Subdivision	$ 75,000
Lot 11 Marion Crescent	$ 53,000
Lot 1000 Airport Road	$ 53,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$3,625,000
New Underground Line Extensions	$ 600,000
Service to proposed City of Whitehorse Municipal Services Building	$ 420,000
Land Rights	$ 190,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs to be

incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution new extensions projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2008-2012 for distribution new extensions projects was $4,215,000.

UCG-YECL-77

Reference: May 27, 2013 Application, pages 9-47 – 9-49

YECL provides a listing of 21 projects plus 1 "Other Projects less than $20,000" which make up $4,137,000 in **2013 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

McIntyre Subdivision Replacement Stage 1	$475,000
Downtown Whitehorse 4L313 Lambert Street to Elliot Street – Replace with UG	$424,000
Right of Way Widening	$374,000
Tagish 5L600 Rebuild	$300,000
Hillcrest Conversion	$275,000
Miscellaneous Distribution Pole Replacement	$260,000
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	$250,000
Crestview to Mayo Road 5L628 Upgrade to 266 MCM	$250,000
Old Alaska Highway Bypass	$248,000
PCB Identification and Transformer Change Outs	$175,000
Hotsprings Road Main Line Relocation and Upgrade	$325,000
Test and Treat Program	$110,000
Jack Hulland School Upgrades	$100,000
Carmacks North Main Line Rebuild	$100,000
Pelly Crossing Substation Fence	$100,000
Whitehorse Asset Management – Create a Pole Database	$ 75,000
Whitehorse Area Line Clearance Upgrades	$ 65,000
Teslin Area Pole Upgrades	$ 53,000
Teslin Sawmill Road Upgrade for New Subdivision	$ 38,000
Whitehorse Safety Code Corrections	$ 30,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

McIntyre Subdivision Replacement Stage 1	$475,000
Downtown Whitehorse 4L313 Lambert Street to Elliot Street – Replace with UG	$424,000

Right of Way Widening	$374,000
Tagish 5L600 Rebuild	$300,000
Hillcrest Conversion	$275,000
Miscellaneous Distribution Pole Replacement	$260,000
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	$250,000
Crestview to Mayo Road 5L628 Upgrade to 266 MCM	$250,000
Old Alaska Highway Bypass	$248,000
PCB Identification and Transformer Change Outs	$175,000
Hotsprings Road Main Line Relocation and Upgrade	$325,000
Test and Treat Program	$110,000
Jack Hulland School Upgrades	$100,000
Carmacks North Main Line Rebuild	$100,000
Pelly Crossing Substation Fence	$100,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(e) What were the average annual capital expenditures on distribution improvements projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

(e) The average annual capital expenditures over the five year period of 2008-2012 for distribution improvement projects was $3,099,000.

UCG-YECL-78

Reference: May 27, 2013 Application, page 9-50

YECL provides a listing of 2 projects plus 1 "Other Projects" which make up $420,000 in **2013 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous Street Light Replacements	$330,000
Whistle Bend Stage 1 & 2 & 3 Street Lights	$ 75,000

(b) Please provide the business case for the following project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous Street Light Replacements	$330,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(d) What were the average annual capital expenditures on street and sentinel lighting projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

(d) The average annual capital expenditures over the five year period of 2008-2012 for street and sentinel lighting projects was $636,000.

UCG-YECL-79

Reference: May 27, 2013 Application, page 9-50

YECL lists a $600,000 project titled "**Meters**" in 2013 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in this project, when these costs will be incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) What were the average annual capital expenditures on meters projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) The average annual capital expenditures over the five year period of 2008-2012 for meters was $195,000.

UCG-YECL-80

Reference: May 27, 2013 Application, page 9-50

YECL lists a $10,000 project titled "**Transformers & Regulators**" in 2013 capital expenditures.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in this project, when these costs will be incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(b) What were the average annual capital expenditures on transformers & regulators projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) The average annual capital expenditures over the five year period of 2008-2012 for transformers & regulators was $25,000.

UCG-YECL-81

Reference: May 27, 2013 Application, pages 9-51 – 9-53

YECL provides a listing of 19 projects plus 1 "Other Projects" which make up $3,270,000 in **2013 capital expenditures on general property and equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$650,000
Downtown Office Building Envelope Upgrades	$600,000
Transportation Equipment	$424,000
Display Change to Yukon Electrical Billing Statements	$259,000
Windows 7 Upgrades	$146,000
Whitehorse Service Complex Pole Storage	$150,000
Demand Side Management Costs	$135,000
E-Post Billing	$125,000
Miscellaneous Tools and Instruments	$117,000
Whitehorse Service Complex Parking Lot Expansion and Improvements	$100,000
Downtown Office Interior Renovations	$100,000
Whitehorse Service Complex Operations Department & Mtg Room Renovations	$ 80,000
Whitehorse Service Complex – Roof/Insulation, Reception Area, etc.	$ 70,000
Field Collection System	$ 55,000
Office Furniture	$ 44,000
Field Collection System – Report Development (ITBS)	$ 43,000
Yukon Electric Website Improvements	$ 35,000
New Cashier System	$ 25,000
Whitehorse Service Complex – Fence Extension	$ 20,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Water Licence Renewal	$650,000
Downtown Office Building Envelope Upgrades	$600,000
Transportation Equipment	$424,000

Display Change to Yukon Electrical Billing Statements	$259,000
Windows 7 Upgrades	$146,000
Whitehorse Service Complex Pole Storage	$150,000
Demand Side Management Costs	$135,000
E-Post Billing	$125,000
Miscellaneous Tools and Instruments	$117,000
Whitehorse Service Complex Parking Lot Expansion and Improvements	$100,000
Downtown Office Interior Renovations	$100,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(d) What were the average annual capital expenditures on general property and equipment projects for the period 2008-2012?

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

(d) The average annual capital expenditures over the five year period of 2008-2012 for general property and equipment projects was $998,000.

UCG-YECL-82

Reference: May 27, 2013 Application, pages 9-54 – 9-55

YECL provides a listing of 15 projects plus 1 "Other Projects" which make up $7,759,000 in **2014 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Fish Lake Ditch #3 Diversion Structure Replacement	$1,640,000
Fish Lake Dyke Upgrade	$1,420,000
Destruction Bay Unit #2 Replacement	$ 600,000
Old Crow Unit #4 Addition	$ 500,000
Watson Lake Bi-Fuel Project	$ 372,000
Destruction Bay Unit #3 Replacement	$ 450,000
Destruction Bay Programmable Logic Controller Upgrade	$ 300,000
Watson Lake Unit #5 Major Overhaul	$ 200,000
Watson Lake Replace ABB 5HK Breakers	$ 180,000
Stewart Crossing Plant Improvements	$ 120,000
Fish Lake Unit #1 Spillway Diversion Structure	$ 100,000
Stewart Crossing Plant Building Insulation	$ 60,000
Ross River Replace ABB 5HK Breakers	$ 45,000
Fish Lake Unit #2 Head Pond Low Level Outlet Pipe	$ 30,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Old Crow Plant Expansion	$1,650,000
Fish Lake Ditch #3 Diversion Structure Replacement	$1,640,000
Fish Lake Dyke Upgrade	$1,420,000
Destruction Bay Unit #2 Replacement	$ 600,000
Old Crow Unit #4 Addition	$ 500,000
Watson Lake Bi-Fuel Project	$ 372,000
Destruction Bay Unit #3 Replacement	$ 450,000
Destruction Bay Programmable Logic Controller Upgrade	$ 300,000
Watson Lake Unit #5 Major Overhaul	$ 200,000

Watson Lake Replace ABB 5HK Breakers	$ 180,000
Stewart Crossing Plant Improvements	$ 120,000
Fish Lake Unit #1 Spillway Diversion Structure	$ 100,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

UCG-YECL-83

Reference: May 27, 2013 Application, pages 9-55 – 9-56

YECL provides a listing of 4 projects plus 1 "Other Projects less than $20,000" which make up $5,370,000 in **2014 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$2,900,000
Whistle Bend Stage 3	$1,200,000
New Underground Line Extensions	$1,000,000
Land Rights	$ 190,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$2,900,000
Whistle Bend Stage 3	$1,200,000
New Underground Line Extensions	$1,000,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

UCG-YECL-84

Reference: May 27, 2013 Application, pages 9-56 – 9-58

YECL provides a listing of 14 projects plus 1 "Other Projects less than $20,000" which make up $4,638,000 in **2014 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whitehorse 5L628 and New 34.5kV Build	$1,890,000
Downtown Whitehorse 25kV Conversion	$ 450,000
Right of Way Widening	$ 389,000
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	$ 300,000
Miscellaneous Distribution Pole Replacement	$ 260,000
McIntyre Subdivision Replacement Stage 1	$ 250,000
Hillcrest Conversion	$ 250,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	$ 250,000
Test and Treat Program	$ 120,000
Marwell Lot 14 Transformer Upgrade	$ 100,000
Riverdale Lewes Substation 25kV Transformer	$ 100,000
PCB Identification and Transformer Change Outs	$ 100,000
Whitehorse Asset Management – Create a Pole Database	$ 75,000
Whitehorse Area Line Clearance Upgrades	$ 70,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whitehorse 5L628 and New 34.5kV Build	$1,890,000
Downtown Whitehorse 25kV Conversion	$ 450,000
Right of Way Widening	$ 389,000
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	$ 300,000
Miscellaneous Distribution Pole Replacement	$ 260,000
McIntyre Subdivision Replacement Stage 1	$ 250,000
Hillcrest Conversion	$ 250,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	$ 250,000

Test and Treat Program	$ 120,000
Marwell Lot 14 Transformer Upgrade	$ 100,000
Riverdale Lewes Substation 25kV Transformer	$ 100,000
PCB Identification and Transformer Change Outs	$ 100,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

UCG-YECL-85

Reference: May 27, 2013 Application, pages 9-58 – 9-59

YECL provides a listing of 2 projects plus 1 "Other Projects" which make up $945,000 in **2014 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 & 3 Street Lights	$450,000
Miscellaneous Street Light Replacements	$450,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Whistle Bend Stage 1 & 2 & 3 Street Lights	$450,000
Miscellaneous Street Light Replacements	$450,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

UCG-YECL-86

Reference: May 27, 2013 Application, page 9-59

YECL provides a listing of 2 projects which make up $1,630,000 in **2014 capital expenditures on meters projects.**

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Automated Meter Reading (AMR)	$1,580,000
Replacement Meters	$ 50,000

(b) Please provide the business case for the following project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Automated Meter Reading (AMR)	$1,580,000

(c) Please confirm whether the project listed in part (b) has been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

UCG-YECL-87

Reference: May 27, 2013 Application, page 9-59

YECL lists a $10,000 project titled "**Transformers & Regulators**" in 2014 capital expenditures.

Request:

Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in this project, when these costs will be incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

UCG-YECL-88

Reference: May 27, 2013 Application, pages 9-59 – 9-60

YECL provides a listing of 7 projects plus 1 "Other Projects" which make up $2,066,000 in **2014 capital expenditures on general property & equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$995,000
Demand Side Management Costs	$522,000
Old Crow Staff Accommodations	$100,000
Watson Lake Power Plant Connection to Town Water Supply	$100,000
Whitehorse Various Service Complex Renovations	$100,000
Miscellaneous Tools and Instruments	$167,000
Communication Equipment	$ 11,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Transportation Equipment	$995,000
Demand Side Management Costs	$522,000
Old Crow Staff Accommodations	$100,000
Watson Lake Power Plant Connection to Town Water Supply	$100,000
Whitehorse Various Service Complex Renovations	$100,000
Miscellaneous Tools and Instruments	$167,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

UCG-YECL-89

Reference: May 27, 2013 Application, page 9-61

YECL provides a listing of 6 projects which make up $5,900,000 in **2015 capital expenditures on generation plants projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Carcross 2MVA Generation Standby Unit	$3,000,000
Watson Lake Unit #2 Replacement	$1,350,000
Beaver Creek Unit #1 Replacement	$ 600,000
Old Crow Unit #3 Replacement	$ 500,000
Watson Lake Unit #1 Major Overhaul	$ 250,000
Watson Lake Replace ABB 5HK Breakers	$ 200,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Carcross 2MVA Generation Standby Unit	$3,000,000
Watson Lake Unit #2 Replacement	$1,350,000
Beaver Creek Unit #1 Replacement	$ 600,000
Old Crow Unit #3 Replacement	$ 500,000
Watson Lake Unit #1 Major Overhaul	$ 250,000
Watson Lake Replace ABB 5HK Breakers	$ 200,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

UCG-YECL-90

Reference: May 27, 2013 Application, page 9-62

YECL provides a listing of 3 projects plus 1 "Other Projects less than $20,000" which make up $5,570,000 in **2015 capital expenditures on distribution new extensions projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$4,300,000
New Underground Line Extensions	$1,000,000
Land Rights	$ 190,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Miscellaneous O/H Services – Various Subdivisions	$4,300,000
New Underground Line Extensions	$1,000,000
Land Rights	$ 190,000

(c) Please confirm whether any of the projects listed in part (b) have been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

(d) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects less than $20,000" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

(d) Please refer to YUB-YECL-61.

UCG-YECL-91

Reference: May 27, 2013 Application, pages 9-62 – 9-65

YECL provides a listing of 21 projects plus 1 "Other Projects less than $20,000" which make up $4,084,000 in **2015 capital expenditures on distribution improvements projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Downtown Whitehorse 25kV Conversion	$450,000
Right of Way Widening	$405,000
Whitehorse Hotsprings Road 3 Phase Conversion	$363,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	$350,000
Takhini/Marwell Completion of Mountain Air Subdivision	$300,000
Tagish 5L600 Rebuild	$276,000
Miscellaneous Distribution Pole Replacement	$260,000
MacDonald Road Pole Change	$250,000
Riverdale Line 4L317 Tagish Road	$250,000
Lewes Lake Substation Conversion	$146,000
Whitehorse Airport Hanger D Area Rebuild	$140,000
Test and Treat Program	$130,000
Upper Liard – Replace Liard River Crossing	$100,000
Watson Lake Underground Subdivision Replacement	$100,000
PCB Identification and Transformer Change Outs	$100,000
McLintock Substation Upgrade	$ 90,000
Spirit Lake Substation Upgrade	$ 88,000
Grey Mountain 4L320 Tie Upgrade	$ 65,000
Deep Creek Subdivision Connection to Whitehorse Distribution	$ 60,000
Stewart Crossing West Town Conversion	$ 60,000
Upgrade of S2278	$ 45,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Downtown Whitehorse 25kV Conversion	$450,000
Right of Way Widening	$405,000

Whitehorse Hotsprings Road 3 Phase Conversion	$363,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	$350,000
Takhini/Marwell Completion of Mountain Air Subdivision	$300,000
Tagish 5L600 Rebuild	$276,000
Miscellaneous Distribution Pole Replacement	$260,000
MacDonald Road Pole Change	$250,000
Riverdale Line 4L317 Tagish Road	$250,000
Lewes Lake Substation Conversion	$146,000
Whitehorse Airport Hanger D Area Rebuild	$140,000
Test and Treat Program	$130,000
Upper Liard – Replace Liard River Crossing	$100,000
Watson Lake Underground Subdivision Replacement	$100,000
PCB Identification and Transformer Change Outs	$100,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as “Other Projects less than $20,000” as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

UCG-YECL-92

Reference: May 27, 2013 Application, page 9-66

YECL provides a listing of 2 projects which make up $813,000 in **2015 capital expenditures on street and sentinel lighting projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

New Street Light Installations	$483,000
Street Light Replacements	$330,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

New Street Light Installations	$483,000
Street Light Replacements	$330,000

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

UCG-YECL-93

Reference: May 27, 2013 Application, page 9-66

YECL provides a listing of 2 projects which make up $2,333,000 in **2015 capital expenditures on meters projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Automated Meter Reading (AMR)	$2,283,000
Replacement of Meters and New Installations	$ 50,000

(b) Please provide the business case for the following project per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Automated Meter Reading (AMR)	$2,283,000

(c) Please confirm whether the project listed in part (b) has been submitted to the Yukon government or the YUB to review under Part 3 of the *Public Utilities Act*. If not, please explain why not.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) No projects in part (b) have been submitted to the Yukon government or the YUB for review under Part 3 of the *Public Utilities Act* because Yukon Electrical is seeking approval from the YUB for all capital projects as a part of this Application. Yukon Electrical is not aware of a legislative requirement to have this project also reviewed pursuant to Section 3 of the Public Utilities Act.

UCG-YECL-94

Reference: May 27, 2013 Application, page 9-66

YECL lists a $10,000 project titled "**Transformers & Regulators**" in 2015 capital expenditures.

Request:

Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in this project, when these costs will be incurred and when this project is proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

UCG-YECL-95

Reference: May 27, 2013 Application, pages 9-66 – 9-67

YECL provides a listing of 7 projects plus 1 "Other Projects" which make up $2,110,000 in **2015 capital expenditures on general property & equipment projects**.

Request:

(a) Please provide a detailed description and detailed breakdown of the total costs forecast to be incurred in the following projects, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet:

Demand Side Management Costs	$730,000
Replacement of Unit 989 – 1995 Hot Line Bucket Truck	$450,000
Transportation Equipment	$400,000
Whitehorse Service Complex Yard Extension	$300,000
Miscellaneous Tools and Instruments	$115,000
Office Furniture	$ 34,000
Communication Equipment	$ 12,000

(b) Please provide the business case for each of the following projects per the expectations of business cases as outlined in Board Order 2009-8. Please provide the supporting analyses in an Excel spreadsheet:

Demand Side Management Costs	$730,000
Replacement of Unit 989 – 1995 Hot Line Bucket Truck	$450,000
Transportation Equipment	$400,000
Whitehorse Service Complex Yard Extension	$300,000
Miscellaneous Tools and Instruments	$115,000

(c) Pursuant to Board Order 2009-2, please provide an itemized list of miscellaneous capital expenditures listed as "Other Projects" as well as a detailed description and detailed breakdown of the total costs to be incurred for each project, when these costs will be incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

Response:

(a) Please refer to YUB-YECL-61 Attachment 1 and Attachment 2 for the overview and details of the capital material Yukon Electrical has provided to allow for the testing of this Application.

(b) Please refer to YUB-YECL-61.

(c) Please refer to YUB-YECL-61.

UCG-YECL-96

Reference: May 27, 2013 Application, Schedule 10.1

YECL is anticipating that its Utility Earnings Before Tax will increase by 45% in 2013 (over 2012), by another 32% in 2014 (over 2013) and by another 13% in 2015 (over 2014). By the time 2015 is ended, YECL is expecting its Utility earnings Before tax to increase by 117% over 2012 levels.

Request:

(a) Please provide a detailed explanation for why YECL's Utility Earnings Before Tax will increase at such an alarming rate between 2012 and 2015.

(b) Please provide a detailed explanation for the changes in YECL's CCA deduction between 2012 and 2015.

Response:

(a) Utility Earnings Before Tax is the sum of the Return on Common Stock, as calculated on Schedule 8.1 of the Application for each test year, and the Income Tax Provision, as calculated on Schedule 10.1 of the Application for each test year. As the Return on Common Stock is growing each year due to growth in rate base and the increase in the equity ratio from 40% to 44% for 2013-2015, the Utility Earnings Before Tax is also increasing between 2012 and 2015.

(b) The change in the CCA deduction is a function of: 1) undepreciated capital cost at the opening of the year plus the current year gross capital additions (subject to the half-year rule for the CCA claim); 2) reductions to gross capital adds, which include construction contributions and fully-deductible capitalized costs, as well as various other minor reductions; and 3) the mix of assets put into service as each asset CCA class has a different % rate.

As Yukon Electrical's capital additions are growing through the period 2012-2015, the CCA deduction is also increasing in that period.

UCG-YECL-97

Reference: May 27, 2013 Application, Section 11, Attachment 2

In response to YUB direction in its Decision 2009-2, YECL has provided details on the non-labour inflation rates used by 6 other utilities. Half of the utilities referenced by YECL are affiliates. YECL refers to this as a response to the YUB's request "to provide a study that compares what other utilities use as a basis for non-labour inflation rates".

May 27, 2013 Application, pages 1-6 – 1-7

YECL has assumed non-labour inflation rates of 1.9%, 2.0% and 2.1% for 2013, 2014 and 2015 respectively in its Application. For 2013, the proposed non-labour inflation rate is based on 50% of forecast Alberta inflation and 50% of forecast Yukon inflation. For 2014 and 2015, no forecast of Yukon inflation was available so the non-labour inflation rates applied by YECL are based on 50% of forecast Alberta inflation and 50% of forecast British Columbia inflation.

Request:

(a) Please explain why YECL's "study" did not include analysis included in a report released in October 2012 by the Ontario Energy Board (Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach) which notes that to the extent practicable, non-labour prices should be indexed by distribution industry-specific indices.

(b) What non-labour inflation rates are currently used by FortisBC Utilities, BC Hydro, Manitoba Hydro, NWT Power Corporation, SaskPower, ENMAX, Nova Scotia Power, New Brunswick Power and Qulliq Energy Corporation? Please provide reference material related to these rates.

(c) Please provide the sources of the non-inflation rates from Alberta, Yukon and British Columbia used by YECL to determine their proposed non-labour inflation rates.

(d) Given that YECL's "study" identified non-labour inflation rates used by utilities, please explain why YECL did not use one or more of these regulator-approved rates to determine its proposed non-labour inflation rates.

Response:

(a) In accordance with the Board direction, the purpose of the study was to provide information on what other utilities use as a basis for non-labour inflation rates. The study filed by Yukon Electrical on pages 11-15 and 11-16 of its Application shows that six utilities in Alberta and the Northwest Territories use CPI as a basis to forecast non-labour inflation rates, and that both the AUC and NWTPUB have approved the use of CPI to forecast inflation. While the results of the study are not exhaustive, the results show Yukon Electrical's pragmatic approach to forecasting inflation is consistent with approaches used and approved in neighbouring regulatory jurisdictions.

(b) Please refer to UCG-YECL-97(b) Attachment 1.

(c) Please refer to UCG-YECL-97(c) Attachment 1.

(d) Yukon Electrical based its non-labour inflation forecast on the best and most up-to-date information available at the time of filing. The regulator-approved rates quoted in the study were based on AUC and NWTPUB Decisions from 2011 and 2012, which was not the most current information available when Yukon Electrical filed its Application.

Utility	**Non-Labour Inflation Rate**	**Link**
Fortis BC Inc.	2013: 1.9%	Tab 4 Cost of Service, Page 43 of "FortisBC Inc. Application for Approval of 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan" Page 70 of "British Columbia Utilities Commission Order Number G-110-12"
BC Hydro	2013: 2.1% 2014: 2.1%	Page 5-11 of "British Columbia Hydro and Power Authority (BC Hydro) F2012 to F2014 Revenue Requirements Application"
Manitoba Hydro	Unknown	"Manitoba Hydro 2012/13 & 2013/14 General Rate Application" reviewed. This Application includes information about Canadian CPI for 2012/13 and 2013/14 and a comparison of the growth in Manitoba Hydro's growth in OM&A costs to CPI over the same period, but does not state what inflation rate is used by the utility in forecasting its non-labour costs.
NWT Power Corporation	2013/14: 2%	Page 76 of "Decision 1-2013 of The Public Utilities Board of the Northwest Territories"
SaskPower	2013: 2.0%	SaskPower's 2013 General Rate Application does not specify what non-labour inflation rate was used. However, page 20 of the "Forkast Consulting Independent Review of the SaskPower 2013 Rate Application" does state the inflation rate assumption.
ENMAX	Unknown	ENMAX is under Performance Based Regulation beginning in 2013. Therefore, ENMAX was not required to file a rate application for 2013 so no current inflation rate is available.
Nova Scotia Power	2013: 2.3%	Attachment 1, Pages 9 of 60 and 10 of 60 of the "NS Power 2013 General Rate Application"
New Brunswick Power	Unknown	Upon review of the NB Power and New Brunswick Energy & Utilities Board websites, no information regarding the current inflation rate used by NB Power could be located.
Qulliq Energy Corporation	Unknown	Upon review of the Qulliq Energy Corproation and Utility Rates Review Council of Nunavut websites, no information regarding the current inflation rate used by Qulliq could be located.

	2013 Forecast	2014 Forecast	2015 Forecast
Alberta CPI			
Bank of Montreal (Mar 1/13)	1.3	2.0	
CIBC World Markets (Jan 31/13)	1.1	2.4	
Conference Board of Canada (Feb 22, 2013)	1.8	2.2	
Global Insight (Feb 13/13)	1.9	2.1	2.2
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	2.4	2.4	
Alta Gov't Budget 2013 (Mar 8, 2013)	1.8	1.8	1.8
Average	**1.7**	**2.1**	**2.0**
Yukon CPI			
Yukon Gov't (Yukon Econ Development, Feb 5, 2013)	**2.0**		
British Columbia CPI			
Bank of Montreal (Mar 1/13)	1.1		
CIBC World Markets (Jan 31/13)	1.7		
Conference Board of Canada (Feb 22, 2013)	0.6	1.9	2.2
Global Insight (Feb 13/13)	1.0	1.9	2.0
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	0.6	1.9	2.2
BC Gov't Budget 2012 (Feb 19, 2013)	1.5	2	2.1
Average	**1.1**	**1.9**	**2.1**
Yukon Electrical Other Inflation Forecast	**1.9**	**2.0**	**2.1**

UCG-YECL-98

Reference: May 27, 2013 Application, Section 11, Attachment 6

In response to YUB directive, YECL states that it has participated in a joint government and utilities working group, led by the Government of Yukon, which was established to develop an IPP policy.

Request:

(a) Please provide details on how and when the referenced working group was established in light of the YUB's direction in February 2009.

(b) Please provide details on how often the working group has met since its formation and how often information / positions / comments have been exchanged.

(c) Please provide a copy of all materials and positions authored by YECL that have been contributed to this consultation process.

Response:

(a) The Yukon Territorial Government began background work on the development of an Independent Power Production Policy in late 2008 and formed a working group with Yukon Electrical and Yukon Energy to begin drafting a policy in the first quarter of 2009.

The structure of this group includes a Steering Committee made up of senior membership from both utilities. The Yukon Government gives direction to the working group, which is also made up of members from all three parties. This policy initiative is being led by the Yukon Government.

(b) As requested by the Yukon Government, Yukon Electrical has met as part of this working group. During the key drafting stages of the IPP Policy, this group has met as often as every two weeks. The policy is currently being reviewed internally by the Yukon Government in advance of it being released for public consultation.

(c) Yukon Electrical has not authored formal positions to the process, but rather, has contributed expertise and information as requested by the Yukon Government. As such, Yukon Electrical has no authored positions to provide.

UCG-YECL-99

Reference: May 27, 2013 Application, Business Case #1

Fish Lake Unit #2 Penstock Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #1 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) This project as completed in 2011.

UCG-YECL-100

Reference: May 27, 2013 Application, Business Case #2

Fish Lake Unit #1 Turbine and Building Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #2 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-101

Reference: May 27, 2013 Application, Business Case #3

Watson Lake Unit #4 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #3 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-102

Reference: May 27, 2013 Application, Business Case #4

500 kW Mobile Generator

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #4 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-103

Reference: May 27, 2013 Application, Business Case #5

Beaver Creek Unit #2 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #5 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-104

Reference: May 27, 2013 Application, Business Case #6

Watson Lake Bi-Fuel Project

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #6 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Business Case #6 summarizes the initiative for Yukon Electrical to deliver environmental benefits that reduce the dependency of Watson Lake with a view to reduce the cost of power production from diesel-fueled generating facilities. This Business Case includes the following:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

Preliminary engineering estimates as of July 2012 indicated that approximately 50% of diesel fuel could be displaced on average basis with the bi-fuel technology with a maximum up to 70%. Project costs are forecast to be $675,000 for phase 1 and $372,000 for phase 2. The anticipated fuel costs in phases 1 and 2 were $1.05 per litre diesel equivalent (LDE) and $0.85/LDE, respectively.

For economic analysis information including assumptions please refer to YUB-YECL-42(a).

The risks of proceeding with the chosen alternative are considered low. Isolated power generation offers positive economic and environmental opportunities that can be realized by using natural gas in displacement of diesel.

Relatively simple technology exists to modify stationary reciprocating diesel engines to utilize supplemental amounts of natural gas. Off the shelf “Bi-Fuel” modification kits are currently available. These Bi-Fuel kits allow natural gas to be added to the engine’s air intake upstream of the turbocharger. Risks related to existing generating equipment are low as equipment manufacturers are using this technology. The amount of natural gas supplementation is controlled by automatic engine feedback controls.

Risks related to the high cost of diesel is mitigated introducing an additional fuel type and by having the ability to vary the amount of each fuel used. Should there be a supply or cost issue with respect to natural gas, reverting back to 100% diesel is an option.

A phased implementation approach to the project allows a controlled assessment of the chosen alternative. Should the project not prove successful, Yukon Electrical has taken an approach to lease equipment and services that allow for exiting the project.

In North America, a positive supply of natural gas continues through technology improvements in directional drilling and is forecast to include an abundant supply of LNG beyond 2020. Please refer to the following:

http://www.gov.bc.ca/ener/popt/down/liquefied_natural_gas_strategy.pdf

Yukon Electrical is securing the services of ATCO Gas for their expertise in providing natural gas to over 1,000,000 customers for their provision of a bundled solution of equipment and services to provide natural gas for the project.

Yukon Electrical is participating in the YESAB process and does not foresee a high level of risk related to obtaining necessary approvals. An unknown at this time is the cost of emissions monitoring required to meet Yukon Territorial Government requirements. Yukon Electrical sees this risk as moderate due to the extensive acceptance of natural gas in other jurisdictions.

The risk of not proceeding with the chosen alternative is that objectives of communities for reducing emissions from diesel generating sources are not advanced while longer term solution technologies such as hydro, wind and geothermal are being advanced. One of the significant challenges of other technology options is their higher cost of electricity and/or time to get to market. LNG provides the capability to meet power capacity requirements in place of only straight energy displacement of other technologies such as wind and solar. LNG has been identified as having the potential to generate lower cost power with lower overall emissions.

This project advances Yukon Electrical's on-going commitment to meet the growing energy requirements of the Yukon. This project also advances a strategic objective to provide the lowest cost electrical production possible to the residents of the Yukon, in an environmentally sound manner possible. The Watson Lake project will allow Yukon Electrical to continue it's commitment to these objectives.

(b) For details of capital costs, operating costs and cash flow related to the Watson Lake Bi-Fuel project please refer to YUB-YECL-42(a).

(c) Yukon Electrical has a high degree of confidence in the capital costs related to this project with the exception of emissions testing. Engineering study and design for the project is complete. Equipment costs are known and installation and construction costs have been forecast. A competitive tendering process for installation/construction will commence in late summer 2013. However, the cost for emissions testing related to the requirements of the Yukon Territorial Government has not yet been fully evaluated.

UCG-YECL-105

Reference: May 27, 2013 Application, Business Case #7

Fish Lake Dyke Upgrade

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #7 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-106

Reference: May 27, 2013 Application, Business Case #8

Old Crow Plant Expansion

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #8 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-107

Reference: May 27, 2013 Application, Business Case #9

Fish Lake Ditch #3 Diversion Structure Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #9 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-108

Reference: May 27, 2013 Application, Business Case #10

Old Crow Unit # 4 Addition

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #10 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-109

Reference: May 27, 2013 Application, Business Case #11

Beaver Creek Unit # 1 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #11 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-110

Reference: May 27, 2013 Application, Business Case #12

Carcross 2 MVA Standby Project

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #12 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-111

Reference: May 27, 2013 Application, Business Case #13

Watson Lake Unit #2 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #13 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-112

Reference: May 27, 2013 Application, Business Case #14

Destruction Bay Unit #2 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #14 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-113

Reference: May 27, 2013 Application, Business Case #15

Old Crow Unit #3 Replacement

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #15 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-114

Reference: May 27, 2013 Application, Business Case #16

Whistle Bend Subdivision Stage 1 & 2

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #16 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project. Please include costs being incurred by YEC to service this subdivision.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) This project was completed in 2012.

UCG-YECL-115

Reference: May 27, 2013 Application, Business Case #17

Whistle Bend Subdivision Stage 3

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #17 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-116

Reference: May 27, 2013 Application, Business Case #18

Hillcrest Subdivision Conversion

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #18 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-117

Reference: May 27, 2013 Application, Business Case #19

Whistle Bend 34.5kV Substation Distribution Lines

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #19 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) This project was completed in 2011.

UCG-YECL-118

Reference: May 27, 2013 Application, Business Case #20

Whistle Bend Substation

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #20 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) This project was completed in 2012.

UCG-YECL-119

Reference: May 27, 2013 Application, Business Case #21

Crestview to Mayo Road Corner Double Circuit

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #21 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) This project was completed in 2012.

UCG-YECL-120

Reference: May 27, 2013 Application, Business Case #22

McIntyre Subdivision Replacement Stage 1

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #22 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-121

Reference: May 27, 2013 Application, Business Case #23

Whitehorse 5L628 and New 35kV Build

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #23 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-122

Reference: May 27, 2013 Application, Business Case #24

Downtown Whitehorse 25 kV Conversion

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #24 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-123

Reference: May 27, 2013 Application, Business Case #25

Takhini Marwell 4L315 Upgrade to 266 ACSR

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #25 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-124

Reference: May 27, 2013 Application, Business Case #26

Whistle Bend Stage 1, 2 & 3 Street Lights

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #26 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-125

Reference: May 27, 2013 Application, Business Case #27 - AMR

YUB Decision 2009-2, Appendix A, Direction No. 23

"*The Board encourages YECL to work with all Interveners, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Interveners, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA.*"

Request:

(a) Please identify where in the business case submitted YECL has addressed concerns raised by intervenors.

(b) Please provide details on how YECL worked with all intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Please provide all material provided at public and or stakeholder meetings and minutes of these meetings.

(c) Please provide specific details on the total cost of the AMR project – capital and operating.

(d) Will the proposed AMR meters make data available over unsecured wireless transmissions? What safeguards will be in place to guard against data intruders? Please provide any study that YECL has undertaken or used to address privacy and data security issues.

(e) Please provide YECL's analysis of the electromagnetic emissions expected from its AMR meters and the impact that will have on individuals.

(f) Please provide a copy of any investigation in YECL's possession as to whether the AMR meters proposed for the Yukon will pose any health hazard to Yukoners.

(g) Please identify the subject expert who conducted the economic analysis of the AMR project and will be available to address specific questions about the analysis that suggests that there is a cost savings of over $2 million over 25 years as compared to conventional meter reading.

(h) Please confirm that the AMR meters will remain more expensive for ratepayers for at least 8 years after installation versus the status quo.

(i) Please provide a comparison of the evaluation of the AMR meter project proposed by Newfoundland and Labrador Hydro for its Bear Cove and Plum Point service areas which indicates that there would be positive net present value after 10 years and total savings of $147,710 after 15 years. http://www.pub.nf.ca/applications/NLH2013Capital/files/application/NLH2013Application-VolumeII-Report23.pdf

(j) Please provide economic analysis conducted by utilities comparable to YECL related to proposed AMR metering projects and the related regulator decisions regarding their implementation.

(k) Please provide the Excel version of the economic analysis and ensure that all columns are sized to allow all numbers to be seen instead of "######".

(l) Please redo the economic analysis assuming a capital structure of 60% debt / 40% equity, an inflation factor of 1%

(m) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #27 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(n) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Please refer to YUB-YECL-48(b).

(b) Please refer to YUB-YECL-48(b), (c) and (k).

(c) Please refer to May 27, 2013 Application, Business Case #27 – AMR and the corresponding attachment – Attachment 1 for the total cost of the AMR project separated by capital and operating costs.

(d) Yukon Electrical's proposed AMR meters will transmit meter data over the current-bearing wires via Power Line Carriers, so there are no wireless transmissions. In ATCO Electric's 20 plus years of experience with this technology, there have been no data security issues.

(e) No radio communications are used to obtain readings from the meter-to-substation link. Readings are sent over the current-bearing wires. Yukon Electrical is not aware of any additional electromagnetic emissions risks caused by an upgrade from conventional meters to AMR meters.

(f) Yukon Electrical has not conducted any investigations for possible health hazards. However, ATCO Electric has never experienced any health hazards associated with AMR meters in its 20 plus years of using this technology. The AMR project will actually reduce health hazards associated with conventional meter reading, as no human meter reader will be exposed to hazards such as dog bites, customer premise hazards, extreme weather, high hazard mileage, etc.

(g) The economic analysis was prepared by Yukon Electrical staff. Yukon Electrical expects its panel members will be able to answer questions on the material files as part of this Application.

(h) Confirmed. Attachment 1 of Yukon Electrical's Business Case #27 (page 1 of 11) shows the cross-over of savings between AMR meters and No AMR occurring in year 9.

(i) Yukon Electrical has completed this comparison of the Newfoundland Labrador Hydro (NLH) business case. The AMR projects are similar in that they are both power line carrier based technology for AMR, both require existing meters to be exchanged with new AMR meters, and both require Substation Communication Equipment to be installed. The stated benefits of the projects are also similar:

reduced meter reading errors and estimates; enhanced safety through reducing employee risk exposure; and environmental benefits as a result of decreased vehicle usage. Please refer to UCG-YECL-125(i) Attachment 1 for an economic comparison of the two projects.

(j) As Yukon Electrical's proposed AMR project mirrors that implemented by Northland Utilities (Yellowknife) Limited ("NUY") in 2010, NUY is used as a comparable utility. Please refer to UCG-YECL-125(j) Attachment 1 (NUY's Economic Analysis) and UCG-YECL-125(j) Attachment 2 (NUYs AMR Business Case). Please also refer to UCG-YECL-125(j) Attachment 3 for the NWTPUB's decision regarding NUY's AMR project.

(a) Please refer to YUB-YECL-48(m) Attachment 1 for the Excel model.

(b) Please refer to UCG-YECL-125(l) Attachment 1 for the revised AMR economic analysis assuming a capital structure of 60% debt and 40% equity and an inflation rate of 1%. The savings over the life of the project in this scenario are $1.8M ($2.2M as presented in Business Case #27 in the Application). The cross-over point is in year 10 (year 9 in the model included in the Application).

(c) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61.

Yukon Electrical believes that it has provided sufficient information on this project to allow for the testing of this Application.

(d) Yukon Electrical continues to be confident in the forecast capital cost of this project.

The Yukon Electrical Company Limited
Comparison of AMR Projects

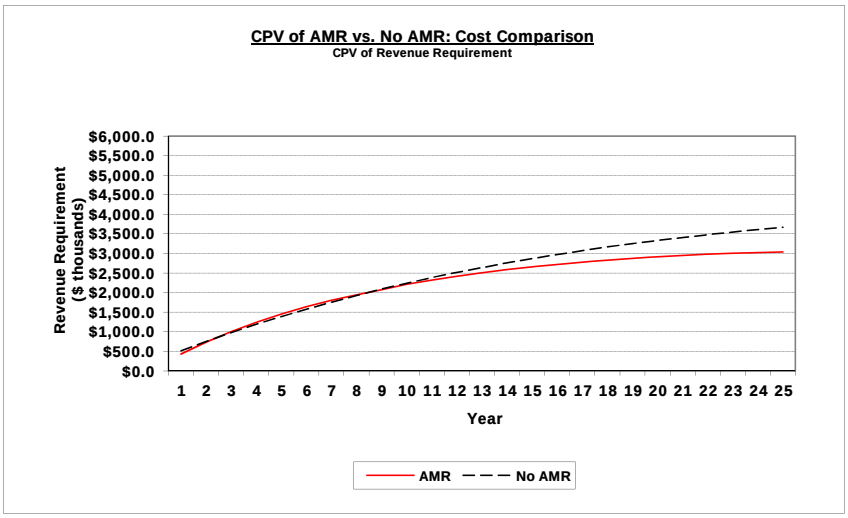
	Newfoundland and Labrador Hydro Bear Cove and Plum Point	The Yukon Electrical Company Limited Whitehorse and Area
Communities Included	2	5
Number of Meters to Convert	1,975	14,482
Budgeted Capital Cost ($000)	$656,700	$3,863,000
Cost Per Unit ($)	$332.51	$266.74
Cost Savings after 15 Years	$147,710	$835,100
Crossover Point	10 years	9 years

Cost Comparison: **Yellowknife AMR Project Rebuttal**
Updated for Tax Rate and CCA Impact

	AMR	No AMR
Revenue Requirement		
CPV @ Year 5 *(thousands)*	**$1,453.0**	**$1,386.7**
CPV @ Year 25 *(thousands)*	**$3,039.4**	**$3,667.2**

2010

Capital Cost Summary	**AMR**	**No AMR**
($000's)		
Generation Incremental		
Generation Existing		
Distribution	**$2,558.5**	**$0.0**
Transmission		
Total	**$2,558.5**	**$0.0**



Graph Data:

Societal

Year	AMR	No AMR
1	$426.2	$512.8
2	$733.1	$749.1
3	$1,003.9	$973.2
4	$1,242.6	$1,185.6
5	$1,453.0	$1,386.7
6	$1,638.4	$1,576.9
7	$1,801.6	$1,756.6
8	$1,945.4	$1,926.3
9	$2,074.1	$2,086.4
10	$2,207.5	$2,237.3
11	$2,317.7	$2,379.5
12	$2,416.3	$2,513.4
13	$2,504.6	$2,639.3
14	$2,583.5	$2,757.8
15	$2,654.1	$2,869.1
16	$2,722.4	$2,973.8
17	$2,778.8	$3,072.0
18	$2,829.4	$3,164.2
19	$2,874.5	$3,250.7
20	$2,914.9	$3,331.9
21	$2,949.0	$3,407.9
22	$2,979.3	$3,479.2
23	$3,002.0	$3,546.0
24	$3,021.4	$3,608.6
25	$3,039.4	$3,667.2

Assumptions: Yellowknife AMR Project Rebuttal
AMR Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	7.050%	52.50%	0.0370	0.0370
Preferred	0.000%	0.00%	0.0000	0.0000
Common	9.600%	47.50%	0.0647	0.0456
TOTALS			10.169%	8.26%

B Income Taxes 29.50%

C Depreciation Rates: 4.96%

D Long Term Escalation Ra 3.0%

E US Exchange Rate 1.05

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Total number of AMR Meters (178,314 AMR + 8000 Yellowknife) 186,314

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*

Input Starting Year: **Jan-10**

J METERS:		Unit Cost	Year 0 Jan-10	Year 1 Jan-11	Year 2 Jan-12	Year 3 Jan-13	Year 4 Jan-14	Year 5 Jan-15	Year 6 Jan-16	Year 7 Jan-17	Year 8 Jan-18	Year 9 Jan-19	Year 10 Jan-20	Year 11 Jan-21	Year 12 Jan-22	Year 13 Jan-23	Year 14 Jan-24	Year 15 Jan-25	Year 16 Jan-26	Year 17 Jan-27	Year 18 Jan-28	Year 19 Jan-29	Year 20 Jan-30	Year 21 Jan-31	Year 22 Jan-32	Year 23 Jan-33	Year 24 Jan-34	Year 25 Jan-35	Year 26 Jan-36
# of Residential Meters to be installed			6,965	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
# of Commercial Meters to be installed			1,134	0	0	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
# Spare Residential Meters	0%		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
# Spare Commerical Meters	0%		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 Cost of Residential AMR Module		$75.00 /meter	$522,375	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500	$7,500
2 Cost of Commercial Meter		$345.00 /meter	$391,230	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500	$34,500
3 Cost of Commercial AMR Module		$200.00 /meter	$226,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
4 Retrofitting Costs		$15.00 /meter	$121,485	$0	$0	$0	$0	$0	$0	$0	$0	$0	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750	$750
5 Installation - Residential Meters and Module		$16.50 /meter	$114,923	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650	$1,650
6 Installation - Commercial Meters and Module		$55.00 /meter	$62,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750
		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		-$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		-$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Meter Read Verification	5%	$36.00 /hr	$14,578	$0	$0	$0	$0	$0	$0	$0	$0	$0	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270
8 Test Set & Spares Equipment			$18,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Contingency	10%		$147,176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742	$5,742
10 Project Management	5%		$73,588	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871	$2,871
Subtotal			$1,692,525	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033
K SUBSTATIONS:																													
# of Substations requirec *(costs for Two MUTs per Line)*			3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Design		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Structural Design		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Major Apparatus Engineering		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Technical & Business Support		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Construction Labour & Expenses		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Commissioning		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Trouble Shooting		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Telecommunication - Engineering		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Telecommunication - Fiber Optic Materials		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
DCSI Equipment		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MTU		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electrical Materials		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Structural Materials		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Warehouse & Trucking		$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11 DCSI Materials		$41,000 /sub	$123,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12 Installation & Materials		*$210,000 /sub*	$630,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13 Contingency	10%		$75,300	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14 Project Management	5%		$37,650	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$865,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL Capital			**$2,558,475**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**	**$66,033**
L Allocated AMR O&M Costs:																													
15 O&M Acct#71212 - DCSI TNS Maintenance Support		$0.44 /meter	$0	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564	$3,564
16 O&M Acct#71214 - Annual Sample Verification Process		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17 O&M Acct#72107 - I-Tek User Fees (Email & Server Stora		$0.13 /meter	$0	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053	$1,053
18 O&M Acct#72109 - PCs & Monitors		$0.09 /meter	$0	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729	$729
19 O&M Acct#72118 - I-Tek Support for TNS Server		$0.68 /meter	$0	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507	$5,507
20 Labour Acct#71211 - AMR Meter Reading		$1.39 /meter	$0	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258	$11,258
21 Labour Acct#71214 - AMR Verification		$0.03 /meter	$0	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243	$243
22 Labour Acct#71215 - AMR Substation Troubleshoot & Su		$0.71 /meter	$0	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750	$5,750
23 Labour Acct # 71250 - AMR Special Meter Reading		$0.23 /meter	$0	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863	$1,863
24 Conventional Manual Meter Reading Costs During Deploy			$111,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25 Conventional Meter Testing During Deployment			$27,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,000	$0	$0	$0	$0	$0	$15,000	$0	$0	$0	$0	$0	$15,000	$0	$0	$0	$0	$0	$0
26 Customer Applications & Service Orders			$78,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
27 Data Cap Costs			$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$236,000	$39,966	$39,966	$39,966	$39,966	$39,966	$39,966	$39,966	$39,966	$39,966	$54,966	$39,966	$39,966	$39,966	$39,966	$39,966	$54,966	$39,966	$39,966	$39,966	$39,966	$39,966	$54,966	$39,966	$39,966	$39,966	$39,966	$39,966	$39,966

M **CCA Tax Savings**

If CCA > Depreciation, then Income Tax Savings = (CCA - Depreciation) x Tax Rate

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
Beg UCC		$2,558,475	######	######	######	######	$943,156	$754,525	$603,620	$482,896	$386,317	$368,483	$354,216	$342,803	$333,672	$326,367	$320,523	$315,848	$312,108	$309,116	$306,723	$304,808	$303,276	$302,051	$301,070	$300,286	$299,658
Capital Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033	$66,033
CAA	20%	$255,847	$460,525	$368,420	$294,736	$235,789	$188,631	$150,905	$120,724	$96,579	$83,867	$80,300	$77,447	$75,164	$73,338	$71,877	$70,708	$69,773	$69,025	$68,427	$67,948	$67,565	$67,259	$67,013	$66,817	$66,660	$66,535
End UCC		$2,302,627	######	######	######	$943,156	$754,525	$603,620	$482,896	$386,317	$368,483	$354,216	$342,803	$333,672	$326,367	$320,523	$315,848	$312,108	$309,116	$306,723	$304,808	$303,276	$302,051	$301,070	$300,286	$299,658	$299,156
CCA		$255,847	$460,525	$368,420	$294,736	$235,789	$188,631	$150,905	$120,724	$96,579	$83,867	$80,300	$77,447	$75,164	$73,338	$71,877	$70,708	$69,773	$69,025	$68,427	$67,948	$67,565	$67,259	$67,013	$66,817	$66,660	$66,535
Depreciation		$63,450	$126,900	$126,900	$126,900	$126,900	$126,900	$126,900	$126,900	$126,900	$126,900	$126,900	$129,101	$131,368	$133,703	$136,108	$138,585	$141,136	$143,764	$146,471	$149,259	$137,280	$107,839	$95,752	$83,644	$86,560	$89,678
CCA less Depreciation		$192,397	$333,625	$241,520	$167,836	$108,889	$61,731	$24,005	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allowable Inc Tax Savings / (Cost)	29.50%	$56,757	$98,419	$71,248	$49,512	$32,122	$18,211	$7,081	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
A Beg Bal (Savings)		$0	$32,348	$83,160	$109,223	$115,970	$107,749	$88,038	$59,619	$26,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
B Allowable Inc Tax Savings		$56,757	$98,419	$71,248	$49,512	$32,122	$18,211	$7,081	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
C Inc Tax Payable		$24,409	$47,607	$45,186	$42,764	$40,343	$37,922	$35,500	$33,079	$30,658	$28,236	$25,815	$24,240	$22,649	$21,040	$19,414	$17,770	$16,107	$14,425	$12,724	$11,001	$9,258	$7,776	$6,891	$6,271	$5,918	$5,547
Carry Fwd (savings)		$32,348	$83,160	$109,223	$115,970	$107,749	$88,038	$59,619	$26,540	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Inc Tax Payable		$24,409	$47,607	$45,186	$42,764	$40,343	$37,922	$35,500	$33,079	$30,658	$28,236	$25,815	$24,240	$22,649	$21,040	$19,414	$17,770	$16,107	$14,425	$12,724	$11,001	$9,258	$7,776	$6,891	$6,271	$5,918	$5,547
Actual Inc Tax Savings (Lesser of A+B or C)		**$24,409**	**$47,607**	**$45,186**	**$42,764**	**$40,343**	**$37,922**	**$35,500**	**$33,079**	**$26,540**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Taxes Payable after savings		$0	$0	$0	$0	$0	$0	$0	$0	$4,117	$28,236	$25,815	$24,240	$22,649	$21,040	$19,414	$17,770	$16,107	$14,425	$12,724	$11,001	$9,258	$7,776	$6,891	$6,271	$5,918	$5,547

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36
$522,375	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,079	$10,382	$10,693	$11,014	$11,344	$11,685	$12,035	$12,396	$12,768	$13,151	$13,546	$13,952	$14,371	$14,802	$15,246	$15,703	$16,174
$391,230	$0	$0	$0	$0	$0	$0	$0	$0	$0	$46,365	$47,756	$49,189	$50,664	$52,184	$53,750	$55,362	$57,023	$58,734	$60,496	$62,311	$64,180	$66,106	$68,089	$70,131	$72,235	$74,402
$226,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,439	$13,842	$14,258	$14,685	$15,126	$15,580	$16,047	$16,528	$17,024	$17,535	$18,061	$18,603	$19,161	$19,736	$20,328	$20,938	$21,566
$121,485	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,008	$1,038	$1,069	$1,101	$1,134	$1,168	$1,204	$1,240	$1,277	$1,315	$1,355	$1,395	$1,437	$1,480	$1,525	$1,570	$1,617
$114,923	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,217	$2,284	$2,353	$2,423	$2,496	$2,571	$2,648	$2,727	$2,809	$2,893	$2,980	$3,069	$3,162	$3,256	$3,354	$3,455	$3,558
$62,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,696	$3,807	$3,921	$4,038	$4,160	$4,284	$4,413	$4,545	$4,682	$4,822	$4,967	$5,116	$5,269	$5,427	$5,590	$5,758	$5,931
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$14,578	$0	$0	$0	$0	$0	$0	$0	$0	$0	$363	$374	$385	$397	$408	$421	$433	$446	$460	$473	$488	$502	$517	$533	$549	$565	$582
$18,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$147,176	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,717	$7,948	$8,187	$8,432	$8,685	$8,946	$9,214	$9,491	$9,775	$10,069	$10,371	$10,682	$11,002	$11,332	$11,672	$12,022	$12,383
$73,588	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,858	$3,974	$4,093	$4,216	$4,343	$4,473	$4,607	$4,745	$4,888	$5,034	$5,185	$5,341	$5,501	$5,666	$5,836	$6,011	$6,192
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
######	$0	$0	$0	$0	$0	$0	$0	$0	$0	$88,743	$91,405	$94,147	$96,972	$99,881	$102,877	$105,964	$109,142	$112,417	$115,789	$119,263	$122,841	$126,526	$130,322	$134,231	$138,258	$142,406
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$123,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$630,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$75,300	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$37,650	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$865,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
######	$0	$0	$0	$0	$0	$0	$0	$0	$0	$88,743	$91,405	$94,147	$96,972	$99,881	$102,877	$105,964	$109,142	$112,417	$115,789	$119,263	$122,841	$126,526	$130,322	$134,231	$138,258	$142,406
$0	$3,670	$3,781	$3,894	$4,011	$4,131	$4,255	$4,383	$4,514	$4,650	$4,789	$4,933	$5,081	$5,233	$5,390	$5,552	$5,718	$5,890	$6,067	$6,249	$6,436	$6,629	$6,828	$7,033	$7,244	$7,461	$7,685
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$1,084	$1,117	$1,150	$1,185	$1,221	$1,257	$1,295	$1,334	$1,374	$1,415	$1,457	$1,501	$1,546	$1,593	$1,640	$1,690	$1,740	$1,792	$1,846	$1,902	$1,959	$2,017	$2,078	$2,140	$2,204	$2,271
$0	$751	$773	$796	$820	$845	$870	$896	$923	$951	$980	$1,009	$1,039	$1,070	$1,103	$1,136	$1,170	$1,205	$1,241	$1,278	$1,316	$1,356	$1,397	$1,439	$1,482	$1,526	$1,572
$0	$5,673	$5,843	$6,018	$6,199	$6,384	$6,576	$6,773	$6,977	$7,186	$7,401	$7,623	$7,852	$8,088	$8,330	$8,580	$8,838	$9,103	$9,376	$9,657	$9,947	$10,245	$10,553	$10,869	$11,195	$11,531	$11,877
$0	$11,595	$11,943	$12,301	$12,671	$13,051	$13,442	$13,845	$14,261	$14,689	$15,129	$15,583	$16,051	$16,532	$17,028	$17,539	$18,065	$18,607	$19,165	$19,740	$20,332	$20,942	$21,571	$22,218	$22,884	$23,571	$24,278
$0	$250	$258	$265	$273	$282	$290	$299	$308	$317	$327	$336	$346	$357	$368	$379	$390	$402	$414	$426	$439	$452	$466	$480	$494	$509	$524
$0	$5,923	$6,100	$6,283	$6,472	$6,666	$6,866	$7,072	$7,284	$7,503	$7,728	$7,960	$8,199	$8,444	$8,698	$8,959	$9,228	$9,504	$9,789	$10,083	$10,386	$10,697	$11,018	$11,349	$11,689	$12,040	$12,401
$0	$1,919	$1,976	$2,035	$2,097	$2,159	$2,224	$2,291	$2,360	$2,430	$2,503	$2,579	$2,656	$2,736	$2,818	$2,902	$2,989	$3,079	$3,171	$3,266	$3,364	$3,465	$3,569	$3,676	$3,787	$3,900	$4,017
$111,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$27,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,159	$0	$0	$0	$0	$0	$24,071	$0	$0	$0	$0	$0	$28,742	$0	$0	$0	$0
$78,000	$10,300	$10,609	$10,927	$11,255	$11,593	$11,941	$12,299	$12,668	$13,048	$13,439	$13,842	$14,258	$14,685	$15,126	$15,580	$16,047	$16,528	$17,024	$17,535	$18,061	$18,603	$19,161	$19,736	$20,328	$20,938	$21,566
$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$236,000	$30,865	$31,791	$32,745	$33,727	$34,739	$35,781	$36,855	$37,960	$39,099	$40,272	$41,480	$42,725	$44,007	$45,327	$46,687	$48,087	$49,530	$51,016	$52,546	$54,122	$55,746	$57,419	$59,141	$60,915	$62,743	$64,625

Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
$0	$2,635,229	$2,442,857	$2,012,914	$1,658,641	$1,366,721	$1,126,178	$927,970	$764,648	$630,070	$519,177	$510,067	$505,028	$503,417	$504,709	$508,469	$514,346	$522,049	$531,344	$542,038	$553,976	$567,033	$581,108	$596,123	$612,014	$628,732	$646,241
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$88,743	$91,405	$94,147	$96,972	$99,881	$102,877	$105,964	$109,142	$112,417	$115,789	$119,263	$122,841	$126,526	$130,322	$134,231	$138,258	$142,406
$0	$263,523	$488,571	$402,583	$331,728	$273,344	$225,236	$185,594	$152,930	$126,014	$112,710	$111,154	$110,420	$110,381	$110,930	$111,982	$113,466	$115,324	$117,510	$119,986	$122,721	$125,691	$128,874	$132,257	$135,826	$139,572	$143,489
$0	$2,371,706	$1,954,286	$1,610,332	$1,326,913	$1,093,376	$900,942	$742,376	$611,718	$504,056	$495,210	$490,318	$488,755	$490,008	$493,660	$499,365	$506,844	$515,868	$526,250	$537,840	$550,517	$564,183	$578,760	$594,188	$610,419	$627,418	$645,158
$0	$263,523	$488,571	$402,583	$331,728	$273,344	$225,236	$185,594	$152,930	$126,014	$112,710	$111,154	$110,420	$110,381	$110,930	$111,982	$113,466	$115,324	$117,510	$119,986	$122,721	$125,691	$128,874	$132,257	$135,826	$139,572	$143,489
$0	$65,354	$134,629	$138,667	$142,827	$147,112	$151,526	$156,071	$160,754	$165,576	$170,543	$175,660	$184,067	$192,918	$202,238	$212,051	$222,388	$233,277	$244,749	$256,837	$269,578	$255,381	$206,631	$188,975	$170,032	$181,238	$193,399
$0	$198,169	$353,943	$263,915	$188,901	$126,232	$73,710	$29,523	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$58,460	$104,413	$77,855	$55,726	$37,238	$21,744	$8,709	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$34,318	$90,872	$122,932	$134,441	$128,658	$108,276	$75,524	$34,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$58,460	$104,413	$77,855	$55,726	$37,238	$21,744	$8,709	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$25,141	$50,506	$49,376	$48,132	$46,769	$45,281	$43,661	$41,903	$40,001	$37,947	$35,734	$34,561	$33,261	$31,826	$30,247	$28,516	$26,623	$24,558	$22,311	$19,869	$17,222	$14,900	$13,599	$12,747	$12,391	$11,963
$0	$33,319	$88,225	$119,351	$130,525	$124,911	$105,122	$73,324	$33,620	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$25,141	$50,506	$49,376	$48,132	$46,769	$45,281	$43,661	$41,903	$40,001	$37,947	$35,734	$34,561	$33,261	$31,826	$30,247	$28,516	$26,623	$24,558	$22,311	$19,869	$17,222	$14,900	$13,599	$12,747	$12,391	$11,963
$0	$25,141	$50,506	$49,376	$48,132	$46,769	$45,281	$43,661	$41,903	$34,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,372	$37,947	$35,734	$34,561	$33,261	$31,826	$30,247	$28,516	$26,623	$24,558	$22,311	$19,869	$17,222	$14,900	$13,599	$12,747	$12,391	$11,963

Assumptions: Yellowknife AMR Project Rebuttal
Conventional Meter Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	7.050%	52.500%	0.0370	0.0370
Preferred	0.000%	0.000%	0.0000	0.0000
Common	9.600%	47.500%	0.0647	0.0456
TOTALS			10.169%	8.261%

B Income Taxes 29.50%

C Depreciation Rates: 4.96%

D Long Term Escalation Rat 3.0%

E US Exchange Rate 1.05

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Incremental Capital Cost:

Input Starting Construction Year		Jan-10																												
		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
	Unit Cost	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38
# of Residential Meters to be installed/replaced		240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
# of Commercial Meters to be installed/replaced		60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
1 Cost of Residential Meter	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2 Cost of Commercial Meter	$345.00 /meter	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700	$20,700
3 Installation - Residential Meters	$16.50 /meter	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960	$3,960
4 Installation - Commerical Meters	$55.00 /meter	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300	$3,300
5 Freight and Customs Cost (in CDN)	$5.00 /meter	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460	$29,460
SUBSTATIONS:																														
# of Substations required *(costs for Two Bus Sub)*		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 Electrical Design	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2 Structural Design	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Major Apparatus Engineering	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Technical & Business Support	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5 Construction Labour & Expenses	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Commissioning	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Trouble Shooting	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Telecommunication - Engineering	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Telecommunication - Fiber Optic Materials	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10 DCSI Equipment	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11 MTU	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12 Electrical Materials	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13 Structural Materials	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14 Warehouse & Trucking	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	$0, /sub	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		*$0*	*$0*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL Capital		**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**	**$29,460**

I **Conventional O&M Costs:**

1 Manual Meter Reading Costs		$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000	$111,000
2 Meter Test Costs		$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000	$55,000
3 Customer Applications & Service Orders		$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000	$78,000
4 Data Cap Costs		$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8																														
9																														
Subtotal		$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000
-																														
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$4
TOTAL O&M		**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,000**	**$264,002**	**$264,004**
Total Cash Flow		**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,460**	**$293,462**	**$293,464**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$20,700	$21,321	$21,961	$22,619	$23,298	$23,997	$24,717	$25,458	$26,222	$27,009	$27,819	$28,654	$29,513	$30,399	$31,311	$32,250	$33,217	$34,214	$35,240	$36,298	$37,387	$38,508	$39,663	$40,853	$42,079	$43,341	$44,641	$45,981	$47,360
$3,960	$4,079	$4,201	$4,327	$4,457	$4,591	$4,728	$4,870	$5,016	$5,167	$5,322	$5,482	$5,646	$5,815	$5,990	$6,170	$6,355	$6,545	$6,742	$6,944	$7,152	$7,367	$7,588	$7,815	$8,050	$8,291	$8,540	$8,796	$9,060
$3,300	$3,399	$3,501	$3,606	$3,714	$3,826	$3,940	$4,059	$4,180	$4,306	$4,435	$4,568	$4,705	$4,846	$4,992	$5,141	$5,296	$5,454	$5,618	$5,787	$5,960	$6,139	$6,323	$6,513	$6,708	$6,909	$7,117	$7,330	$7,550
$1,500	$1,545	$1,591	$1,639	$1,688	$1,739	$1,791	$1,845	$1,900	$1,957	$2,016	$2,076	$2,139	$2,203	$2,269	$2,337	$2,407	$2,479	$2,554	$2,630	$2,709	$2,790	$2,874	$2,960	$3,049	$3,141	$3,235	$3,332	$3,432
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$29,460	$30,344	$31,254	$32,192	$33,157	$34,152	$35,177	$36,232	$37,319	$38,439	$39,592	$40,780	$42,003	$43,263	$44,561	$45,898	$47,275	$48,693	$50,154	$51,658	$53,208	$54,804	$56,448	$58,142	$59,886	$61,683	$63,533	$65,439	$67,402
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$29,460	$30,344	$31,254	$32,192	$33,157	$34,152	$35,177	$36,232	$37,319	$38,439	$39,592	$40,780	$42,003	$43,263	$44,561	$45,898	$47,275	$48,693	$50,154	$51,658	$53,208	$54,804	$56,448	$58,142	$59,886	$61,683	$63,533	$65,439	$67,402
$111,000	$114,330	$117,760	$121,293	$124,931	$128,679	$132,540	$136,516	$140,611	$144,830	$149,175	$153,650	$158,259	$163,007	$167,897	$172,934	$178,122	$183,466	$188,970	$194,639	$200,478	$206,493	$212,687	$219,068	$225,640	$232,409	$239,382	$246,563	$253,960
$55,000	$56,650	$58,350	$60,100	$61,903	$63,760	$65,673	$67,643	$69,672	$71,763	$73,915	$76,133	$78,417	$80,769	$83,192	$85,688	$88,259	$90,907	$93,634	$96,443	$99,336	$102,316	$105,386	$108,547	$111,804	$115,158	$118,613	$122,171	$125,836
$78,000	$80,340	$82,750	$85,233	$87,790	$90,423	$93,136	$95,930	$98,808	$101,772	$104,825	$107,970	$111,209	$114,546	$117,982	$121,521	$125,167	$128,922	$132,790	$136,773	$140,877	$145,103	$149,456	$153,940	$158,558	$163,315	$168,214	$173,261	$178,458
$20,000	$20,600	$21,218	$21,855	$22,510	$23,185	$23,881	$24,597	$25,335	$26,095	$26,878	$27,685	$28,515	$29,371	$30,252	$31,159	$32,094	$33,057	$34,049	$35,070	$36,122	$37,206	$38,322	$39,472	$40,656	$41,876	$43,132	$44,426	$45,759
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$264,000	$271,920	$280,078	$288,480	$297,134	$306,048	$315,230	$324,687	$334,427	$344,460	$354,794	$365,438	$376,401	$387,693	$399,324	$411,303	$423,642	$436,352	$449,442	$462,926	$476,813	$491,118	$505,851	$521,027	$536,658	$552,757	$569,340	$586,420	$604,013
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$5
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$5
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4	$9
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$264,000	$271,920	$280,078	$288,480	$297,134	$306,048	$315,230	$324,687	$334,427	$344,460	$354,794	$365,438	$376,401	$387,693	$399,324	$411,303	$423,642	$436,352	$449,442	$462,926	$476,813	$491,118	$505,851	$521,027	$536,658	$552,757	$569,340	$586,425	$604,022
$293,460	$302,264	$311,332	$320,672	$330,292	$340,201	$350,407	$360,919	$371,746	$382,899	$394,386	$406,217	$418,404	$430,956	$443,885	$457,201	$470,917	$485,045	$499,596	$514,584	$530,021	$545,922	$562,300	$579,169	$596,544	$614,440	$632,873	$651,864	$671,424

Yellowknife AMR Project Rebuttal
AMR Cost Impact

2013-08-29

Year	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
1 Cost of Residential AMR Module	261,188	261,188	0	0	0	0	0	0	0	0	0	5,040	5,191	5,347	5,507	5,672	5,842	6,018	6,198	6,384	6,576	6,773	6,976	7,185	7,401	7,623	7,852	8,087
2 Cost of Commercial Meter	195,615	195,615	0	0	0	0	0	0	0	0	0	23,183	23,878	24,594	25,332	26,092	26,875	27,681	28,512	29,367	30,248	31,155	32,090	33,053	34,044	35,066	36,118	37,201
3 Cost of Commercial AMR Module	113,400	113,400	0	0	0	0	0	0	0	0	0	6,720	6,921	7,129	7,343	7,563	7,790	8,024	8,264	8,512	8,768	9,031	9,301	9,581	9,868	10,164	10,469	10,783
4 Retrofitting Costs	60,743	60,743	0	0	0	0	0	0	0	0	0	504	519	535	551	567	584	602	620	638	658	677	698	719	740	762	785	809
5 Installation - Residential Meters and Module	57,461	57,461	0	0	0	0	0	0	0	0	0	1,109	1,142	1,176	1,212	1,248	1,285	1,324	1,364	1,405	1,447	1,490	1,535	1,581	1,628	1,677	1,727	1,779
6 Installation - Commercial Meters and Modul	31,185	31,185	0	0	0	0	0	0	0	0	0	1,848	1,903	1,960	2,019	2,080	2,142	2,206	2,273	2,341	2,411	2,483	2,558	2,635	2,714	2,795	2,879	2,965
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Meter Read Verification	7,289	7,289	0	0	0	0	0	0	0	0	0	181	187	192	198	204	210	217	223	230	237	244	251	259	266	274	283	291
8 Test Set & Spares Equipment	9,000	9,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Contingency	73,588	73,588	0	0	0	0	0	0	0	0	0	3,858	3,974	4,093	4,216	4,343	4,473	4,607	4,745	4,888	5,034	5,185	5,341	5,501	5,666	5,836	6,011	6,192
10 Project Management	36,794	36,794	0	0	0	0	0	0	0	0	0	1,929	1,987	2,047	2,108	2,171	2,236	2,304	2,373	2,444	2,517	2,593	2,670	2,751	2,833	2,918	3,006	3,096
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Design	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Structural Design	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Major Apparatus Engineering	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Technical & Business Support	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Construction Labour & Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commissioning	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trouble Shooting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Telecommunication - Engineering	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Telecommunication - Fiber Optic Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DCSI Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MTU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Structural Materials	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Warehouse & Trucking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 DCSI Materials	61,500	61,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Installation & Materials	315,000	315,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Contingency	37,650	37,650	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Project Management	18,825	18,825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	1,279,237	1,279,237	0	0	0	0	0	0	0	0	0	44,371	45,703	47,074	48,486	49,940	51,439	52,982	54,571	56,208	57,895	59,631	61,420	63,263	65,161	67,116	69,129	71,203

Operations & Maintenance:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Allocated AMR O&M Costs:																												
15 O&M Acct#71212 - DCSI TNS Maintenance	0	3,670	3,781	3,894	4,011	4,131	4,255	4,383	4,514	4,650	4,789	4,933	5,081	5,233	5,390	5,552	5,718	5,890	6,067	6,249	6,436	6,629	6,828	7,033	7,244	7,461	7,685	0
16 O&M Acct#71214 - Annual Sample Verificat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 O&M Acct#72107 - I-Tek User Fees (Email &	0	1,084	1,117	1,150	1,185	1,221	1,257	1,295	1,334	1,374	1,415	1,457	1,501	1,546	1,593	1,640	1,690	1,740	1,792	1,846	1,902	1,959	2,017	2,078	2,140	2,204	2,271	0
18 O&M Acct#72109 - PCs & Monitors	0	751	773	796	820	845	870	896	923	951	980	1,009	1,039	1,070	1,103	1,136	1,170	1,205	1,241	1,278	1,316	1,356	1,397	1,439	1,482	1,526	1,572	0
19 O&M Acct#72118 - I-Tek Support for TNS S	0	5,673	5,843	6,018	6,199	6,384	6,576	6,773	6,977	7,186	7,401	7,623	7,852	8,088	8,330	8,580	8,838	9,103	9,376	9,657	9,947	10,245	10,553	10,869	11,195	11,531	11,877	0
20 Labour Acct#71211 - AMR Meter Reading	0	11,595	11,943	12,301	12,671	13,051	13,442	13,845	14,261	14,689	15,129	15,583	16,051	16,532	17,028	17,539	18,065	18,607	19,165	19,740	20,332	20,942	21,571	22,218	22,884	23,571	24,278	0
21 Labour Acct#71214 - AMR Verification	0	250	258	265	273	282	290	299	308	317	327	336	346	357	368	379	390	402	414	426	439	452	466	480	494	509	524	0
22 Labour Acct#71215 - AMR Substation Troub	0	5,923	6,100	6,283	6,472	6,666	6,866	7,072	7,284	7,503	7,728	7,960	8,199	8,444	8,698	8,959	9,228	9,504	9,789	10,083	10,386	10,697	11,018	11,349	11,689	12,040	12,401	0
23 Labour Acct# 71250 - AMR Special Meter Re	0	1,919	1,976	2,035	2,097	2,159	2,224	2,291	2,360	2,430	2,503	2,579	2,656	2,736	2,818	2,902	2,989	3,079	3,171	3,266	3,364	3,465	3,569	3,676	3,787	3,900	4,017	0
24 Conventional Manual Meter Reading Costs D	111,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27 Conventional Meter Testing During Deployn	27,000	0	0	0	0	0	0	0	0	0	20,159	0	0	0	0	0	24,071	0	0	0	0	0	28,742	0	0	0	0	0
28 Customer Applications & Service Orders	78,000	10,300	10,609	10,927	11,255	11,593	11,941	12,299	12,668	13,048	13,439	13,842	14,258	14,685	15,126	15,580	16,047	16,528	17,024	17,535	18,061	18,603	19,161	19,736	20,328	20,938	21,566	0
29 Data Cap Costs	20,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 CCA Tax Savings	0	-25,141	-50,506	-49,376	-48,132	-46,769	-45,281	-43,661	-41,903	-34,629	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	236,000	16,024	-8,106	-5,704	-3,149	-437	2,441	5,493	8,725	17,518	73,870	55,323	56,982	58,692	60,453	62,266	88,205	66,058	68,040	70,081	72,184	74,349	105,321	78,877	81,243	83,681	86,191	0

Yellowknife AMR Project Rebuttal

AMR Cost Impact

Year	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
Cost of Residential AMR Module	4.960%	12,955	25,910	25,910	25,910	25,910	25,910	25,910	25,910	25,910	25,910	25,910	26,160	26,417	26,682	26,956	27,237	27,527	27,825	28,133	28,449	28,775	29,111	18,919	7,196	7,412	7,634	7,863
Cost of Commercial Meter	4.960%	9,703	19,405	19,405	19,405	19,405	19,405	19,405	19,405	19,405	19,405	19,405	20,555	21,739	22,959	24,216	25,510	26,843	28,216	29,630	31,087	32,587	34,132	35,724	37,363	39,052	40,791	42,582
Cost of Commercial AMR Module	4.960%	5,625	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,249	11,583	11,926	12,279	12,644	13,019	13,405	13,803	14,213	14,635	15,070	15,518	15,979	16,455	16,944	17,448	17,967
Retrofitting Costs	4.960%	3,013	6,026	6,026	6,026	6,026	6,026	6,026	6,026	6,026	6,026	6,026	6,051	6,076	6,103	6,130	6,158	6,187	6,217	6,248	6,280	6,312	2,941	699	720	741	763	786
Installation - Residential Meters and Module	4.960%	2,850	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,755	5,812	5,870	5,930	5,992	6,056	6,122	6,189	6,259	6,331	6,404	4,162	1,583	1,631	1,679	1,730
Installation - Commercial Meters and Modul	4.960%	1,547	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,185	3,280	3,377	3,477	3,580	3,686	3,796	3,909	4,025	4,144	4,267	4,394	4,525	4,660	4,798	4,941
	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Yellowknife AMR Project Rebuttal
AMR Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	7.050%	53%	0.0370	0.0370
Preferred	0.000%	0%	0.0000	0.0000
Common	9.600%	48%	0.0647	0.0456
Tax Rate	29.500%		10.169%	8.261%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 10.169%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-10	0	0	0	0	236,000	236,000	0	(236,000)	(236,000)	0
1	Jan-11	1,279,237	105,681	63,450	24,409	16,024	209,564	0	(209,564)	(426,220)	1
2	Jan-12	2,495,025	206,120	126,900	47,607	(8,106)	372,522	0	(372,522)	(733,143)	2
3	Jan-13	2,368,124	195,637	126,900	45,186	(5,704)	362,019	0	(362,019)	(1,003,882)	3
4	Jan-14	2,241,224	185,153	126,900	42,764	(3,149)	351,669	0	(351,669)	(1,242,603)	4
5	Jan-15	2,114,324	174,670	126,900	40,343	(437)	341,476	0	(341,476)	(1,453,008)	5
6	Jan-16	1,987,423	164,186	126,900	37,922	2,441	331,449	0	(331,449)	(1,638,384)	6
7	Jan-17	1,860,523	153,702	126,900	35,500	5,493	321,596	0	(321,596)	(1,801,646)	7
8	Jan-18	1,733,623	143,219	126,900	33,079	8,725	311,923	0	(311,923)	(1,945,380)	8
9	Jan-19	1,606,722	132,735	126,900	30,658	17,518	307,811	0	(307,811)	(2,074,128)	9
10	Jan-20	1,479,822	122,252	126,900	28,236	73,870	351,259	0	(351,259)	(2,207,486)	10
11	Jan-21	1,352,921	111,768	126,900	25,815	55,323	319,806	0	(319,806)	(2,317,695)	11
12	Jan-22	1,270,393	104,950	129,101	24,240	56,982	315,274	0	(315,274)	(2,416,314)	12
13	Jan-23	1,186,994	98,061	131,368	22,649	58,692	310,769	0	(310,769)	(2,504,551)	13
14	Jan-24	1,102,700	91,097	133,703	21,040	60,453	306,293	0	(306,293)	(2,583,489)	14
15	Jan-25	1,017,483	84,057	136,108	19,414	62,266	301,845	0	(301,845)	(2,654,100)	15
16	Jan-26	931,315	76,938	138,585	17,770	88,205	321,498	0	(321,498)	(2,722,366)	16
17	Jan-27	844,169	69,739	141,136	16,107	66,058	293,041	0	(293,041)	(2,778,846)	17
18	Jan-28	756,015	62,456	143,764	14,425	68,040	288,686	0	(288,686)	(2,829,351)	18
19	Jan-29	666,822	55,088	146,471	12,724	70,081	284,363	0	(284,363)	(2,874,507)	19
20	Jan-30	576,559	47,631	149,259	11,001	72,184	280,075	0	(280,075)	(2,914,877)	20
21	Jan-31	485,195	40,083	137,280	9,258	74,349	260,970	0	(260,970)	(2,949,022)	21
22	Jan-32	407,547	33,668	107,839	7,776	105,321	254,605	0	(254,605)	(2,979,258)	22
23	Jan-33	361,128	29,834	95,752	6,891	78,877	211,353	0	(211,353)	(3,002,041)	23
24	Jan-34	328,639	27,150	83,644	6,271	81,243	198,308	0	(198,308)	(3,021,445)	24
25	Jan-35	310,156	25,623	86,560	5,918	83,681	201,782	0	(201,782)	(3,039,366)	25
26	Jan-36	290,711	24,016	89,678	5,547	86,191	205,432	0	(205,432)	(3,055,927)	26
27	Jan-37	270,162	22,319	92,889	5,155	0	120,363	0	(120,363)	(3,064,734)	27
28	Jan-38	248,476	20,527	90,437	4,741	0	115,705	0	(115,705)	(3,072,420)	28
29	Jan-39	158,039	13,056	47,912	3,016	0	63,984	0	(63,984)	(3,076,277)	29
30	Jan-40	110,127	9,098	44,428	2,101	0	55,627	0	(55,627)	(3,079,321)	30
31	Jan-41	65,700	5,428	44,428	1,254	0	51,109	0	(51,109)	(3,081,860)	31
32	Jan-42	21,272	1,757	21,271	406	0	23,435	0	(23,435)	(3,082,917)	32
33	Jan-43	1	0	0	0	0	0	0	(0)	(3,082,917)	33
34	Jan-44	1	0	0	0	0	0	0	(0)	(3,082,917)	34
35	Jan-45	1	0	0	0	0	0	0	(0)	(3,082,917)	35
36	Jan-46	1	0	0	0	0	0	0	(0)	(3,082,917)	36
37	Jan-47	1	0	0	0	0	0	0	(0)	(3,082,917)	37
38	Jan-48	1	0	0	0	0	0	0	(0)	(3,082,917)	38
39	Jan-49	1	0	0	0	0	0	0	(0)	(3,082,917)	39
40	Jan-50	1	0	0	0	0	0	0	(0)	(3,082,917)	40

Yellowknife AMR Project Rebuttal
Conventional Meter Cost Impact

2013-08-29

Year	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement	14,730	29,902	31,268	32,675	33,655	34,664	35,704	36,776	37,879	39,015	40,186	41,391	42,633	43,912	45,229	46,586	47,984	49,423	50,906	52,433	54,006	55,626	57,295	59,014	60,784	62,608	64,486	66,421
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	14,730	29,902	31,268	32,675	33,655	34,664	35,704	36,776	37,879	39,015	40,186	41,391	42,633	43,912	45,229	46,586	47,984	49,423	50,906	52,433	54,006	55,626	57,295	59,014	60,784	62,608	64,486	66,421
O&M:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Manual Meter Reading Costs	111,000	114,330	117,760	121,293	124,931	128,679	132,540	136,516	140,611	144,830	149,175	153,650	158,259	163,007	167,897	172,934	178,122	183,466	188,970	194,639	200,478	206,493	212,687	219,068	225,640	232,409	239,382	246,563
Meter Test Costs	55,000	56,650	58,350	60,100	61,903	63,760	65,673	67,643	69,672	71,763	73,915	76,133	78,417	80,769	83,192	85,688	88,259	90,907	93,634	96,443	99,336	102,316	105,386	108,547	111,804	115,158	118,613	122,171
Customer Applications & Service Ord	78,000	80,340	82,750	85,233	87,790	90,423	93,136	95,930	98,808	101,772	104,825	107,970	111,209	114,546	117,982	121,521	125,167	128,922	132,790	136,773	140,877	145,103	149,456	153,940	158,558	163,315	168,214	173,261
Data Cap Costs	20,000	20,600	21,218	21,855	22,510	23,185	23,881	24,597	25,335	26,095	26,878	27,685	28,515	29,371	30,252	31,159	32,094	33,057	34,049	35,070	36,122	37,206	38,322	39,472	40,656	41,876	43,132	44,426
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	264,000	271,920	280,078	288,480	297,134	306,048	315,230	324,687	334,427	344,460	354,794	365,438	376,401	387,693	399,324	411,303	423,642	436,352	449,442	462,926	476,813	491,118	505,851	521,027	536,658	552,757	569,340	586,420

Yellowknife AMR Project Rebuttal
Conventional Meter Cost Impact

Year	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement	4.960%	731	2,214	3,765	5,385	7,055	8,774	10,545	12,369	14,248	16,183	18,176	20,229	22,344	24,522	26,765	29,076	31,456	33,907	36,432	39,033	41,711	44,471	47,312	50,239	53,254	56,360	59,558
2)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	4.960%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		731	2,214	3,765	5,385	7,055	8,774	10,545	12,369	14,248	16,183	18,176	20,229	22,344	24,522	26,765	29,076	31,456	33,907	36,432	39,033	41,711	44,471	47,312	50,239	53,254	56,360	59,558

ACCUMULATED DEPRECIATION:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement	0	731	2,944	6,709	12,094	19,149	27,923	38,468	50,837	65,084	81,267	99,443	119,672	142,016	166,538	193,303	222,379	253,834	287,741	324,174	363,206	404,918	449,388	496,701	546,940	600,195	656,554	716,113
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PROPERTY IN SERVICE (beg yr)	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement	0	14,730	43,901	72,955	101,865	130,135	157,745	184,675	210,906	236,416	261,183	285,186	308,401	330,805	352,373	373,081	392,902	411,810	429,778	446,776	462,778	477,751	491,666	504,490	516,192	526,737	536,090	544,217
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	14,730	43,901	72,955	101,865	130,135	157,745	184,675	210,906	236,416	261,183	285,186	308,401	330,805	352,373	373,081	392,902	411,810	429,778	446,776	462,778	477,751	491,666	504,490	516,192	526,737	536,090	544,217

Yellowknife AMR Project Rebuttal

Conventional Meter Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	7.050%	53%	0.0370	0.0370
Preferred	0.000%	0%	0.0000	0.0000
Common	9.600%	48%	0.0647	0.0456
Tax Rate	29.500%		10.169%	8.261%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 10.169%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-10	0	0	0	0	264,000	264,000	0	(264,000)	(264,000)	0
1	Jan-11	14,730	1,217	731	281	271,920	274,149	0	(274,149)	(512,843)	1
2	Jan-12	43,901	3,627	2,214	838	280,078	286,756	0	(286,756)	(749,103)	2
3	Jan-13	72,955	6,027	3,765	1,392	288,480	299,664	0	(299,664)	(973,208)	3
4	Jan-14	101,865	8,415	5,385	1,944	297,134	312,879	0	(312,879)	(1,185,598)	4
5	Jan-15	130,135	10,751	7,055	2,483	306,048	326,337	0	(326,337)	(1,386,675)	5
6	Jan-16	157,745	13,032	8,774	3,010	315,230	340,045	0	(340,045)	(1,576,858)	6
7	Jan-17	184,675	15,256	10,545	3,524	324,687	354,012	0	(354,012)	(1,756,577)	7
8	Jan-18	210,906	17,423	12,369	4,024	334,427	368,244	0	(368,244)	(1,926,264)	8
9	Jan-19	236,416	19,531	14,248	4,511	344,460	382,750	0	(382,750)	(2,086,356)	9
10	Jan-20	261,183	21,577	16,183	4,984	354,794	397,537	0	(397,537)	(2,237,284)	10
11	Jan-21	285,186	23,560	18,176	5,442	365,438	412,615	0	(412,615)	(2,379,477)	11
12	Jan-22	308,401	25,478	20,229	5,885	376,401	427,992	0	(427,992)	(2,513,354)	12
13	Jan-23	330,805	27,329	22,344	6,312	387,693	443,677	0	(443,677)	(2,639,327)	13
14	Jan-24	352,373	29,110	24,522	6,724	399,324	459,679	0	(459,679)	(2,757,796)	14
15	Jan-25	373,081	30,821	26,765	7,119	411,303	476,008	0	(476,008)	(2,869,150)	15
16	Jan-26	392,902	32,459	29,076	7,497	423,642	492,674	0	(492,674)	(2,973,763)	16
17	Jan-27	411,810	34,021	31,456	7,858	436,352	509,686	0	(509,686)	(3,071,999)	17
18	Jan-28	429,778	35,505	33,907	8,201	449,442	527,055	0	(527,055)	(3,164,206)	18
19	Jan-29	446,776	36,909	36,432	8,525	462,926	544,792	0	(544,792)	(3,250,718)	19
20	Jan-30	462,778	38,231	39,033	8,830	476,813	562,908	0	(562,908)	(3,331,856)	20
21	Jan-31	477,751	39,468	41,711	9,116	491,118	581,413	0	(581,413)	(3,407,925)	21
22	Jan-32	491,666	40,618	44,471	9,381	505,851	600,321	0	(600,321)	(3,479,218)	22
23	Jan-33	504,490	41,677	47,312	9,626	521,027	619,643	0	(619,643)	(3,546,013)	23
24	Jan-34	516,192	42,644	50,239	9,849	536,658	639,390	0	(639,390)	(3,608,575)	24
25	Jan-35	526,737	43,515	53,254	10,051	552,757	659,577	0	(659,577)	(3,667,155)	25
26	Jan-36	536,090	44,288	56,360	10,229	569,340	680,217	0	(680,217)	(3,721,991)	26
27	Jan-37	544,217	44,959	59,558	10,384	586,420	701,322	0	(701,322)	(3,773,310)	27
28	Jan-38	551,079	45,526	62,853	10,515	604,013	722,907	0	(722,907)	(3,821,325)	28
29	Jan-39	521,928	43,118	64,524	9,959	0	117,601	0	(117,601)	(3,828,415)	29
30	Jan-40	457,404	37,787	64,524	8,728	0	111,039	0	(111,039)	(3,834,492)	30
31	Jan-41	392,879	32,457	64,524	7,496	0	104,478	0	(104,478)	(3,839,682)	31
32	Jan-42	328,355	27,126	64,524	6,265	0	97,916	0	(97,916)	(3,844,096)	32
33	Jan-43	263,831	21,796	64,524	5,034	0	91,354	0	(91,354)	(3,847,835)	33
34	Jan-44	199,306	16,465	64,524	3,803	0	84,792	0	(84,792)	(3,850,985)	34
35	Jan-45	134,782	11,135	64,524	2,572	0	78,231	0	(78,231)	(3,853,623)	35
36	Jan-46	70,258	5,804	64,524	1,341	0	71,669	0	(71,669)	(3,855,816)	36
37	Jan-47	5,733	474	5,733	109	0	6,316	0	(6,316)	(3,855,992)	37
38	Jan-48	0	0	0	0	0	0	0	(0)	(3,855,992)	38
39	Jan-49	0	0	0	0	0	0	0	(0)	(3,855,992)	39
40	Jan-50	0	0	0	0	0	0	0	(0)	(3,855,992)	40

Automated Meter Reading ("AMR")
Business Case
Northland Utilities Limited
Yellowknife

Automatic Meter Reading (AMR) Business Case
Northland Utilities Limited - Yellowknife

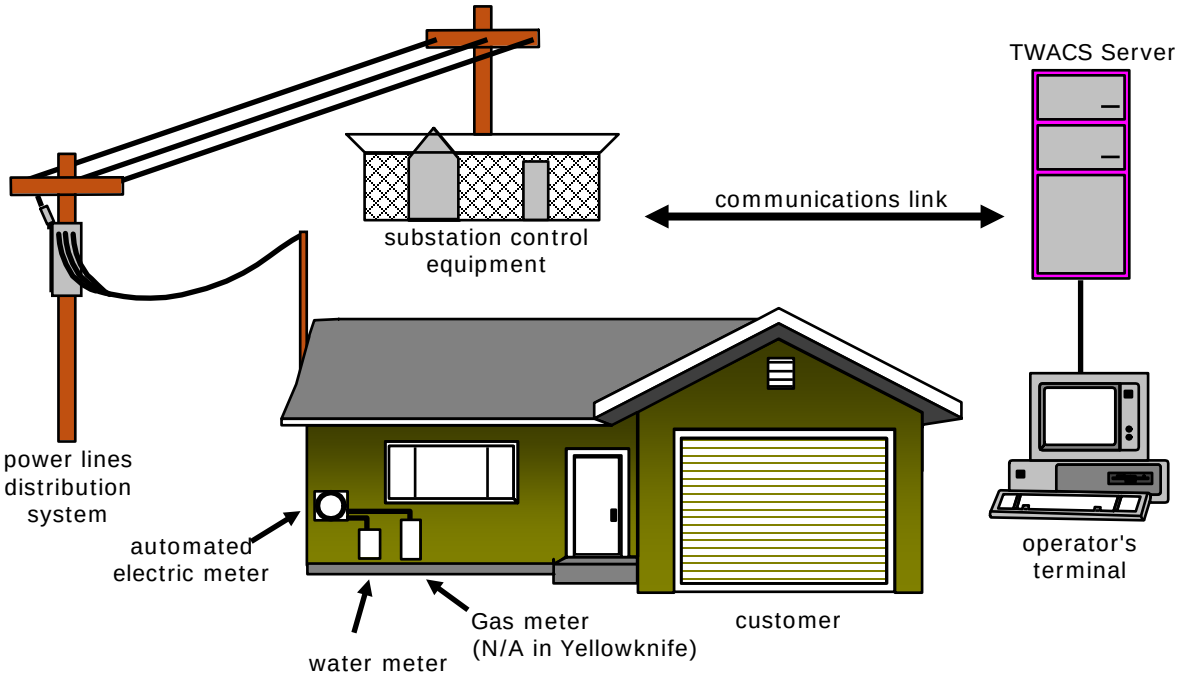
Summary

This project is to convert approximately 8,100 conventional residential and commercial meters to AMR. The benefits of the conversion will be improved customer service, long term savings over the life of the system, more environmentally friendly as well as the installation of metering technology that will support the eventual implementation of Time-of-Use rates.

Background

ATCO Electric has extensive experience in the implementation, operation and support of a system wide AMR system using a powerline frequency carrier technology known as "TWACS" (Two-Way Automatic Communication System) by Distribution Control Systems ("DCSI"). Although this business case is based on using this same technology as ATCO Electric, another powerline carrier AMR technology ("Turtle") was investigated. The choice of TWACS was mainly predicated on the fact that ATCO Electric has an established process and team in place to deal with its own AMR system and that there would be minimal incremental charges being incurred and allocated to Northland. Furthermore, given Northland's very small size and limited northern based technical resources, Northland was not prepared to go it alone with a different technology platform.

How TWACS AMR works



Project Description

The project consists of installing TWACS substation communication equipment ("SCE") in each of the three 25kV substations. Approximately 7,000 new residential modules as well as approximately 1,100 new commercial meters and modules will then be installed.

Project Cost

The cost of the project is estimated to be $ 2,558,500.

Project Schedule

This project is scheduled to be started and completed in 2010.

Business Drivers

- Accuracy - AMR results in increased customer service by being able to provide an accurate meter reading at any time and eliminates any access or privacy concerns;
- Savings - AMR is expected to result in long term customer savings;
- Access - AMR eliminates the need to access the meter on a regular basis thereby reducing the risk of animal bites to staff and customer complaints. AMR enables 24/7 access to meter readings;
- Customer Service and Planning - AMR provides voltage readings and momentary outages (blinks) at the AMR meters which can be used for engineering studies, operational requirements and customer conflicts;
- Operations - AMR technologies have advanced to include an Outage system, remote disconnect, re-connect systems that can enhance operations and service; and
- Technology Infrastructure - In conjunction with the new billing system, AMR moves Northland's metering and billing technologies forward towards being able to offer Time-of-Use rates.

Specific Benefits (All available once system is up and running by end of 2010)

- Improved accuracy of meter readings as chances of human error are eliminated;
- Reduction of billing inquiries or disputes from customers when readings are accurate;
- AMR meters are capable of hourly readings thereby providing to ability to produce load profiles and Time-of-Use rates;
- Reduction in manual re-estimations and cancellation/rebilling when readings are more accurate;
- Reduction in off-cycle meter reading requests when actual reads are missed or customer moves;
- Improved monitoring of meter performance such as stopped or failing meters;
- Improved customer service due to bills based on accurate monthly meter readings;
- Improved opportunity to utilize the AMR system, company wide, to perform value added distribution system O&M functions such as:
    - remote disconnect/reconnect
    - voltage readings at the meter
    - momentary outage counts (blinks) at the meter
    - outage assessment
- AMR system can be used to provide water AMR services to the City of Yellowknife. Northland has approached the City of Yellowknife regarding this opportunity on a number of occasions and has been advised they are studying their options.

Risk of Not Proceeding

- More meter reading errors than otherwise will take place;
- O&M costs will increase over time due to inflation;
- Load profiling would require some other technology; and
- No opportunity to implement Time-of-Use Rates

Risk of Proceeding

- Ensuring there are sufficient resources in place to implement the project in 2010.

Recommendation

- Proceed with deployment of TWACS AMR technology in 2010.

3.2.2 Automatic Meter Reading (AMR) Implementation and Conversion of Residential Mechanical Meters to Electronic Meters

NUL proposed that in 2010 it would convert its manual meter reading system to an Automatic Meter Reading ("**AMR**") system known as TWACS (Two-Way Automatic Communication System). NUL asserted that the project would improve customer service as well as provide long-term savings for customers and reduced environmental impact. NUL also noted that the project would move NUL's metering technology towards being able to process time-of-use rates. he projected cost of this project is $2.558 million in 2010.

For an additional cost of $0.483 million in 2010, NUL was also proposing to replace about 700 residential mechanical meters with electronic meters. While the meter conversion is necessary for the AMR project, NUL stated that the meter conversion project is economically justified on its own.

Yellowknife expressed concern about the Cumulative Present Value ("**CPV**") of the AMR project was only $0.165 million and that the economic cross-over did not occur for 20 years.

In rebuttal, NUL made corrections to its initial economic analysis and also provided some new information. NUL acknowledged that 1) the mechanical meters must be replaced with electronic meters for the AMR to function; and 2) there were no line loss savings associated with electronic meters per se although there were other benefits. For these reasons, Yellowknife asserted in its argument that the only meaningful CPV analysis is one that combines the capital and operating costs associated with both AMR and the conversion from mechanical to electronic meters.

At the hearing, NUL was requested by Yellowknife to provided additional CPV evaluations: 1) break-even; 2) 10% cost overrun; and 3) 20% cost overrun. As a result of these evaluations, Yellowknife remained concerned that the economics of this project were slim and that the potential exists for cost overruns to make the combined AMR/meter conversion project uneconomic. Yellowknife recommended that the Board should approve the combined AMR/meter conversion project subject to capital expenditure cap of $3.4 million to ensure that customers are no worse off after this project.

In its reply, NUL argues that the cost estimates it has provided are based on the best available information available to the company and that those estimates demonstrate that there will be a cost savings for the customer. With regards to a capital cost cap, NUL stated that it assumes the risk that it will have to justify any cost overruns so a capital cost cap is not required.

Views of the Board

The Board agrees with Yellowknife that the strong linkage between these two projects requires evaluating them in tandem rather than as separate stand-alone projects and so the Board has combined the two projects into this section of the decision.

The Board also agrees with Yellowknife that on the basis of a strict economic evaluation, the combined AMR/meter conversion project appears to produce benefits to the customers that could be eliminated by cost overruns that would not need to be that significant.

However, that Board is also of the view that the implementation of new and improved technology does not need to be completely justified by a strict

economic evaluation. The potential for future benefits, economic or otherwise and even if not yet fully identified and quantified, needs to be considered by the Board. As stated by NUL, additional functionalities such as remote disconnect capability, time-of-use metering and smart metering are add-ons to the basic AMR/meter conversion project that could produce future benefits but which have not been included in the current economic evaluation.

The Board agrees with NUL that it bears the risk of justifying any project cost overruns and any associated disallowance of costs by the Board. As a result, the Board does not see the need for a capital cost expenditure cap as recommended by Yellowknife.

The Board approves the AMR/meter conversion project as proposed by NUL for addition to the rate base in 2010.

3.3 Capital Deferral Account

NUL is proposing a Capital Deferral Account through to 2012 specifically for the 25 kV conversion project. In Section 7, NUL states:

> As noted in the testimony, the cost of capital evidence has been prepared based upon the assumption that the Board accepts Northland's continued request for a deferral account for capital additions relating to the 25 kV conversion. If the Board were to deny the continued use of this deferral account, the business risks faced by Northland would be significantly enhanced and would result in a significant increase in the fair rate of return, the common equity ratio or both.
>
> (GRA, Section 7, p. 7-2)

Yellowknife did not submit any comments regarding the Capital Deferral Account.

Cost Comparison: Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%

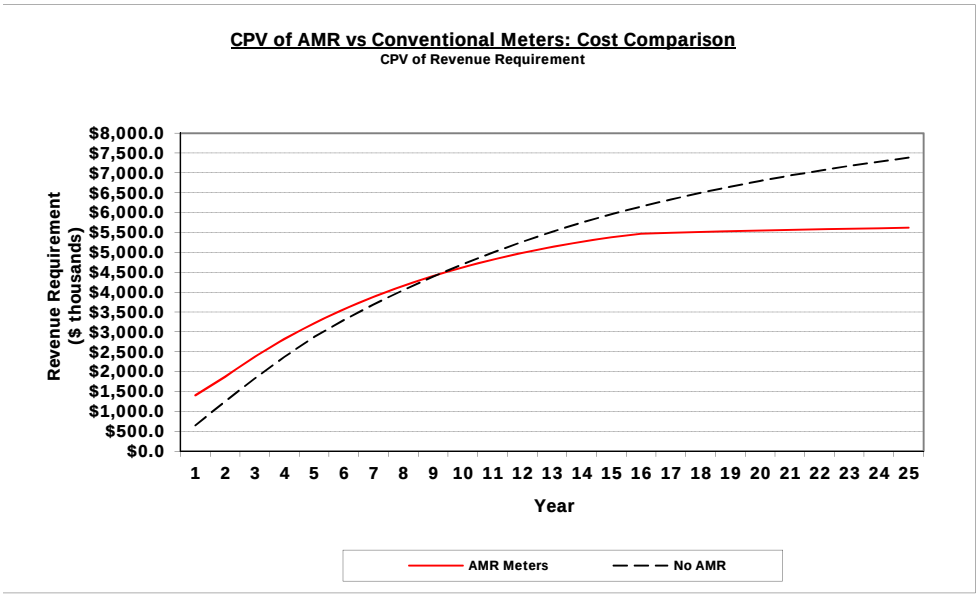
General Assumptions:
1. Analysis is over 25 years
2. AMR Implementation is over 2 years
3. Escalation Rate 2%
4. Analysis is on an incremental basis
5. Sunk capital costs are ignored
6. Future meter replacement costs are included

	AMR Meters	No AMR
Revenue Requirement		
CPV @ Year 5 *(thousands)*	**$3,213.7**	**$2,865.7**
CPV @ Year 25 *(thousands)*	**$5,620.3**	**$7,381.6**

2014/2015 Capital Cost Summary *(thousands)*	AMR Meters	No AMR
Generation Incremental		
Generation Existing		
Distribution	**$3,862.8**	**$307.1**
Transmission		
Total	**$3,862.8**	**$307.1**

Societal

Year	AMR Meters	No AMR
1	$1,401.2	$645.3
2	$1,871.4	$1,253.7
3	$2,370.9	$1,826.8
4	$2,816.6	$2,366.1
5	$3,213.7	$2,865.7
6	$3,567.1	$3,292.3
7	$3,881.3	$3,687.4
8	$4,160.1	$4,053.4
9	$4,407.2	$4,392.5
10	$4,625.8	$4,706.5
11	$4,818.9	$4,997.5
12	$4,988.9	$5,267.0
13	$5,138.4	$5,516.8
14	$5,269.5	$5,748.1
15	$5,379.3	$5,957.7
16	$5,465.0	$6,151.8
17	$5,492.5	$6,332.1
18	$5,512.9	$6,499.6
19	$5,531.8	$6,655.2
20	$5,549.4	$6,799.6
21	$5,565.8	$6,933.8
22	$5,580.9	$7,058.5
23	$5,595.0	$7,174.2
24	$5,608.1	$7,281.7
25	$5,620.3	$7,381.6



Assumptions: Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%
AMR Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**60.00%**	0.0348	0.03480
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**40.00%**	0.0526	0.03684
TOTALS		.	8.743%	7.164%

B Income Taxes **30.00%**

C Depreciation Rates: **7.13%**

D Escalation Rate **1.0%**

E US Exchange Rate **1.00**

F All analysis are based on 26 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Total number of AMR Meters **14,482 YECL** 192,796

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*

Input Starting Construction Year **Jan-14**

J **METERS:**		Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40
# of Residential Meters to be installed			6,343	6,560	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
# of Commercial Meters to be installed			0	1579	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
# Spare Residential Meters		0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
# Spare Commerical Meters		0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 Cost of Residential Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2 Cost of Residential AMR Module		$115.00 /meter	$729,445	$754,400	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225
3 Cost of Commercial Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4 Cost of Commercial AMR Module	=	$445.00 /meter	$0	$702,655	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540
5 Installation - Residential Meters		$16.50 /meter	$104,660	$108,240	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619
6 Installation - Commerical Meters		$205.00 /meter	$0	$323,695	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855
7 Freight		$10.00 /meter	$63,430	$81,390	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430
8 Billing System Configuration			$250,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10 Retrofitting Costs		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11 Meter Read Verification	5%	$36.00 /hr	$11,417	$14,650	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437
12 Test Set & Spares Equipment			$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13 Contingency	10%		$117,895	$198,503.02	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711
14 Project Management	5%		$58,947.60	$99,251.51	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$1,355,795	$2,282,785	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819
K **SUBSTATIONS:**																														
# of Substations required			2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials			$160,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16 Installation by YECL			$35,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17 Contingency	10%		$19,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18 Project Management	5%		$9,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$224,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL Capital			**$1,580,045**	**$2,282,785**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**
L **Allocated AMR O&M Costs:** *includes contingency of* *25%*																														
19 O&M Acct#71212 - DCSI TNS Maintenance Support		$0.44 /meter	$0	$2,791	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582
20 O&M Acct#71214 - Annual Sample Verification Process		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21 O&M Acct#72107 - I-Tek User Fees (Email & Server Storage		$0.13 /meter	$0	$823	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645
22 O&M Acct#72109 - PCs & Monitors		$0.09 /meter	$0	$600	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201
23 O&M Acct#72118 - I-Tek Support for TNS Server		$0.69 /meter	$0	$4,359	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719
24 Labour Acct#71211 - AMR Meter Reading		$1.57 /meter	$0	$9,952	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905
25 Labour Acct#71214 - AMR Verification		$0.03 /meter	$0	$206	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411
26 Labour Acct#71215 - AMR Substation Troubleshoot & Suppc		$0.71 /meter	$0	$4,504	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007
27 Labour Acct# 71250 - AMR Special Meter Reading		$0.25 /meter	$0	$1,563	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126
28 Conventional Meter Read Costs	100%	of existing costs	$689,400	$617,400	$76,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29 Affiliate Charges																														
Subtotal			$689,400	$642,197	$126,395	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595
M **AMR O&M Savings / Revenue:**																														
29 Project Management			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30 Data-Cap Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31 Reduced Read-to-Bill Lag			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32 Manual Meter Reading Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33 Meter Test Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34 Special Read Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36 Labour Installation of Meters			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL O&M			**$689,400**	**$642,197**	**$126,395**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**
Total Cash Flow			**$2,269,445**	**$2,924,982**	**$180,568**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$729,445	$754,400	$25,732	$25,990	$26,250	$26,512	$26,777	$27,045	$27,315	$27,589	$27,864	$28,143	$28,425	$28,709	$28,996	$29,286	$29,579	$29,875	$30,173	$30,475	$30,780	$31,088	$31,398	$31,712	$32,030	$32,350	$32,673
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$702,655	$10,752	$10,859	$10,968	$11,077	$11,188	$11,300	$11,413	$11,527	$11,643	$11,759	$11,877	$11,995	$12,115	$12,236	$12,359	$12,482	$12,607	$12,733	$12,861	$12,989	$13,119	$13,250	$13,383	$13,517	$13,652
$104,660	$108,240	$3,692	$3,729	$3,766	$3,804	$3,842	$3,880	$3,919	$3,958	$3,998	$4,038	$4,078	$4,119	$4,160	$4,202	$4,244	$4,286	$4,329	$4,372	$4,416	$4,460	$4,505	$4,550	$4,596	$4,641	$4,688
$0	$323,695	$4,953	$5,003	$5,053	$5,103	$5,154	$5,206	$5,258	$5,310	$5,363	$5,417	$5,471	$5,526	$5,581	$5,637	$5,693	$5,750	$5,808	$5,866	$5,925	$5,984	$6,044	$6,104	$6,165	$6,227	$6,289
$63,430	$81,390	$2,479	$2,504	$2,529	$2,554	$2,580	$2,606	$2,632	$2,658	$2,685	$2,711	$2,739	$2,766	$2,794	$2,822	$2,850	$2,878	$2,907	$2,936	$2,966	$2,995	$3,025	$3,055	$3,086	$3,117	$3,148
$250,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$11,417	$14,650	$446	$451	$455	$460	$464	$469	$474	$478	$483	$488	$493	$498	$503	$508	$513	$518	$523	$529	$534	$539	$545	$550	$555	$561	$567
$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$117,895	$198,503	$4,805	$4,854	$4,902	$4,951	$5,001	$5,051	$5,101	$5,152	$5,204	$5,256	$5,308	$5,361	$5,415	$5,469	$5,524	$5,579	$5,635	$5,691	$5,748	$5,806	$5,864	$5,922	$5,981	$6,041	$6,102
$58,948	$99,252	$2,403	$2,427	$2,451	$2,476	$2,500	$2,525	$2,551	$2,576	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,355,795	$2,282,785	$55,263	$55,815	$56,374	$56,937	$57,507	$58,082	$58,663	$59,249	$57,240	$57,812	$58,390	$58,974	$59,564	$60,160	$60,761	$61,369	$61,983	$62,602	$63,228	$63,861	$64,499	$65,144	$65,796	$66,454	$67,118
$160,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$35,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$19,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$9,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$224,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,580,045	$2,305,613	$55,263	$55,815	$56,374	$56,937	$57,507	$58,082	$58,663	$59,249	$57,240	$57,812	$58,390	$58,974	$59,564	$60,160	$60,761	$61,369	$61,983	$62,602	$63,228	$63,861	$64,499	$65,144	$65,796	$66,454	$67,118
$0	$2,819	$5,694	$5,751	$5,808	$5,867	$5,925	$5,984	$6,044	$6,105	$6,166	$6,227	$6,290	$6,353	$6,416	$6,480	$6,545	$6,611	$6,677	$6,743	$6,811	$6,879	$6,948	$7,017	$7,087	$7,158	$7,230
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$831	$1,678	$1,695	$1,712	$1,729	$1,746	$1,764	$1,781	$1,799	$1,817	$1,835	$1,854	$1,872	$1,891	$1,910	$1,929	$1,948	$1,968	$1,987	$2,007	$2,027	$2,048	$2,068	$2,089	$2,110	$2,131
$0	$606	$1,225	$1,237	$1,250	$1,262	$1,275	$1,287	$1,300	$1,313	$1,326	$1,340	$1,353	$1,367	$1,380	$1,394	$1,408	$1,422	$1,436	$1,451	$1,465	$1,480	$1,495	$1,510	$1,525	$1,540	$1,555
$0	$4,403	$8,894	$8,983	$9,073	$9,163	$9,255	$9,347	$9,441	$9,535	$9,631	$9,727	$9,824	$9,922	$10,022	$10,122	$10,223	$10,325	$10,429	$10,533	$10,638	$10,745	$10,852	$10,961	$11,070	$11,181	$11,293
$0	$10,052	$20,305	$20,508	$20,713	$20,920	$21,129	$21,340	$21,554	$21,769	$21,987	$22,207	$22,429	$22,653	$22,880	$23,109	$23,340	$23,573	$23,809	$24,047	$24,287	$24,530	$24,775	$25,023	$25,273	$25,526	$25,781
$0	$208	$420	$424	$428	$432	$437	$441	$445	$450	$454	$459	$463	$468	$473	$477	$482	$487	$492	$497	$502	$507	$512	$517	$522	$527	$533
$0	$4,549	$9,188	$9,280	$9,373	$9,467	$9,561	$9,657	$9,753	$9,851	$9,949	$10,049	$10,149	$10,251	$10,353	$10,457	$10,561	$10,667	$10,774	$10,882	$10,990	$11,100	$11,211	$11,323	$11,437	$11,551	$11,666
$0	$1,578	$3,188	$3,220	$3,252	$3,285	$3,318	$3,351	$3,384	$3,418	$3,453	$3,487	$3,522	$3,557	$3,593	$3,629	$3,665	$3,702	$3,739	$3,776	$3,814	$3,852	$3,890	$3,929	$3,969	$4,008	$4,048
$689,400	$623,574	$78,344	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$648,619	$128,935	$51,097	$51,608	$52,124	$52,646	$53,172	$53,704	$54,241	$54,783	$55,331	$55,884	$56,443	$57,008	$57,578	$58,154	$58,735	$59,322	$59,916	$60,515	$61,120	$61,731	$62,348	$62,972	$63,602	$64,238
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$648,619	$128,935	$51,097	$51,608	$52,124	$52,646	$53,172	$53,704	$54,241	$54,783	$55,331	$55,884	$56,443	$57,008	$57,578	$58,154	$58,735	$59,322	$59,916	$60,515	$61,120	$61,731	$62,348	$62,972	$63,602	$64,238
$2,269,445	$2,954,232	$184,198	$106,913	$107,982	$109,062	$110,152	$111,254	$112,366	$113,490	$112,023	$113,143	$114,275	$115,418	$116,572	$117,737	$118,915	$120,104	$121,305	$122,518	$123,743	$124,981	$126,230	$127,493	$128,768	$130,055	$131,356

Assumptions: Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%
Conventional Meter Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**60.00%**	0.0348	0.0348
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**40.00%**	0.0526	0.0368
TOTALS			8.743%	7.164%

B Income Taxes **30.00%**

C Depreciation Rates: **8.09%**

D Escalation Rate **1.0%**

E US Exchange Rate **1**

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Incremental Capital Cost:

Input Starting Construction Year: **Jan-14**

	Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40	Year 27 Jan-41	Year 28 Jan-42
# of Residential Meters to be installed/replaced		1,850	1,850	1,850	1,850	1,850	1,850	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
# of Commercial Meters to be installed/replaced		150	150	150	150	150	150	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
1 Cost of Residential Meter	$35.00 /meter	$64,750	$64,750	$64,750	$64,750	$64,750	$64,750	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000
2 Cost of Commercial Meter	#########	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
3 Installation - Residential Meters	$16.50 /meter	$30,525	$30,525	$30,525	$30,525	$30,525	$30,525	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600
4 Installation - Commerical Meters	$55.00 /meter	$8,250	$8,250	$8,250	$8,250	$8,250	$8,250	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750
5 Freight Cost (in CDN)	$10.00 /meter	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500
6 Residential Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Commerical Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Retrofitting Costs	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Meter Read Verification	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$153,525	$153,525	$153,525	$153,525	$153,525	$153,525	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850
TOTAL Capital		**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**

I **Conventional O&M Costs:**

1 Manual Meter Reading Costs		$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800
2 Meter Test Costs	$36.40 /meter	$72,800	$72,800	$72,800	$72,800	$72,800	$72,800	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380
3 Customer Applications & Service Orders		$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000
4 Data Cap Costs		$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8																														
9																														
TOTAL O&M		**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,982**	**$632,984**
Total Cash Flow		**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,832**	**$670,834**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41	Jan-42
$64,750	$65,398	$66,051	$66,712	$67,379	$68,053	$14,861	$15,010	$15,160	$15,312	$15,465	$15,619	$15,776	$15,933	$16,093	$16,254	$16,416	$16,580	$16,746	$16,914	$17,083	$17,253	$17,426	$17,600	$17,776	$17,954	$18,134	$18,315	$18,498
$30,000	$30,300	$30,603	$30,909	$31,218	$31,530	$10,615	$10,721	$10,829	$10,937	$11,046	$11,157	$11,268	$11,381	$11,495	$11,610	$11,726	$11,843	$11,961	$12,081	$12,202	$12,324	$12,447	$12,572	$12,697	$12,824	$12,953	$13,082	$13,213
$30,525	$30,830	$31,139	$31,450	$31,764	$32,082	$7,006	$7,076	$7,147	$7,218	$7,291	$7,363	$7,437	$7,511	$7,587	$7,662	$7,739	$7,816	$7,895	$7,974	$8,053	$8,134	$8,215	$8,297	$8,380	$8,464	$8,549	$8,634	$8,721
$8,250	$8,333	$8,416	$8,500	$8,585	$8,671	$2,919	$2,948	$2,978	$3,008	$3,038	$3,068	$3,099	$3,130	$3,161	$3,193	$3,225	$3,257	$3,289	$3,322	$3,356	$3,389	$3,423	$3,457	$3,492	$3,527	$3,562	$3,598	$3,634
$20,000	$20,200	$20,402	$20,606	$20,812	$21,020	$4,777	$4,825	$4,873	$4,922	$4,971	$5,021	$5,071	$5,121	$5,173	$5,224	$5,277	$5,329	$5,383	$5,436	$5,491	$5,546	$5,601	$5,657	$5,714	$5,771	$5,829	$5,887	$5,946
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$153,525	$155,060	$156,611	$158,177	$159,759	$161,356	$40,179	$40,580	$40,986	$41,396	$41,810	$42,228	$42,650	$43,077	$43,508	$43,943	$44,382	$44,826	$45,274	$45,727	$46,184	$46,646	$47,112	$47,584	$48,059	$48,540	$49,025	$49,516	$50,011
$153,525	$155,060	$156,611	$158,177	$159,759	$161,356	$40,179	$40,580	$40,986	$41,396	$41,810	$42,228	$42,650	$43,077	$43,508	$43,943	$44,382	$44,826	$45,274	$45,727	$46,184	$46,646	$47,112	$47,584	$48,059	$48,540	$49,025	$49,516	$50,011
$460,800	$465,408	$470,062	$474,763	$479,510	$484,305	$489,148	$494,040	$498,980	$503,970	$509,010	$514,100	$519,241	$524,433	$529,678	$534,974	$540,324	$545,727	$551,185	$556,697	$562,264	$567,886	$573,565	$579,301	$585,094	$590,945	$596,854	$602,823	$608,851
$72,800	$73,528	$74,263	$75,006	$75,756	$76,514	$17,388	$17,562	$17,737	$17,915	$18,094	$18,275	$18,457	$18,642	$18,828	$19,017	$19,207	$19,399	$19,593	$19,789	$19,987	$20,187	$20,388	$20,592	$20,798	$21,006	$21,216	$21,428	$21,643
$135,000	$136,350	$137,714	$139,091	$140,482	$141,886	$143,305	$144,738	$146,186	$147,648	$149,124	$150,615	$152,121	$153,643	$155,179	$156,731	$158,298	$159,881	$161,480	$163,095	$164,726	$166,373	$168,037	$169,717	$171,414	$173,128	$174,860	$176,608	$178,374
$20,800	$21,008	$21,218	$21,430	$21,645	$21,861	$22,080	$22,300	$22,523	$22,749	$22,976	$23,206	$23,438	$23,672	$23,909	$24,148	$24,390	$24,634	$24,880	$25,129	$25,380	$25,634	$25,890	$26,149	$26,410	$26,675	$26,941	$27,211	$27,483
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$696,294	$703,257	$710,290	$717,392	$724,566	$671,921	$678,640	$685,427	$692,281	$699,204	$706,196	$713,258	$720,390	$727,594	$734,870	$742,219	$749,641	$757,137	$764,709	$772,356	$780,079	$787,880	$795,759	$803,717	$811,754	$819,871	$828,073	$836,356
$842,925	$851,354	$859,868	$868,466	$877,151	$885,923	$712,100	$719,221	$726,413	$733,677	$741,014	$748,424	$755,908	$763,467	$771,102	$778,813	$786,601	$794,467	$802,412	$810,436	$818,540	$826,725	$834,993	$843,343	$851,776	$860,294	$868,897	$877,588	$886,367

Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%

AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
1 Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Cost of Residential AMR Module	364,723	741,923	377,200	12,866	12,995	13,125	13,256	13,389	13,523	13,658	13,794	13,932	14,072	14,212	14,354	14,498	14,643	14,789	14,937	15,087	15,237	15,390	15,544	15,699	15,856	16,015	16,175	16,337
3 Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Cost of Commercial AMR Module	0	351,328	351,328	5,376	5,430	5,484	5,539	5,594	5,650	5,707	5,764	5,821	5,879	5,938	5,998	6,058	6,118	6,179	6,241	6,304	6,367	6,430	6,495	6,560	6,625	6,691	6,758	6,826
5 Installation - Residential Meters	52,330	106,450	54,120	1,846	1,864	1,883	1,902	1,921	1,940	1,960	1,979	1,999	2,019	2,039	2,060	2,080	2,101	2,122	2,143	2,165	2,186	2,208	2,230	2,252	2,275	2,298	2,321	2,344
6 Installation - Commerical Meters	0	161,848	161,848	2,477	2,501	2,526	2,552	2,577	2,603	2,629	2,655	2,682	2,709	2,736	2,763	2,791	2,818	2,847	2,875	2,904	2,933	2,962	2,992	3,022	3,052	3,083	3,113	3,145
7 Freight	31,715	72,410	40,695	1,240	1,252	1,265	1,277	1,290	1,303	1,316	1,329	1,342	1,356	1,369	1,383	1,397	1,411	1,425	1,439	1,454	1,468	1,483	1,498	1,513	1,528	1,543	1,558	1,574
8 Billing System Configuration	125,000	125,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Meter Read Verification	5,709	13,034	7,325	223	225	228	230	232	235	237	239	242	244	246	249	251	254	256	259	262	264	267	270	272	275	278	281	283
12 Test Set & Spares Equipment	10,000	10,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Contingency	58,948	158,199	99,252	2,403	2,427	2,451	2,476	2,500	2,525	2,551	2,576	2,602	2,628	2,654	2,681	2,707	2,735	2,762	2,789	2,817	2,846	2,874	2,903	2,932	2,961	2,991	3,021	3,051
14 Project Management	29,474	79,100	49,626	1,201	1,213	1,226	1,238	1,250	1,263	1,275	1,288	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Aclara SCE materials	80,000	80,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16 Installation by YECL	17,500	17,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Contingency	9,750	9,750	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Project Management	4,875	4,875	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	790,022	1,931,415	1,141,392	27,631	27,908	28,187	28,469	28,753	29,041	29,331	29,625	28,620	28,906	29,195	29,487	29,782	30,080	30,381	30,684	30,991	31,301	31,614	31,930	32,250	32,572	32,898	33,227	33,559

Operations & Maintenance:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Allocated AMR O&M Costs:																												
19 O&M Acct#71212 - DCSI TNS Maintenanc	0	2,819	5,694	5,751	5,808	5,867	5,925	5,984	6,044	6,105	6,166	6,227	6,290	6,353	6,416	6,480	6,545	6,611	6,677	6,743	6,811	6,879	6,948	7,017	7,087	7,158	0	0
20 O&M Acct#71214 - Annual Sample Verifica	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 O&M Acct#72107 - I-Tek User Fees (Emai	0	831	1,678	1,695	1,712	1,729	1,746	1,764	1,781	1,799	1,817	1,835	1,854	1,872	1,891	1,910	1,929	1,948	1,968	1,987	2,007	2,027	2,048	2,068	2,089	2,110	0	0
22 O&M Acct#72109 - PCs & Monitors	0	606	1,225	1,237	1,250	1,262	1,275	1,287	1,300	1,313	1,326	1,340	1,353	1,367	1,380	1,394	1,408	1,422	1,436	1,451	1,465	1,480	1,495	1,510	1,525	1,540	0	0
23 O&M Acct#72118 - I-Tek Support for TNS	0	4,403	8,894	8,983	9,073	9,163	9,255	9,347	9,441	9,535	9,631	9,727	9,824	9,922	10,022	10,122	10,223	10,325	10,429	10,533	10,638	10,745	10,852	10,961	11,070	11,181	0	0
24 Labour Acct#71211 - AMR Meter Reading	0	10,052	20,305	20,508	20,713	20,920	21,129	21,340	21,554	21,769	21,987	22,207	22,429	22,653	22,880	23,109	23,340	23,573	23,809	24,047	24,287	24,530	24,775	25,023	25,273	25,526	0	0
25 Labour Acct#71214 - AMR Verification	0	208	420	424	428	432	437	441	445	450	454	459	463	468	473	477	482	487	492	497	502	507	512	517	522	527	0	0
26 Labour Acct#71215 - AMR Substation Trou	0	4,549	9,188	9,280	9,373	9,467	9,561	9,657	9,753	9,851	9,949	10,049	10,149	10,251	10,353	10,457	10,561	10,667	10,774	10,882	10,990	11,100	11,211	11,323	11,437	11,551	0	0
27 Labour Acct# 71250 - AMR Special Meter I	0	1,578	3,188	3,220	3,252	3,285	3,318	3,351	3,384	3,418	3,453	3,487	3,522	3,557	3,593	3,629	3,665	3,702	3,739	3,776	3,814	3,852	3,890	3,929	3,969	4,008	0	0
28 Conventional Meter Read Costs	689,400	623,574	78,344	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29 Affiliate Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AMR O&M Savings / Revenue:																												
29 Project Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30 Data-Cap Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31 Reduced Read-to-Bill Lag	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32 Manual Meter Reading Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	689,400	648,619	128,935	51,097	51,608	52,124	52,646	53,172	53,704	54,241	54,783	55,331	55,884	56,443	57,008	57,578	58,154	58,735	59,322	59,916	60,515	61,120	61,731	62,348	62,972	63,602	0	0

Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%

AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
Cost of Residential Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	7.130%	26,005	78,904	105,798	106,716	107,642	108,578	109,523	110,478	111,442	112,416	113,399	114,392	115,396	116,409	117,433	108,023	14,653	14,800	14,948	15,097	15,248	15,401	15,555	15,710	15,867	16,026	16,186
Cost of Commercial Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	7.130%	0	25,050	50,099	50,483	50,870	51,261	51,656	52,055	52,457	52,864	53,275	53,690	54,109	54,533	54,960	55,392	20,692	6,184	6,246	6,308	6,371	6,435	6,499	6,564	6,630	6,696	6,763
Installation - Residential Meters	7.130%	3,731	11,321	15,180	15,311	15,444	15,579	15,714	15,851	15,989	16,129	16,270	16,413	16,557	16,702	16,849	15,499	2,102	2,123	2,145	2,166	2,188	2,210	2,232	2,254	2,277	2,299	2,322
Installation - Commerical Meters	7.130%	0	11,540	23,079	23,256	23,434	23,614	23,796	23,980	24,166	24,353	24,542	24,734	24,927	25,122	25,319	25,518	9,532	2,849	2,877	2,906	2,935	2,964	2,994	3,024	3,054	3,085	3,116
Freight	7.130%	2,261	7,424	10,326	10,414	10,503	10,593	10,685	10,777	10,869	10,963	11,058	11,154	11,250	11,348	11,447	10,965	1,412	1,426	1,440	1,455	1,469	1,484	1,499	1,514	1,529	1,544	1,559
Billing System Configuration	7.130%	8,913	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	9,362	0	0	0	0	0	0	0	0	0	0	0	0
0	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	7.130%	407	1,336	1,859	1,875	1,891	1,907	1,923	1,940	1,956	1,973	1,990	2,008	2,025	2,043	2,060	1,974	254	257	259	262	264	267	270	272	275	278	281
Test Set & Spares Equipment	7.130%	713	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	749	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	4,203	15,483	22,559	22,731	22,904	23,078	23,255	23,433	23,613	23,795	23,979	24,164	24,352	24,541	24,732	22,951	2,736	2,764	2,791	2,819	2,848	2,876	2,905	2,934	2,963	2,993	3,023
Project Management	7.130%	2,101	7,741	11,280	11,365	11,452	11,539	11,627	11,717	11,807	11,897	11,989	11,989	11,989	11,989	11,989	5,680	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:																												
Aclara SCE materials	7.130%	5,704	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	5,992	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	7.130%	1,248	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	1,311	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	695	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	730	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	7.130%	348	695	695	695	695	695	695	695	695	695	695	695	695	695	365	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		56,329	194,038	275,420	277,390	279,380	281,389	283,419	285,469	287,540	289,631	291,743	293,784	295,845	297,927	283,298	246,003	51,382	30,402	30,706	31,013	31,323	31,637	31,953	32,272	32,595	32,921	33,250

ACCUMULATED DEPRECIATION:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	26,005	104,909	210,707	317,422	425,064	533,642	643,165	753,643	865,084	977,500	1,090,899	1,205,292	1,320,687	1,437,096	1,554,529	1,662,552	1,677,205	1,692,005	1,706,953	1,722,050	1,737,299	1,752,699	1,768,254	1,783,964	1,799,832	1,815,858	1,832,044
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	25,050	75,149	125,632	176,501	227,762	279,418	331,472	383,930	436,794	490,069	543,759	597,869	652,401	707,362	762,754	783,446	789,630	795,875	802,183	808,555	814,989	821,489	828,053	834,683	841,379	848,142
Installation - Residential Meters	0	3,731	15,052	30,232	45,543	60,987	76,566	92,280	108,131	124,121	140,250	156,520	172,933	189,490	206,192	223,041	238,540	240,642	242,766	244,911	247,077	249,265	251,474	253,706	255,960	258,237	260,536	262,858
Installation - Commerical Meters	0	0	11,540	34,619	57,875	81,310	104,924	128,720	152,701	176,866	201,220	225,762	250,496	275,423	300,544	325,863	351,381	360,913	363,762	366,639	369,545	372,480	375,445	378,439	381,462	384,517	387,601	390,717
Freight	0	2,261	9,685	20,011	30,425	40,928	51,522	62,206	72,983	83,852	94,816	105,874	117,027	128,278	139,626	151,072	162,038	163,449	164,875	166,315	167,770	169,239	170,723	172,222	173,735	175,264	176,808	178,367
Billing System Configuration	0	8,913	26,738	44,563	62,388	80,213	98,038	115,863	133,688	151,513	169,338	187,163	204,988	222,813	240,638	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	407	1,743	3,602	5,477	7,367	9,274	11,197	13,137	15,093	17,067	19,057	21,065	23,090	25,133	27,193	29,167	29,421	29,677	29,937	30,199	30,463	30,730	31,000	31,272	31,547	31,825	32,106
Test Set & Spares Equipment	0	713	2,139	3,565	4,991	6,417	7,843	9,269	10,695	12,121	13,547	14,973	16,399	17,825	19,251	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Contingency	0	4,203	19,686	42,245	64,975	87,879	110,957	134,212	157,645	181,258	205,053	229,032	253,196	277,547	302,088	326,820	349,771	352,508	355,272	358,063	360,882	363,730	366,606	369,511	372,445	375,408	378,401	381,423
Project Management	0	2,101	9,843	21,122	32,488	43,939	55,479	67,106	78,822	90,629	102,527	114,516	126,505	138,494	150,484	162,473	168,153	168,153	168,153	168,153	168,153	168,153	168,153	168,153	168,153	168,153	168,153	168,153
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	5,704	17,112	28,520	39,928	51,336	62,744	74,152	85,560	96,968	108,376	119,784	131,192	142,600	154,008	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Installation by YECL	0	1,248	3,743	6,239	8,734	11,230	13,725	16,221	18,716	21,212	23,707	26,203	28,698	31,194	33,689	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Contingency	0	695	2,086	3,476	4,866	6,257	7,647	9,037	10,428	11,818	13,208	14,599	15,989	17,379	18,770	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Project Management	0	348	1,043	1,738	2,433	3,128	3,823	4,519	5,214	5,909	6,604	7,299	7,995	8,690	9,385	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750
		56,329	250,367	525,787	803,177	1,082,556	1,363,946	1,647,365	1,932,834	2,220,374	2,510,005	2,801,749	3,095,533	3,391,378	3,689,305	3,972,603	4,218,606	4,269,988	4,300,390	4,331,096	4,362,109	4,393,433	4,425,069	4,457,022	4,489,294	4,521,890	4,554,811	4,588,061

PROPERTY IN SERVICE (beg yr):	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	364,723	1,080,640	1,378,936	1,286,005	1,192,284	1,097,767	1,002,445	906,310	809,355	711,571	612,950	513,483	413,162	311,979	209,924	106,990	13,609	13,745	13,883	14,022	14,162	14,304	14,447	14,591	14,737	14,884	15,033
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	351,328	677,605	632,882	587,829	542,443	496,721	450,660	404,255	357,504	310,404	262,950	215,139	166,968	118,433	69,530	20,256	5,743	5,801	5,859	5,917	5,976	6,036	6,097	6,158	6,219	6,281
Installation - Residential Meters	0	52,330	155,048	197,847	184,514	171,067	157,506	143,829	130,036	116,125	102,095	87,945	73,674	59,280	44,762	30,120	15,351	1,953	1,972	1,992	2,012	2,032	2,052	2,073	2,094	2,114	2,136	2,157
Installation - Commerical Meters	0	0	161,848	312,155	291,552	270,798	249,889	228,827	207,607	186,230	164,693	142,995	121,134	99,109	76,918	54,559	32,031	9,331	2,646	2,672	2,699	2,726	2,753	2,781	2,809	2,837	2,865	2,894
Freight	0	31,715	101,864	135,135	126,049	116,886	107,648	98,331	88,937	79,463	69,910	60,275	50,560	40,762	30,881	20,916	10,866	1,311	1,324	1,338	1,351	1,365	1,378	1,392	1,406	1,420	1,434	1,448
Billing System Configuration	0	125,000	241,088	223,263	205,438	187,613	169,788	151,963	134,138	116,313	98,488	80,663	62,838	45,013	27,188	9,363	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	5,709	18,335	24,324	22,689	21,040	19,377	17,700	16,009	14,303	12,584	10,850	9,101	7,337	5,559	3,765	1,956	236	238	241	243	246	248	251	253	256	258	261
Test Set & Spares Equipment	0	10,000	19,287	17,861	16,435	15,009	13,583	12,157	10,731	9,305	7,879	6,453	5,027	3,601	2,175	749	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	58,948	212,944	296,713	276,556	256,252	235,800	215,197	194,443	173,535	152,472	131,253	109,877	88,340	66,643	44,783	22,758	2,542	2,567	2,593	2,619	2,645	2,671	2,698	2,725	2,752	2,780	2,807
Project Management	0	29,474	106,472	148,356	138,278	128,126	117,900	107,599	97,221	86,767	76,236	65,627	53,637	41,648	29,659	17,669	5,680	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	80,000	154,296	142,888	131,480	120,072	108,664	97,256	85,848	74,440	63,032	51,624	40,216	28,808	17,400	5,992	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	0	17,500	33,752	31,257	28,761	26,266	23,770	21,275	18,779	16,284	13,788	11,293	8,797	6,302	3,806	1,311	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	9,750	18,805	17,414	16,024	14,634	13,243	11,853	10,463	9,072	7,682	6,292	4,901	3,511	2,121	730	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	0	4,875	9,402	8,707	8,012	7,317	6,622	5,927	5,231	4,536	3,841	3,146	2,451	1,755	1,060	365	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	790,022	2,665,108	3,612,462	3,364,674	3,115,192	2,863,999	2,611,078	2,356,412	2,099,984	1,841,775	1,581,769	1,318,645	1,053,767	787,117	518,678	265,161	49,238	28,237	28,519	28,804	29,093	29,383	29,677	29,974	30,274	30,576	30,882

Yukon Electrical AMR Project - 40% Equity, I
AMR Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	60%	0.0348	0.0348
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	40%	0.0526	0.0368
Tax Rate	30.000%		8.743%	7.164%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 8.743%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	689,400	689,400	0	(689,400)	(689,400)	0
1	Jan-15	790,022	56,597	56,329	12,473	648,619	774,018	0	(774,018)	(1,401,188)	1
2	Jan-16	2,665,108	190,928	194,038	42,078	128,935	555,980	0	(555,980)	(1,871,361)	2
3	Jan-17	3,612,462	258,797	275,420	57,036	51,097	642,349	0	(642,349)	(2,370,900)	3
4	Jan-18	3,364,674	241,045	277,390	53,123	51,608	623,167	0	(623,167)	(2,816,557)	4
5	Jan-19	3,115,192	223,172	279,380	49,184	52,124	603,861	0	(603,861)	(3,213,688)	5
6	Jan-20	2,863,999	205,177	281,389	45,218	52,646	584,430	0	(584,430)	(3,567,138)	6
7	Jan-21	2,611,078	187,058	283,419	41,225	53,172	564,874	0	(564,874)	(3,881,295)	7
8	Jan-22	2,356,412	168,813	285,469	37,204	53,704	545,191	0	(545,191)	(4,160,127)	8
9	Jan-23	2,099,984	150,443	287,540	33,156	54,241	525,379	0	(525,379)	(4,407,223)	9
10	Jan-24	1,841,775	131,945	289,631	29,079	54,783	505,438	0	(505,438)	(4,625,829)	10
11	Jan-25	1,581,769	113,318	291,743	24,974	55,331	485,366	0	(485,366)	(4,818,875)	11
12	Jan-26	1,318,645	94,468	293,784	20,820	55,884	464,956	0	(464,956)	(4,988,935)	12
13	Jan-27	1,053,767	75,492	295,845	16,637	56,443	444,418	0	(444,418)	(5,138,415)	13
14	Jan-28	787,117	56,389	297,927	12,427	57,008	423,751	0	(423,751)	(5,269,484)	14
15	Jan-29	518,678	37,158	283,298	8,189	57,578	386,223	0	(386,223)	(5,379,341)	15
16	Jan-30	265,161	18,996	246,003	4,187	58,154	327,339	0	(327,339)	(5,464,963)	16
17	Jan-31	49,238	3,527	51,382	777	58,735	114,422	0	(114,422)	(5,492,486)	17
18	Jan-32	28,237	2,023	30,402	446	59,322	92,193	0	(92,193)	(5,512,879)	18
19	Jan-33	28,519	2,043	30,706	450	59,916	93,115	0	(93,115)	(5,531,820)	19
20	Jan-34	28,804	2,064	31,013	455	60,515	94,046	0	(94,046)	(5,549,413)	20
21	Jan-35	29,093	2,084	31,323	459	61,120	94,987	0	(94,987)	(5,565,752)	21
22	Jan-36	29,383	2,105	31,637	464	61,731	95,937	0	(95,937)	(5,580,929)	22
23	Jan-37	29,677	2,126	31,953	469	62,348	96,896	0	(96,896)	(5,595,025)	23
24	Jan-38	29,974	2,147	32,272	473	62,972	97,865	0	(97,865)	(5,608,117)	24
25	Jan-39	30,274	2,169	32,595	478	63,602	98,844	0	(98,844)	(5,620,277)	25
26	Jan-40	30,576	2,190	32,921	483	0	35,594	0	(35,594)	(5,624,303)	26
27	Jan-41	30,882	2,212	33,250	488	0	35,950	0	(35,950)	(5,628,044)	27
28	Jan-42	31,191	2,235	33,583	492	0	36,310	0	(36,310)	(5,631,517)	28
29	Jan-43	(2,392)	(171)	(2,393)	(38)	0	(2,602)	0	2,602	(5,631,288)	29
30	Jan-44	1	0	0	0	0	0	0	(0)	(5,631,288)	30
31	Jan-45	1	0	0	0	0	0	0	(0)	(5,631,288)	31
32	Jan-46	1	0	0	0	0	0	0	(0)	(5,631,288)	32
33	Jan-47	1	0	0	0	0	0	0	(0)	(5,631,288)	33
34	Jan-48	1	0	0	0	0	0	0	(0)	(5,631,288)	34
35	Jan-49	1	0	0	0	0	0	0	(0)	(5,631,288)	35
36	Jan-50	1	0	0	0	0	0	0	(0)	(5,631,288)	36
37	Jan-51	1	0	0	0	0	0	0	(0)	(5,631,288)	37
38	Jan-52	1	0	0	0	0	0	0	(0)	(5,631,288)	38
39	Jan-53	1	0	0	0	0	0	0	(0)	(5,631,288)	39
40	Jan-54	1	0	0	0	0	0	0	(0)	(5,631,288)	40

Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	32,375	65,074	66,055	67,046	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	32,375	65,074	66,055	67,046	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

O&M:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Manual Meter Reading Costs	0	465,408	470,062	474,763	479,510	484,305	489,148	494,040	498,980	503,970	509,010	514,100	519,241	524,433	529,678	534,974	540,324	545,727	551,185	556,697	562,264	567,886	573,565	579,301	585,094	590,945	596,854	602,823
Meter Test Costs	0	73,528	74,263	75,006	75,756	76,514	17,388	17,562	17,737	17,915	18,094	18,275	18,457	18,642	18,828	19,017	19,207	19,399	19,593	19,789	19,987	20,187	20,388	20,592	20,798	21,006	21,216	21,428
Customer Applications & Service Or	0	136,350	137,714	139,091	140,482	141,886	143,305	144,738	146,186	147,648	149,124	150,615	152,121	153,643	155,179	156,731	158,298	159,881	161,480	163,095	164,726	166,373	168,037	169,717	171,414	173,128	174,860	176,608
Data Cap Costs	0	21,008	21,218	21,430	21,645	21,861	22,080	22,300	22,523	22,749	22,976	23,206	23,438	23,672	23,909	24,148	24,390	24,634	24,880	25,129	25,380	25,634	25,890	26,149	26,410	26,675	26,941	27,211
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	0	696,294	703,257	710,290	717,392	724,566	671,921	678,640	685,427	692,281	699,204	706,196	713,258	720,390	727,594	734,870	742,219	749,641	757,137	764,709	772,356	780,079	787,880	795,759	803,717	811,754	819,871	828,070

Yukon Electrical AMR Project - 40% Equity, Inflation Factor of 1%
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	8.090%	2,619	7,884	13,227	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	1,653	0	0	0	0	0	0	0	0	0	0	0	0
2)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		2,619	7,884	13,227	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	18,651	1,653	0	0	0	0	0	0	0	0	0	0	0	0

ACCUMULATED DEPRECIATION	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	2,619	10,503	23,730	42,382	61,033	79,684	98,336	116,987	135,639	154,290	172,942	191,593	210,244	228,896	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549	230,549
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PROPERTY IN SERVICE (beg yr	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	32,375	94,830	153,001	206,819	188,167	169,516	150,865	132,213	113,562	94,910	76,259	57,608	38,956	20,305	1,653	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	32,375	94,830	153,001	206,819	188,167	169,516	150,865	132,213	113,562	94,910	76,259	57,608	38,956	20,305	1,653	0	0	0	0	0	0	0	0	0	0	0	0

Yukon Electrical AMR Project - 40% Equ
Conventional Meter Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	60%	0.0348	0.0348
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	40%	0.0526	0.0368
Tax Rate	#####		8.743%	7.164%

CASH FLOWS SUMMARY:

Year		Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 8.743%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	0	0	0	0	0	0
1	Jan-15	32,375	2,319	2,619	511	696,294	701,744	0	(701,744)	(645,324)	1
2	Jan-16	94,830	6,794	7,884	1,497	703,257	719,431	0	(719,431)	(1,253,722)	2
3	Jan-17	153,001	10,961	13,227	2,416	710,290	736,894	0	(736,894)	(1,826,785)	3
4	Jan-18	206,819	14,817	18,651	3,265	717,392	754,126	0	(754,126)	(2,366,098)	4
5	Jan-19	188,167	13,480	18,651	2,971	724,566	759,669	0	(759,669)	(2,865,696)	5
6	Jan-20	169,516	12,144	18,651	2,676	671,921	705,393	0	(705,393)	(3,292,302)	6
7	Jan-21	150,865	10,808	18,651	2,382	678,640	710,482	0	(710,482)	(3,687,439)	7
8	Jan-22	132,213	9,472	18,651	2,087	685,427	715,637	0	(715,637)	(4,053,444)	8
9	Jan-23	113,562	8,136	18,651	1,793	692,281	720,861	0	(720,861)	(4,392,479)	9
10	Jan-24	94,910	6,799	18,651	1,498	699,204	726,153	0	(726,153)	(4,706,545)	10
11	Jan-25	76,259	5,463	18,651	1,204	706,196	731,514	0	(731,514)	(4,997,492)	11
12	Jan-26	57,608	4,127	18,651	910	713,258	736,946	0	(736,946)	(5,267,035)	12
13	Jan-27	38,956	2,791	18,651	615	720,390	742,448	0	(742,448)	(5,516,756)	13
14	Jan-28	20,305	1,455	18,651	321	727,594	748,021	0	(748,021)	(5,748,124)	14
15	Jan-29	1,653	118	1,653	26	734,870	736,668	0	(736,668)	(5,957,661)	15
16	Jan-30	0	0	0	0	742,219	742,219	0	(742,219)	(6,151,803)	16
17	Jan-31	0	0	0	0	749,641	749,641	0	(749,641)	(6,332,122)	17
18	Jan-32	0	0	0	0	757,137	757,137	0	(757,137)	(6,499,602)	18
19	Jan-33	0	0	0	0	764,709	764,709	0	(764,709)	(6,655,156)	19
20	Jan-34	0	0	0	0	772,356	772,356	0	(772,356)	(6,799,634)	20
21	Jan-35	0	0	0	0	780,079	780,079	0	(780,079)	(6,933,825)	21
22	Jan-36	0	0	0	0	787,880	787,880	0	(787,880)	(7,058,461)	22
23	Jan-37	0	0	0	0	795,759	795,759	0	(795,759)	(7,174,223)	23
24	Jan-38	0	0	0	0	803,717	803,717	0	(803,717)	(7,281,742)	24
25	Jan-39	0	0	0	0	811,754	811,754	0	(811,754)	(7,381,605)	25
26	Jan-40	0	0	0	0	819,871	819,871	0	(819,871)	(7,474,358)	26
27	Jan-41	0	0	0	0	828,070	828,070	0	(828,070)	(7,560,506)	27
28	Jan-42	0	0	0	0	836,351	836,351	0	(836,351)	(7,640,521)	28
29	Jan-43	0	0	0	0	0	0	0	(0)	(7,640,521)	29
30	Jan-44	0	0	0	0	0	0	0	(0)	(7,640,521)	30
31	Jan-45	0	0	0	0	0	0	0	(0)	(7,640,521)	31
32	Jan-46	0	0	0	0	0	0	0	(0)	(7,640,521)	32
33	Jan-47	0	0	0	0	0	0	0	(0)	(7,640,521)	33
34	Jan-48	0	0	0	0	0	0	0	(0)	(7,640,521)	34
35	Jan-49	0	0	0	0	0	0	0	(0)	(7,640,521)	35
36	Jan-50	0	0	0	0	0	0	0	(0)	(7,640,521)	36
37	Jan-51	0	0	0	0	0	0	0	(0)	(7,640,521)	37
38	Jan-52	0	0	0	0	0	0	0	(0)	(7,640,521)	38
39	Jan-53	0	0	0	0	0	0	0	(0)	(7,640,521)	39
40	Jan-54	0	0	0	0	0	0	0	(0)	(7,640,521)	40

UCG-YECL-126

Reference: May 27, 2013 Application, Business Case #28

Fish Lake Water Licence Renewal

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #28 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1 and YUB-YECL-53(a) Attachment 1

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. Please refer to YUB-YECL-8 Attachment 1 for a breakdown of operating costs related to hydro generation.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical's forecast of costs for this project has increased from the amount included in the Application. Please refer to YUB-YECL-53(a) Attachment 1 for a breakdown of the updated forecast for 2013.

UCG-YECL-127

Reference: May 27, 2013 Application, Business Case #29

Downtown Office Building Envelope Upgrades

Request:

(a) Pursuant to the components of business cases identified in YUB Order 2009-8, please identify where in Business Case #29 the following has been provided:

- economic analysis including preliminary engineering estimates
- discussion of the risks of proceeding with the chosen alternative
- discussion of risks of not proceeding with the chosen alternative; and
- discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs.

(b) Please provide details of capital and operating costs related to this project as well as the discounted cash flow analysis used by YECL to determine the feasibility of proceeding with this project.

(c) Please provide the confidence level associated with the proposed capital cost of this project.

Response:

(a) Yukon Electrical has provided a business case that contains the following information as part of its Application:

- Summary
- Project Description
- Project Cost
- Business and Technical Drivers
- Alternatives
- Recommendation

As well, a breakdown of the project costs has been provided in YUB-YECL-61 Attachment 1.

(b) Please refer to YUB-YECL-61 Attachment 1 for a breakdown of the capital costs related to the project. There are no operating costs related to this project.

No discounted cash flow analysis was used by Yukon Electrical to determine the feasibility of proceeding with this project.

(c) Yukon Electrical continues to be confident in the forecast capital cost of this project.

UCG-YECL-128

Reference: May 27, 2013 Application, Business Case #30 - DSM

Based on full implementation of the five year DSM plan, the Utilities commit to an electricity conservation target of 8.5 GWh of sustained savings by year five.

Request:

(a) The utilities state (page 3) that the proposed DSM Plan "was developed by the utilities in collaboration with interveners, Yukon NGOs, community leaders, First Nation governments and the general public". Please provide details of presentations made and discussions held by the utilities regarding the proposed DSM plan with the each of these stakeholder groups prior to submitting it to the YUB on May 27, 2013. Please include details of how many individuals from these stakeholder groups were involved in each consultation.

(b) Why did the utilities not consult with builders, building contractors and trades specialists?

(c) Please provide details of any discussions, surveys, etc. that the utilities conducted of customer groups to determine if it should offer DSM programming.

(d) Please provide a table that lists all customer classes who have participated in the DSM programs either offered or supported by the utilities from 2008-2012. In the table include the number of programs each customer has participated in, the year(s) they were a participant, if the program was a standard resource acquisition program or a large industrial/commercial specific program, the amount of incentive dollars received by each participant (divided by year), and the cumulative electricity savings achieved each year. (redact the names of the customers if necessary)

(e) Please advise how much less electricity in kWh was being consumed in the Yukon in 2012 as a result of the DSM programs delivered by the utilities since 2008. Please provide specific details on the measurement of this amount.

(f) How much of the proposed DSM plan is targeted at ratepayers living on low and/or fixed incomes? Please compare this to the proportion of DSM programs in other jurisdictions that are dedicated to low income ratepayers.

(g) Please provide a table that lists of all the programs the utilities considered for inclusion in its DSM Plan, the TRC ratio for each program, the cost for each program and the rationale for or against proceeding with the program.

(h) Please confirm that for savings to be eligible to be counted towards the DSM savings targets, the savings must be verified using industry-based evaluation, measurement and verification protocols. Please provide the EM&V protocols that the utilities will be using.

(i) How will the annual results of the proposed DSM program be audited and by whom?

(j) How will the savings generated by utility-sponsored DSM programs be isolated from savings resulting from Yukon government-sponsored DSM and energy conservation programs?

(k) Please set out all steps that the utilities will take over the term of the proposed DSM plan to ensure that all parties have confidence in the electricity savings delivered within the DSM portfolio.

(l) In this and other programs that are based on the level of efficiency in the Yukon's Building Standards Act and the National Building Code, there is a fundamental expectation that all builders fully comply with the legislation and that the performance of the homes and buildings once built and in operation actually achieve the levels anticipated by the legislation. Have the utilities done any research to determine if such assumptions are valid? Are the utilities aware of any research by any other organization or agency to validate the performance of homes and buildings relative to legislated assumptions? If it is the case that homes and buildings are not performing as expected under the Code, would not the utilities' estimates of the impact of its DSM programs to go beyond Code actually understate the savings achieved?

(m) Are the utilities seeking approval of all the elements of the proposed DSM Plan for five years? To the extent that the utilities wish to make changes to the proposed DSM Plan during this five-year period, what process is proposed in order to obtain Board approval for those changes?

(n) Please explain how the utilities will allocate the costs of the proposed DSM Plan between the various rate classes. Does the allocation of these costs take into

account differences between the participation levels and savings per participant between the various customer classes?

(o) Please provide a table (or tables) showing for 2008, 2009, 2010, 2011, 2012, 2013, 2014 and 2015 how the DSM costs are allocated to each rate class. In showing the DSM costs allocated to each rate class, please indicate the average rate impact for each rate class.

(p) Please identify all advantages associated with approval of a 5-year DSM framework rather than a 1-year DSM framework.

(q) Please identify the advantages associated with approval of a 1-year DSM framework rather than a 5-year DSM framework.

(r) Have the utilities identified any cost efficiencies with proceeding with a 5-year DSM framework rather than a 1-year DSM framework? If so, please identify all those cost efficiencies. Further, if cost efficiencies have been identified, please explain how those cost efficiencies are passed on to ratepayers.

(s) Do the utilities agree that large industrial customers have the expertise to undertake energy efficiency programs on their own so ratepayer funded DSM programs for large industrial customers should not be mandatory?

(t) What penalties will be incurred by the utilities if they do not meet the electricity conservation target of 8.5 GWh of sustained savings by year five?

(u) In order to adequately challenge the utilities to drive increased participation to target levels, have the utilities considered the use of a variance account such that the utilities will only be reimbursed up to a maximum amount based on achievement of targeted savings levels?

(v) What market barriers have the utilities identified to providing DSM to privately-owned multi-unit residential buildings?

(w) Have the utilities studied other jurisdictions that are providing DSM programs to privately-owned multi-unit residential buildings? If yes, please provide the related research.

(x) Have the utilities analyzed the potential impacts of system level efficiency savings on the price ratepayers pay for electricity? If so, please provide the analysis.

(y) What is the target reduction in peak electricity demand over the 5 year plan period?

(z) What is the required take-up of each proposed DSM program in order to ensure that the savings target will be achieved?

(aa) Please provide any market potential studies / working papers that relate to the housing stock targeted by the proposed DSM plan for social housing units.

Response:

(a) Consultation and workshops with stakeholders began in January 2011 and continued through to June 2013 when the final program design was rolled out to the public. The materials presented along with attendance information, where available, is attached in the following documents:

- *Alexco Presentation Apr2012* (UCG-YECL-128(a) Attachment 1)
- *AYC Presentation Nov2012* (UCG-YECL-128(a) Attachment 2)
- *CPR Kickoff May2011* (UCG-YECL-128(a) Attachment 3)
- *CPR Study visit May2011* (UCG-YECL-128(a) Attachment 4)
- *DSM Working Group Presentation Apr2012* (UCG-YECL-128(a) Attachment 5)
- *DSM Workshop Report Apr2012* (UCG-YECL-128(a) Attachment 6)
- *DSM Workshop Apr2012* (UCG-YECL-128(a) Attachment 7)
- *DSM for the Yukon June2013* (UCG-YECL-128(a) Attachment 8)
- *Focus Group Workshop Jan2011* (UCG-YECL-128(a) Attachment 9)
- *John Streicker Presentation Apr2012* (UCG-YECL-128(a) Attachment 10)
- *One Change Consultation June2011* (UCG-YECL-128(a) Attachment 11)
- *UCG Presentation Apr2012* (UCG-YECL-128(a) Attachment 12)
- *YCS Presentation Apr2012* (UCG-YECL-128(a) Attachment 13)
- *YEC Charette March2011* (UCG-YECL-128(a) Attachment 14)
- *Workshop Attendance Nov2011* (UCG-YECL-128(a) Attachment 15)
- *CPR Workshop May2011* (UCG-YECL-128(a) Attachment 16)

(b) The utilities consulted with builders, building contractors and trade specialists through the market characterization process. Please refer to the *DSM Market Characterization Methodology*, provided as UCG-YECL-128(b) Attachment 1, for details.

(c) Please refer to the attached documents of details of surveys conducted with customers.

- *One Change Survey June 2011* (UCG-YECL-128(c) Attachment 1)
- *YEC Knowledge Awareness Opinion Survey* (UCG-YECL-128(c) Attachment 2)
- *YEC Public and Stakeholder Survey July 2011* (UCG-YECL-128(c) Attachment 3)
- *YEC Public and Stakeholder Survey June 2010* (UCG-YECL-128(c) Attachment 4)

(d) There were no programs under the joint DSM plan delivered from 2008-2012, so no customer participation information can be provided.

(e) There were no programs under the joint DSM plan delivered from 2008-2012, so there was no reduction in electricity consumption as a result of DSM for the period.

(f) The utilities have no visibility of ratepayer income levels.

(g) The DSM programs were developed based on a set of considered technologies for application in programs. A Total Resource Cost Test (TRC) was not performed on programs, but on individual measures as part of the four cost effectiveness tests. The TRC on the selected measures are detailed in *DSM Program Incentive Justification Levels*, provided as YUB-YECL-27 Attachment 1.

The first task in the planning process was to determine which of the several hundred technologies and measures analyzed in the Yukon CPR 2011 were appropriate for the Yukon context *(*details can be found in *Appendices G1-G4* of the *Yukon Five Year Demand Side Management Plan* filed with the Application*)*. As a starting point in the extensive listing of individual measures and technologies contained in the Conservation Potential Review, results were screened using a 7 step process as outlined below (taken from Exhibit 2, page 3, Appendix E of the *Yukon Five Year Demand Side Management Plan* filed with the Application):

Exhibit 2: Priority Opportunities Screening Process

Step 1: The Economic Potential and Achievable Potential results for the residential and commercial sectors were sorted on the basis of the following criteria:

- Measures providing the largest electricity savings potential by Y3 and by 2020
- Measures providing electricity savings at the lowest levelized cost
- Measures providing electricity savings with the shortest customer payback

Step 2: Based on the results of Step 1, individual measures were assigned priority, with highest priority assigned to those measures that provided the largest savings potential in the period at the lowest levelized cost of electricity under the total resource cost test (see 1.3.3 below).

Step 3: Priority measures from Step 2 were grouped into "opportunity areas" e.g., multiple individual commercial lighting measures were combined into a single aggregate "commercial lighting" opportunity. As applicable, complementary measures with smaller savings potential and/or higher levelized costs of electricity were added to the applicable opportunity area. The composition of the package of measures contained in the selected opportunity areas also considered factors such as: commonality of market delivery channels, information flows, typical purchase decision making processes etc.

Step 4: The qualitative notes from the CPR achievable potential workshops were reviewed to determine if participants had noted any compelling technology or market considerations, either positive or negative, that would potentially affect the priorities established in Step 3. Customer payback periods, as generated in Step 1, were also considered at this time. The assigned priority for each "opportunity area" was adjusted, as applicable.

Step 5: A brief scan of DSM program experience in other jurisdictions was conducted with the objective of identifying potential program delivery experience that would affect the priorities established in Step 3. The assigned priority for each "opportunity area" was adjusted, as applicable.

Step 6: The estimated upper and lower achievable potential electricity savings for the resulting combined residential and commercial sector opportunity areas was calculated, together with an approximate weighted average CCE for each opportunity area. The results were compared with the notional 5 GWh/year savings target.

Step 7: A select number of opportunity areas were recommended for this initial set of DSM programs.

(h) Confirmed. The utilities' Evaluation, Measurement and Verification Plan will follow the general principles of the California Evaluation Framework and the California Evaluation Protocols as these are the standard reference books utilized across North America. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details of the protocols that will be utilized.

(i) The utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities. Third-party evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. The utilities intend to follow the general principles of the California Evaluation Framework and the California Evaluation Protocols as these are the standard reference books utilized across North-America. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details of how annual results will be calculated and verified.

(j) The electricity saving achieved by the five-year DSM plan will be evaluated and verified by the process set-out in the EM&V plan. This plan uses a deemed savings approach and is specific to the measures outlined in the Program Portfolio. Government sponsored programs will not be part of the reporting of the five-year DSM plan. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for further details of how the utilities will report savings.

(k) The utilities' DSM staff will track a set of indicators to justify results, suggest corrective measures, and update targets for the next period. Additionally, the utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities. Third-party program evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. Please refer to section 3, pages 13-24 of the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for an overview of EM&V for the proposed DSM program portfolio. Additional EM&V process details by program can be found in the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

(l) The utilities have not done any research to determine if the assumptions regarding builder compliance with legislation and performance of buildings once built are valid.

The utilities are not aware of any specific research related to validating the performance of homes and buildings. Compliance with the code is the generally-accepted baseline scenario among utilities and DSM program administrators.

The utilities expect on average that buildings will perform to the National Building Code and the Yukon's Building Standards Acts as it applies to to the modeling completed as part of the DSM study. The utilities' approach to estimate the impact will match in rigor that of other North American utilities. Buildings that exceed building code standards or do not meet them would have varying results.

(m) Yes, the utilities are seeking approval for the five year plan. Please refer to the *DSM Program Evaluation, Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for details related to Board communication regarding changes in the programs.

(n) This question will be examined as part of a future Phase II process.

(o) This question will be examined as part of a future Phase II process.

(p) The advantages associated with approval of a five-year DSM framework are:

- Drafting a new DSM portfolio application every year would require a considerable investment in time and materials; either requiring the involvement of external consultants or pulling the program management staff out of their regular operations. This would then impact customer satisfaction and program performance.

- Stability of the program portfolio / Lower risk of abrupt changes in policy, or programs being cancelled without proper exit strategy.

    - Both end-users and trade allies want to be able to trust in the availability of the programs when planning capital investment. This, stability will increase both customer satisfaction and program uptake.

    - The utilities can carefully plan communications around anticipated program changes and evolutions, as applicable.

- Greater job stability for DSM staff. Stable, seasoned and talented DSM staff will result in greater customer satisfaction, and higher impact.

- Greater flexibility provided to the utilities to react to changing market conditions, early results and feedback from customers and trade allies.

    - Performance will still be reported to the regulator on an annual basis as well as anticipated changes, they will be commented on, and the utilities will account for the comments when implementing the changes.

- Best value third-party evaluation, measurement and verification:

    - More methodological options are available to evaluators when working with more participation data and more transactions. For example: sampling, billing analysis.

    - Program-induced transformations in the markets are challenging to observe in a timeframe that is less than 5 years.

    - One-year worth of evaluation budget in the Yukon is inadequate. It is not enough “critical mass” to cover the base cost of doing business with a seasoned EM&V contractor and would reflect badly on the quality of the evaluation work.

- 5 years is sufficient time to take the program portfolio to market, and then register results and market feedback in sufficient volume.

    - Launching a portfolio from scratch requires building a transactional infrastructure, communication materials, reassign/hire and train staff, and get the word out about the program. It takes a few months before the first residential transaction is actually recorded, and then only a few months later will the portfolio be in full swing – beyond the 1-year time window.

    - Moreover, the program portfolio has commercial/institutional DSM initiatives in the mix. Transactions in this sector are slower to develop because investments in the commercial/institutional sector are generally planned by the prospective participants one year ahead or more. The first general-service transactions might only be registered on the second year of operation.

- Because of the above, assessing the program after one or even two years of operation would be premature.

(q) A one-year plan would allow for a higher level of scrutiny of the programs. For the reasons listed in question UCG-YECL-128(p), the utilities did not feel that a one-year plan was cost-effective, nor that a one-year time frame would allow for proper evaluation, measurement and verification or a high level of customer service.

(r) Yes. The utilities have identified cost efficiencies with proceeding with a 5-year DSM framework rather than a 1-year framework.

- Drafting a new DSM portfolio application every year will require a considerable investment in time and materials, either requiring the involvement of external consultants or pulling the program management staff out of their regular operations, which would then impact customer satisfaction and program performance.

- The standard practice is to have the Conservation Potential Review (CPR) updated for a jurisdiction, in this case the Yukon, every 5th year. There is value in using the CPR result to re-shape the portfolio for the next DSM operation window.

- The EM&V budget will hardly reach a critical mass in one year, which would therefore make it not worthwhile.

- The size of the Yukon jurisdiction makes it challenging to plan and deliver a cost-effective DSM portfolio in one year versus five years.

(s) The utilities have no visibility of the expertise of their industrial customers.

(t) No penalties will be incurred.

(u) No, the utilities have not considered this approach.

(v) In the Market Characterization Research it was concluded that:

> …many apartment blocks in the Yukon were built in the 70's and they were paid for a long time ago. The owners do not need electricity efficiency to remain price competitive, the good energy rebate [offered by ESC] for instance seemed insufficient to tackle

this barrier. (Section 4.1, page 66, Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application)

(w) No, the utilities did not examine other jurisdictions related to privately-owned multi-unit residential buildings.

(x) System-wide efficiency savings are not part of the joint DSM plan.

(y) All programs included in the DSM Plan have coincidental peak savings, as outlined for each program shown in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management* Plan included in the Application. There are no specific programs to address peak shifting included in the DSM plan. Peak shifting programs tend to be costly and complex to administer as they require a high degree of customer participation and generally require enforceable regulation to ensure the technology is used during those peak times. Under the current rate structure and customer available data, there is no customer incentive to develop programing to address peak shifting. In developing their first DSM programs, the utilities focused on electricity usage savings which is more cost effective and results in coincidental peak savings.

(z) Each program within the five-year DSM plan has annual participation rates identified. The participant take-up rate for each program is detailed in UCG-YECL-128(z) Attachment 1.

(aa) There are no specific targeted programs for social housing units and no studies were undertaken.

ALEXCO

Demand Side Management
&
Audit Review

April 2012

ALEXCO

Keno Hill Project Overview

KEY Reasons for Involvement

2011 Demand Side Management Energy Audit

- Mutually beneficial partnership between YEC & Alexco

- Identified areas which allow Alexco to:
  - ✓ Reduce peak usage
  - ✓ Reduce total energy usage
  - ✓ Identify possible efficiencies
  - ✓ Further reduce energy footprint

ALEXCO

Demand Side Energy Consultants

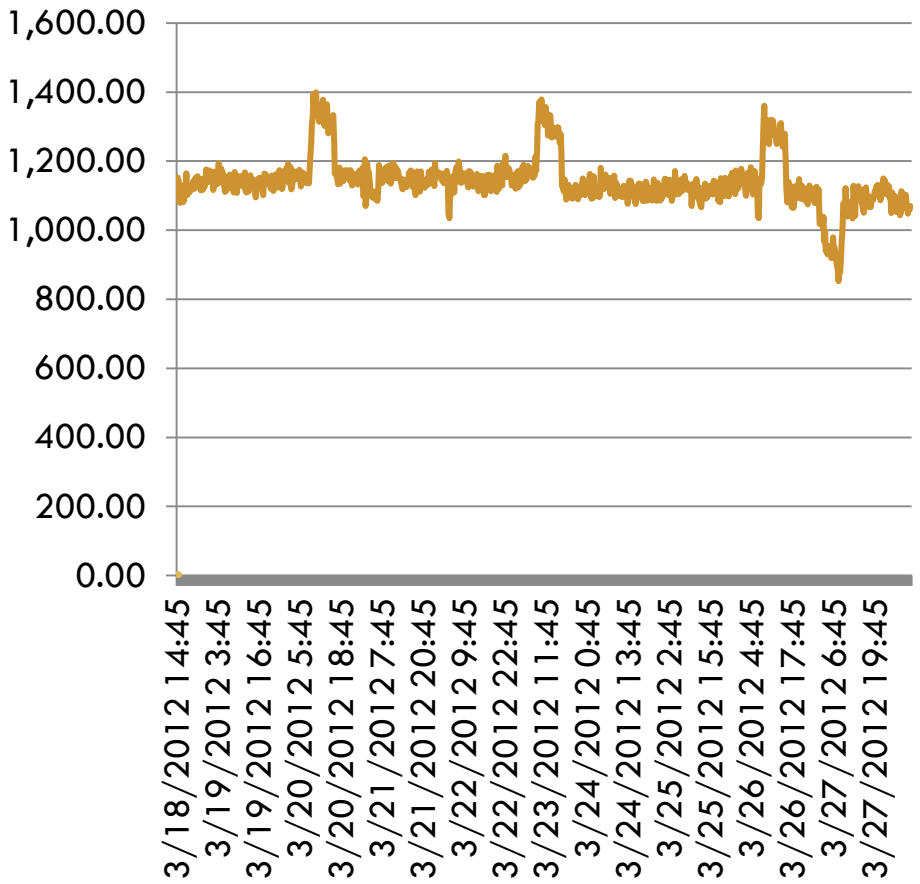
Study Scope

1.	2.	3.	4.
Observation of Keno Hill Project operational procedures	**Comparison of other projects to Keno Hill Project**	**Analysis of utilization rates & operational parameters**	**Final report & recommendations to Alexco & YEC**
1 week at site Off-site consulting work	Database comparison for efficiency gains	Large equipment such as: air compressors, crushers, blower, ball mill …	Operational recommendations & capital projects

ALEXCO

Typical Energy Profile

- Base Load = Daily Steady State Operations
- All infrastructure must be sized to peak load
- Peaks are associated with ore crushing operations



ALEXCO

Recommendations of Demand Side Audit

1. Instillation of an ammeter in Mill operators cab
2. Convert plant lighting to T5 HO fluorescents & LED's for outdoors
3. Re-commission mill air system
4. Initiate compressed air leak reduction program
5. Commission the air blower inlet modulation
6. Re-apply variable frequency drives to Mine ventilation
7. Optimize plant process thru program logic controller
8. Install electrical sub-metering for Mine
9. kWh per tonne as performance measure
10. Install capacitors on the 600V Mill

ALEXCO

Status of Recommendations

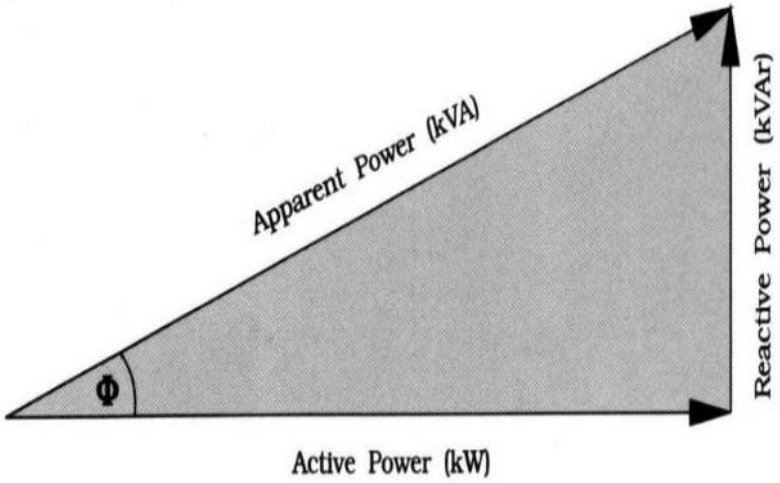
- ✓ Investigation of alternate lighting options (LED's) - in progress
- ✓ Mill compressed air system has been re-commissioned
- ✓ Ongoing air leak reduction program at Mill & Mine
- ✓ Additional variable frequency drives have been installed
- ✓ Program logic control on filter presses implemented
- ✓ Evaluation of site power distribution & metering options - in progress
- ✓ Cost benefit analysis & design of power factor correction unit for the Mill – in progress

ALEXCO

Power Factor (PF)

- Power Factor is a measure of how effectively the power is being used and is a ratio of "active power" used to the "apparent power" required which is a combination of both active power & reactive power

- 0.85 for normal operations
- 0.75 for peak loading conditions
  - For every unit of power required to run upwards of 15-20% more power needs to be provided
- 0.95 – 0.98 PF with correction



- **PF = Active Power / Apparent Power**

ALEXCO

Future Considerations

- Increased use of variable frequency drives on motors
- Power factor correction studies
- Energy measuring devices
- Alternative lighting sources
- Proper equipment sizing & selection
- Ongoing evaluation of operational practices

Alexco Contact Info

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Elsa, Yukon Y0B 1G0
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The Value of Electricity Conservation

A presentation for AYC from Yukon Energy Corporation and Yukon Electrical Company Limited

1. **What** is electricity conservation?
2. **Why** should we conserve?
3. **How much** are we using?
4. **Where** can we start?
5. What comes next?

What is electricity conservation?

1. People making the best use of the electricity that is available

2. Increased efficiency of buildings, products, and processes

Why should we conserve?

Implementing new technologies could considerably reduce your annual operating budget

Implementing new ways of doing the same old thing could save your employees time AND save money on your electricity bill

Electricity savings = $ savings

Why should we conserve?

Environmental stewardship is important to many communities and their citizens

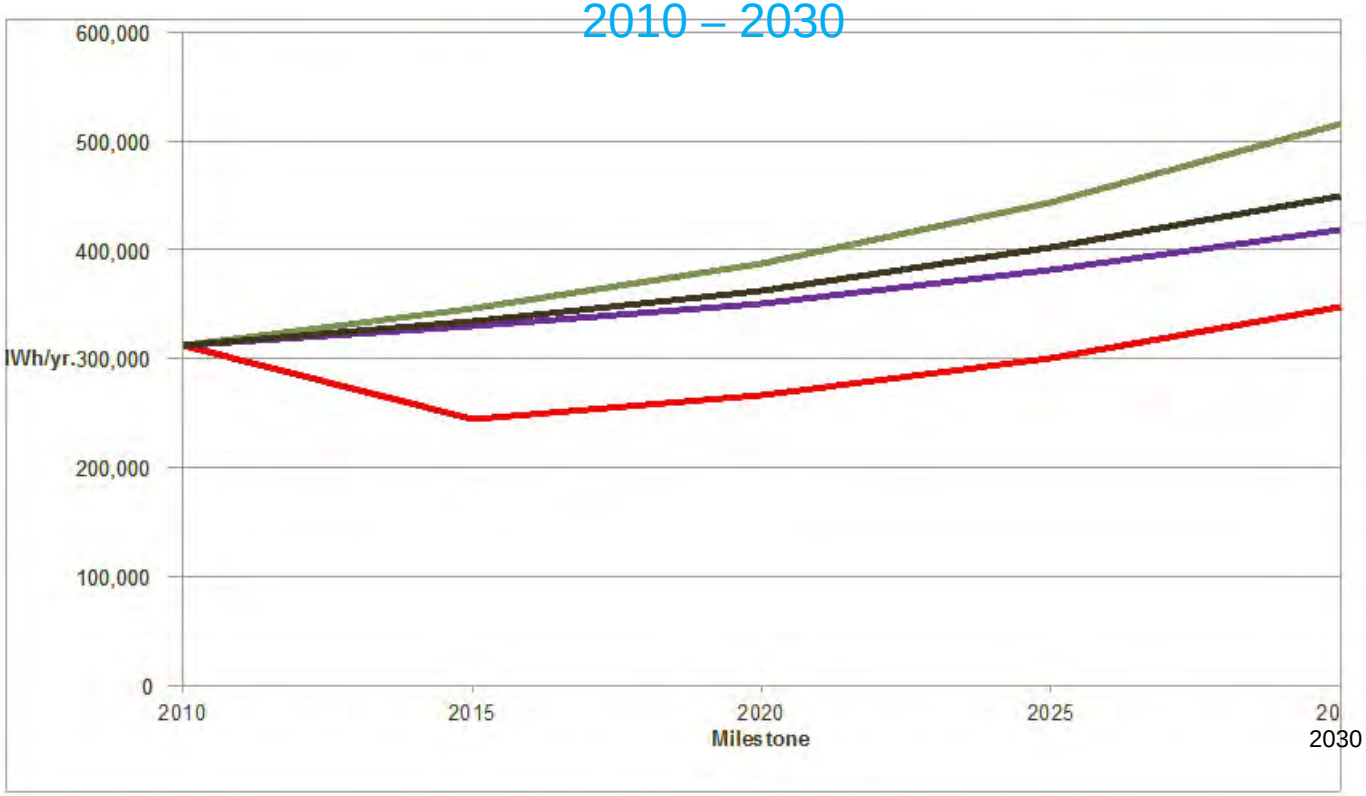
ICSPs/OTOF

The Yukon's supply of renewable resources is **limited**; Conservation is a renewable resource that **all Yukoners** can participate in providing

Electricity savings = responsible resource management

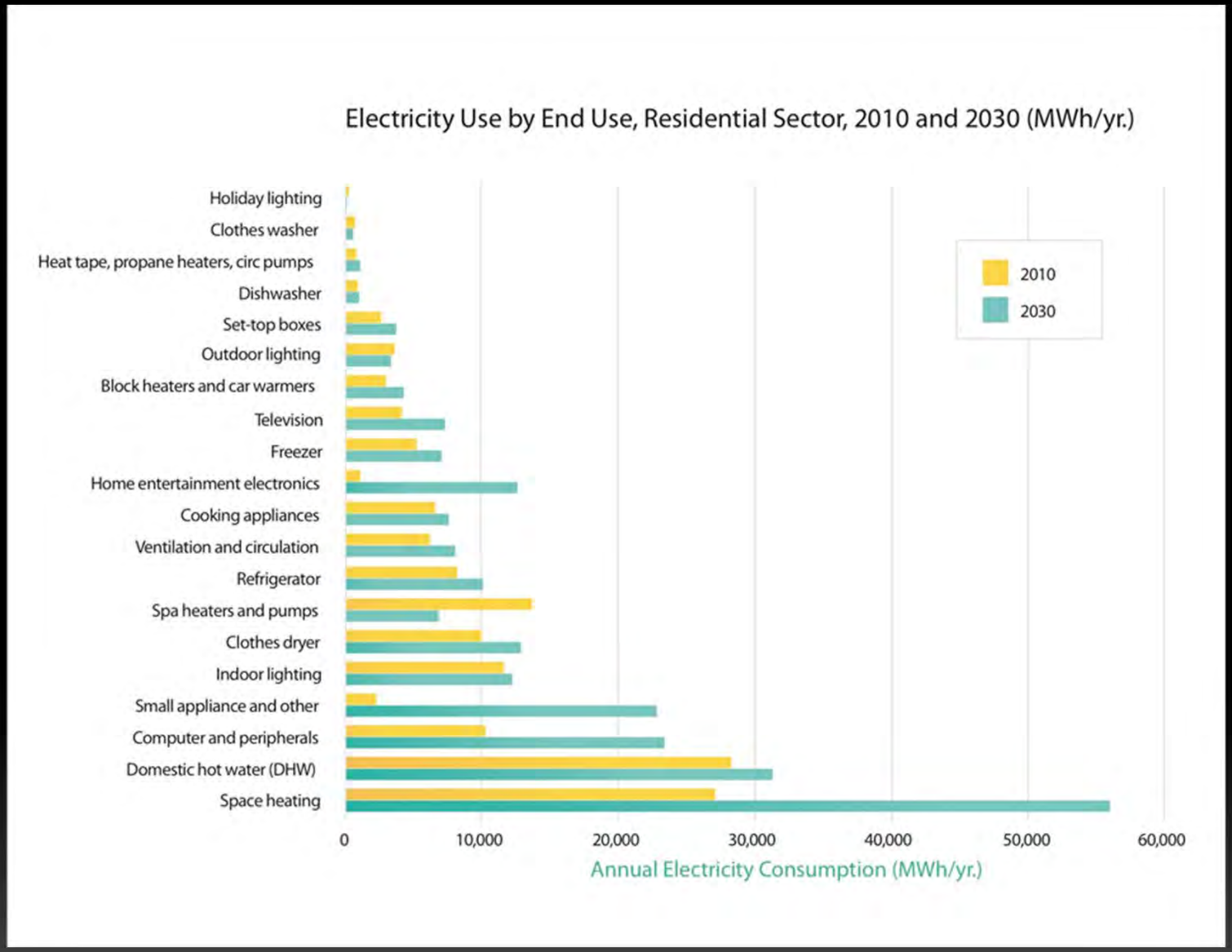
WHY SHOULD WE CONSERVE?

Growth in Residential and General Service electricity usage in Yukon (MWh/yr) 2010 – 2030



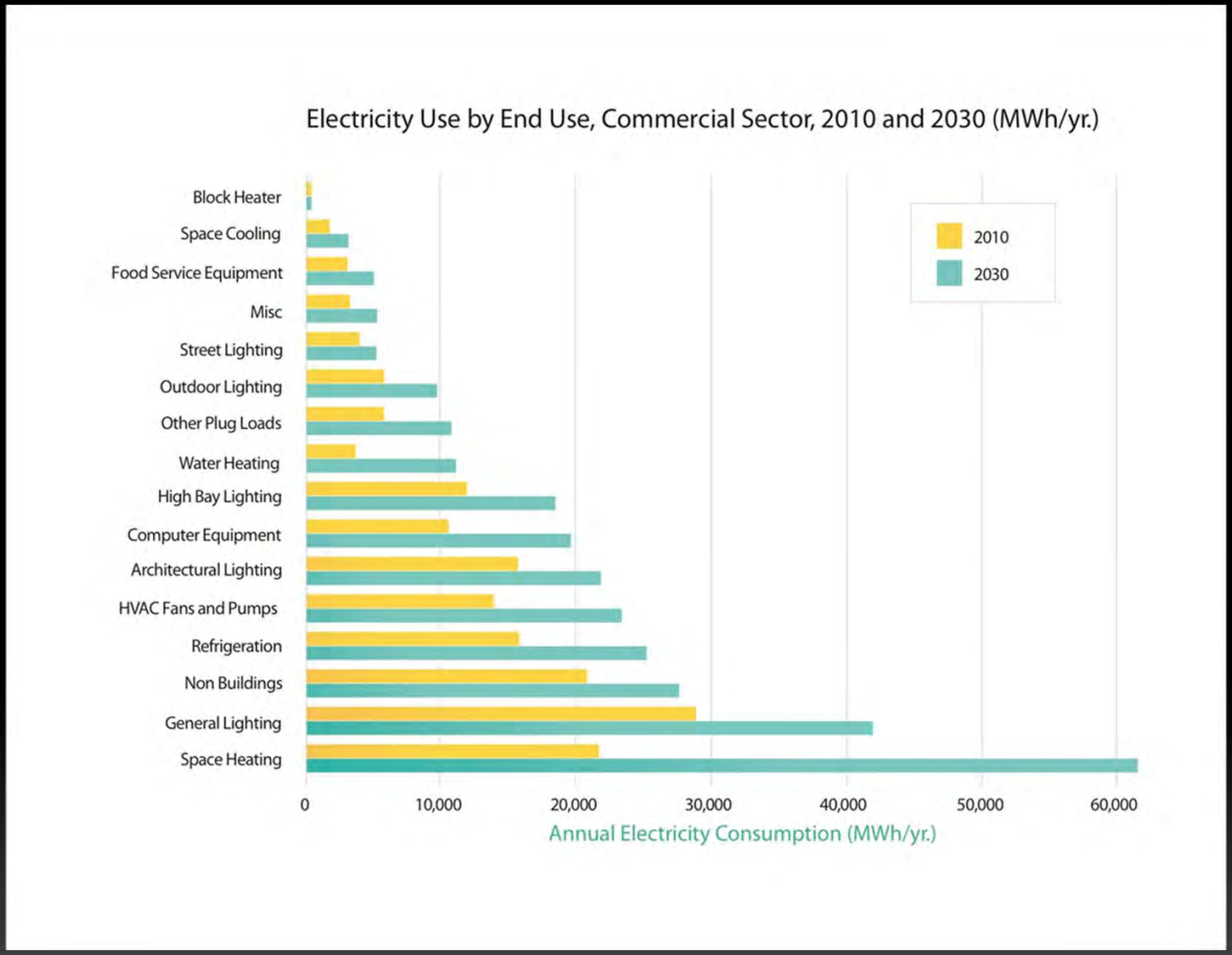
Green represents anticipated growth of electricity necessary to supply the Residential and General Service rate classes 2010-2030. Black and purple lines represent the achievable potential of conservation to impact growth.

HOW MUCH ARE WE USING?



The graph above describes the ways we use electricity in the residential sector, how much each of those uses contributes to electricity consumption and how we expect that to grow between 2010 and 2030. All numbers are based on real Yukon data.

HOW MUCH ARE WE USING?



The graph above describes the ways we use electricity in the general service sector, how much each of those uses contributes to electricity consumption and how we expect that to grow between 2010 and 2030. All numbers are based on real Yukon data.

How much are we using?

- Dollars to Sense courses
  - http://oee.nrcan.gc.ca/industrial/training-awareness/2442
- Energy Benchmarking tools
  - http://oee.nrcan.gc.ca/industrial/technical-info/benchmarking/4377#energy-performance
- Energy audits
- Reading your bill
  - http://www.yukonenergy.ca/customer/tips_tools/reading/
  - YECL link

Knowledge is Power

Understanding how your buildings and processes are using electricity can help you make informed choices about electricity conservation projects

Completing a desktop **audit** or an in-depth audit can give you valuable information about payback and can help you choose the best projects to meet your objectives

Recognize the $ value

Capital – Operational – HR

- Making the most efficient choice sometimes costs more capital but it can reduce both operational and HR costs
- Factor in lifetime costs and savings
- Behavioral change has no capital cost and can greatly enhance operational/HR savings

Recognize value beyond $

Responsibility – Security – Progress

- Electricity demand is growing
- Cost of electricity is gradually increasing
- Energy efficient materials and equipment sometimes have added benefits (longer life, health and safety, etc.)

Next Steps

What you need

- Understanding of **how electricity is used**
- Understanding of equipment and **processes** currently in place
- Information about energy efficient alternatives
- Lifecycle comparison

Who can help?

- YECL and YEC staff and websites can help you understand your bill; YECL can help you access data
- Operations and Maintenance **personnel**
- YECs Energy Conservation Dept., YECL, ESC, NRCan, Dollars to Sense

Where to begin?

Yukon Electrical can assist

- Provide historical consumption records
- Consolidate all accounts to a single monthly statement
- Provide a monthly electronic statement
- Provide rate calculation sheet to estimate savings potential

What makes up the charges on my Yukon Electrical bill?

- Demand
- Energy
- Riders and Taxes

How is energy charged?

General Service Rate Blocks

- 1 – 2000 kW.h = 10.00 ¢/KW.h
- 2001 – 15,000 kW.h =12.88 ¢/KW.h
- 15,001 – 20,000 kW.h = 15.68 ¢/KW.h
- 20,001 and over = varies by generation type

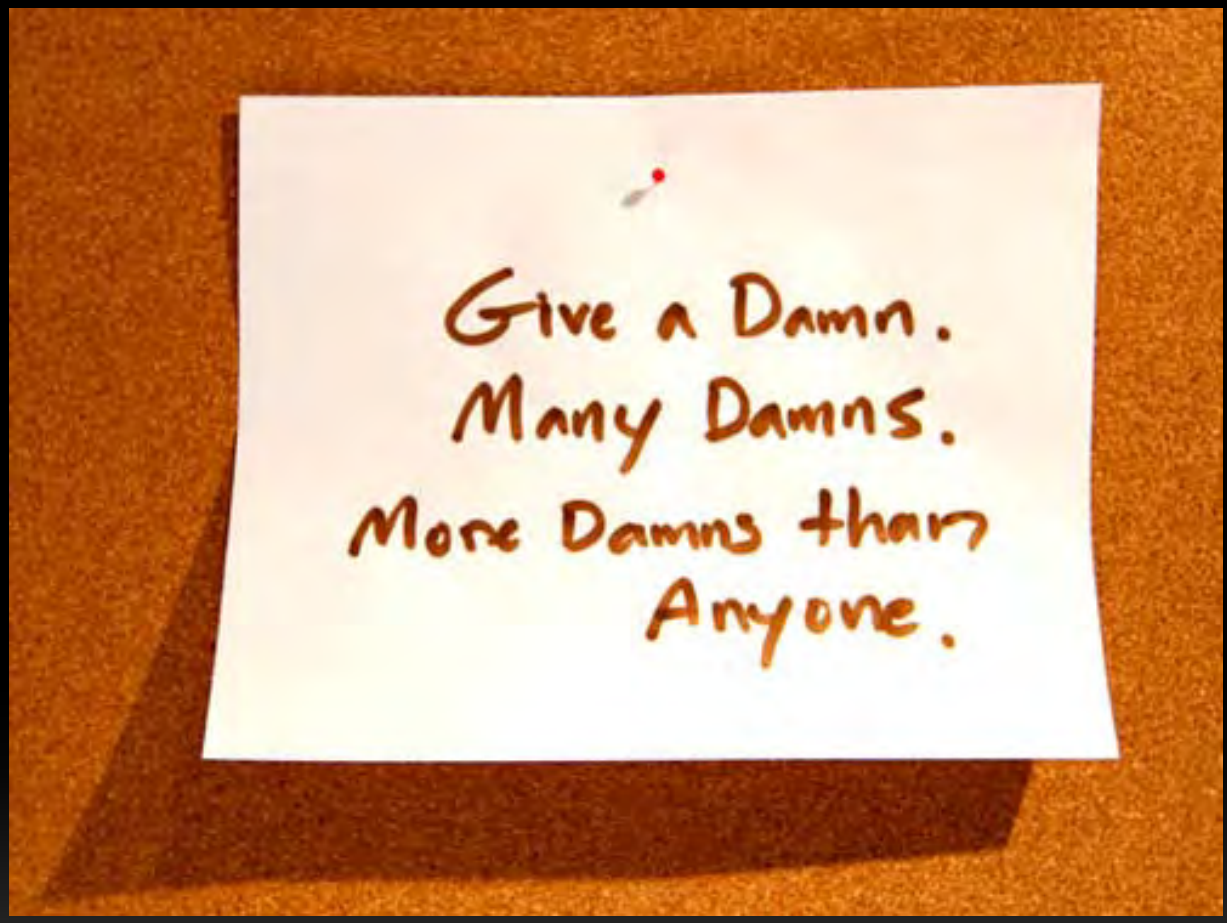
Understanding demand charges

- Measured demand is the result of the maximum draw required to meet coincidental use of equipment.
- The demand marker moves to record the maximum draw and is reset to zero each month at meter reading time.
- The monthly demand charge can be influenced by the previous 12 months.
- A peak demand can be set between the months of October and March.

How to reduce demand charges?

- Rethink the way equipment is started and used
- When replacing equipment consider
  - Operating costs
  - Capital Cost

THANK YOU



Jessica Thiessen (Yukon Energy) 208-212 Main St. Whitehorse 867-393-3898
http://www.yukonenergy.ca/energy/projects/dsm/

Wendy Scramstad (Yukon Electrical Company Ltd.) Whitehorse 867-633-7027

Yukon Conservation Potential Review (CPR)

Start up Meeting
May 2, 2011

Yukon CPR

Agenda

ICF Marbek

- Introductions
- Overview of Yukon Electricity Context
- Overview of CPR Work Plan
- Detailed Discussions of CPR Task Areas
- Wrap up & Lunch

Yukon CPR

Introductions

ICF Marbek

- Name
- Organization
- Primary Area(s) of Interest

Yukon CPR

Workshop Objectives

- Develop shared client/consultant understanding of:
  - Yukon DSM/CDM vision & challenges
  - Proposed CPR task areas, including deliverables and priorities
  - Client/consultant roles and responsibilities
- Ideas that can improve the proposed study approach

Yukon Electricity Context

- CDM Goals and Drivers
- Challenges
- CPR Expectations

Yukon CPR

Overview of Study Approach

- CPRs – lessons learned
- Our Team
- Study Work Plan & Results
- Schedule
- Working Together

Yukon CPR

CPRs – Lessons Learned

- Experience in other jurisdictions
  - ~ 15 CPRs completed in Canada in past decade
  - Virtually all Canadian electricity and natural gas companies
- Conclusion
  - ~ 50% Organization Development
  - ~ 50% Analytic and Modelling
  - By study's conclusion – all participants should have a shared vision of:
    - The size of the CDM/DSM potential
    - The most significant opportunities
    - The challenges and the preferred approaches for realizing the potential

Yukon CPR

About ICF Marbek

Marbek (1983 – 2011)

- Private Canadian company
- Energy and environment services to government, utilities, private sector, industry associations and research agencies in Canada and internationally
- Energy Practice (Energy Efficiency and Renewable Energy) – 4 business areas:
  - Energy System Planning (e.g., CPRs)
  - Energy Policy & Programs (design, implementation and evaluation)
  - Commercial Energy Services (e.g., facility energy audits, energy management plans, portfolio energy benchmarking etc.)
  - Industrial Energy Services (e.g., facility energy audits, energy management plans, portfolio energy benchmarking etc.)

Yukon CPR

About ICF Marbek

ICF Marbek

- January 1, 2011 – joined with ICF International
- Together, creates Canada's leading fully integrated energy, climate, and environmental consultancy specializing in energy efficiency and renewable energy
- Provides large pool of expertise to draw upon e.g.
  - ICF manages the design and implementation of U.S. Energy Star program on behalf of U.S. EPA
  - Design and implementation of large DSM programs on behalf of U.S. government and utility clients, many have been nationally acclaimed

Yukon CPR

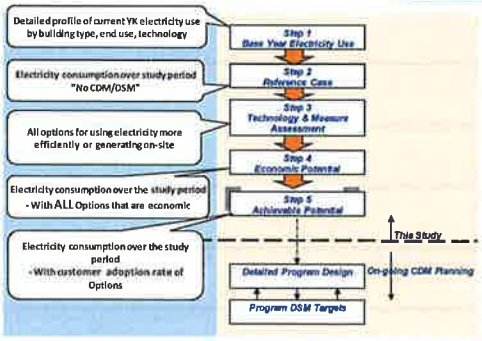
Study Team

ICF Marbek

Yukon CPR

Study Work Plan – 5 Steps

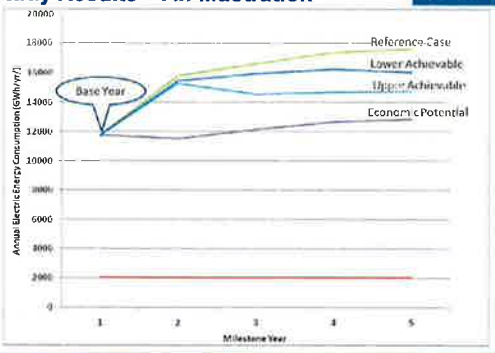
ICF Marbek



Yukon CPR

Study Results – An illustration

ICF Marbek



Yukon CPR

Schedule (tentative)

- Start up Meetings – May 2,3,4
- Revised Workplan – w/o May 9
- REUS & Sales Date rec'd – w/o May 30
- Phase 1 Reports – July 22
- Phase 2 Reports – Sept 22
- Achievable Potential Workshops – w/o Oct 24
- Draft Final Reports – w/o Nov 21

Yukon CPR

Working Together - Client Roles

We know you are busy!

...But, the CPR needs your contributions.

Our proposed roles for you:

- Help us access best possible existing data
- Participate in bi-weekly teleconference
  - Regular day and time each week; enables all parties to remain up to date on CPR status, ability to quickly make decisions affecting scope, assumptions and timing.
- Review interim deliverables

ICF Marbek

Questions/Suggestions?

Yukon CPR

Residential Sector

Yukon CPR Kickoff

Residential Topics

- Proposed segmentation – sub sectors and end uses
- Preliminary technologies
- Models
- Data needs and sources; gaps or issues

- Examples of outputs & applications – all sectors

Yukon CPR Kickoff

Segmentation Options

Can segment by:

- Detachment type
- Vintage
- Climate region
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
  - Detached
  - Attached
  - Low-rise apartment
  - Mobile/Other
- Vintage
- Supply system
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
  - Before major code change
  - After major code change
  - New construction
- Supply system
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system → Grid-connected, Diesel community
- Dominant heating fuel

Yukon CPR Kickoff

Segmentation Options

ICF Marbek

Can segment by:

- Detachment type
- Vintage
- Supply system
- Dominant heating fuel → Electricity, Fossil

Yukon CPR Kickoff

End Uses

ICF Marbek

- Space heating
- Domestic water heaters
- Lighting
- Refrigerators
- Freezers
- Cooking appliances
- Washing machines
- Clothes dryers
- Dishwashers
- Fireplaces
- Spa heaters
- Televisions & home entertainment electronics
- Set top boxes
- Computers and peripherals
- Small appliances
- Elevators
- Other

Yukon CPR Kickoff

Preliminary Technology List

- Heating: Shell Measures (Existing)
  - Attic Insulation
  - Wall Insulation
  - Slab Insulation (Unfinished Basements)
  - Basement (Foundation) Insulation
  - Crawl Space Insulation
  - Air Sealing/Weather Stripping/Caulking
  - High-Performance (ENERGY STAR™) Windows
  - Super High-Performance Windows
  - Air Leakage Sealing and Insulation (Old Homes)
- Heating: Shell (New Homes)
  - High-Performance Homes (EGH80 /R2000/ENERGY STAR™)
  - LEED Certified Apartment Buildings

Yukon CPR Kickoff

Preliminary Technology List

- Heating: Equipment
  - Air Source Heat Pumps
  - Ground Source Heat Pumps (Open Loop)
  - Ground Source Heat Pumps (Closed Loop)
  - Programmable Thermostats (Central Heating)
  - Programmable Thermostats (Baseboard Heating)
  - Solar Pre-Heated Make-Up Air Systems (e.g., SolarWall™)
  - High Efficiency Heat Recovery Ventilators (HRVs)
- Water Heating
  - Active Solar Water Heating Systems
  - Point-of-Use Water Heaters (Electric)
  - DHW Tank Insulation
  - DHW Pipe Insulation
  - Ultra Low-Flow Showerheads
  - Wastewater Heat Recovery Systems
  - DHW Recirculation Systems (e.g. Metlund D'MAND™)

Yukon CPR Kickoff

Preliminary Technology List

- Appliances
  - ENERGY STAR Dehumidifiers
  - Convection Ovens – Electric
  - High Efficiency (ENERGY STAR™) Refrigerators
  - High Efficiency (ENERGY STAR™) Freezers
  - High Efficiency (ENERGY STAR™) Front Loading Clothes Washers
  - High Efficiency (ENERGY STAR™) Top Loading Clothes Washers
  - High Efficiency (ENERGY STAR™) Dishwashers
- Lighting
  - Compact Fluorescent Lamps (CFL) – Indoor
  - Compact Fluorescent Lamps (CFL) – Outdoor
  - Dimmable Compact Fluorescent Lamps
  - LED Lamps
  - LED Holiday Lighting (Indoor)
  - LED Holiday Lighting (Outdoor)
  - Efficient Fluorescent Lamps (Replace T12s with T8s)
  - Motion Detectors and Timers for Outdoor Lighting
  - Motion Detectors and Timers for Indoor Lighting

Yukon CPR Kickoff

Preliminary Technology List

ICF Marbek

- Other
  - Spa Pump Timers
  - High Efficiency Spa Pumps
  - Insulating Spa Covers
  - Heat Pump Spa Heaters
  - Solar Spa Preheat
  - Timer/Thermostat for Block Heaters
  - Energy Efficient (ENERGY STAR™) Printers and Faxes
  - Energy Efficient (ENERGY STAR™) LCD Televisions
  - Smart Power Bars (Computers and Peripherals)
  - Smart Power Bars (Televisions and Home Entertainment)

Yukon CPR Kickoff

Models

ICF Marbek

- Hot-2000
  - Commercially supported software developed by the Federal government
  - Calculates *net* heating, cooling and hot water loads for homes including consideration of *cross effects*
  - Provides energy use intensity inputs into the macro model (RSEEM)
  - Used to develop a *tuned* house model matched to both what we know of Yukon construction and the energy sales data provided by the utility
  - The resulting model can be used to estimate the impacts of shell improvements

Yukon CPR Kickoff

Models

ICF Marbek

- RSEEM
  - An Excel-based *accounting* model
  - Is not a *predictive* model
  - Does all of the necessary arithmetic to calculate the energy consumption in each combination of building type, end-use, milestone year and supply system type for each scenario
  - Generates pivot-table-ready output for maximum flexibility in producing tables and charts needed by the client

Yukon CPR Kickoff

Data

- Needs
  - Fuel share data for space and water heating – current and forecast
  - Appliance saturation data, by dwelling type
  - Forecast growth in housing stock and electricity use, by dwelling type
  - Residential energy audit results – typical insulation levels, window type, building condition, etc
  - Studies on new construction practices
  - Studies on appliance use, both current and over the forecast period
  - Known territorial changes/dates to building energy performance standard, planned or historical

Yukon CPR Kickoff

Data

- Sources
  - Sales data
  - Residential End Use Surveys (forthcoming)
  - Load Forecast
  - Yukon Housing Corporation
  - EnerGuide for Housing database etc
  - Market or other studies
  - Reports documenting Yukon-specific conditions
- Gaps or issues?

Yukon CPR Kickoff

Outputs – All Sectors*

- Reports
  - Built up section by section as the phases of the project proceed
  - Opportunity to review, comment, and participate as we go
- Measure Analysis Model
  - Client can experiment with assumptions to see what changes occur
- Data Management Tool
  - Used by Marbek to make report exhibits
  - Client can manipulate study data to answer other questions

* Outputs vary somewhat by sector, to accommodate different needs.

Yukon CPR Kickoff

Measure Analysis Model

ICF Marbek

NB POWER COMMERCIAL SECTOR ELECTRIC EFFICIENCY MEASURES

T5 High Intensity Fluorescent Systems

Description:	High-intensity discharge (HID) lighting such as metal halide is commonly
Baseline:	Standard 400 W metal halide - Ballst power = 461 W, 20,000 hr lamp life
Upgrade:	Upgrade is a fluorescent high bay fixture equipped with six F54T5 HO

Sub-sector		Low use (2000 hours/year)	Med use (3500 hours/year)	High use (5000 hours/year)
Baseline	Elec. (kWh/yr.)	922	1,614	2,305
Upgrade	Elec. (kWh/yr.)	740	1,295	1,850
Heating Penalty/	Elec., Total (kWh/yr.)	92.8	162.5	232.1
Peak Demand Factor (kWh/kW)		6,787	6,787	6,787
Annual Resource Savings	Elec. (kWh/yr.)	89	156	223
	Elec. (kW peak)	0.013	0.023	0.033
Cost Parameters	Upgrade, Material ($)	$250.00	$250.00	$250.00
	Upgrade, Installation ($)	$75.00	$75.00	$75.00
	Baseline, Material ($)	$245.00	$245.00	$245.00
	Baseline, Installation ($)	$60.00	$60.00	$60.00
	Total Measure Cost ($)	$20.00	$20.00	$20.00
	Basis (Full/Incr.)	Incr.	Incr.	Incr.

Yukon CPR Kickoff

Measure Analysis Model

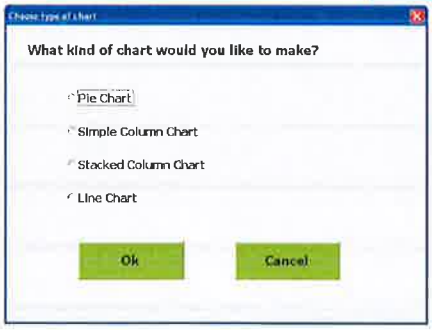
ICF Marbek

Cost Parameters	Upgrade, Material ($)	$250.00	$250.00	$250.00
	Upgrade, Installation ($)	$75.00	$75.00	$75.00
	Baseline, Material ($)	$245.00	$245.00	$245.00
	Baseline, Installation ($)	$60.00	$60.00	$60.00
	Total Measure Cost ($)	$20.00	$20.00	$20.00
	Basis (Full/Incr.)	Incr.	Incr.	Incr.
Incremental O&M ($/yr.)		$0.00	$0.00	$0.00
Lifetimes	Upgrade (yrs.)	16.0	16.0	16.0
	Baseline (yrs.)	16.0	16.0	16.0
Annual Savings ($/yr.)		$7.13	$12.48	$17.83
Simple Payback (yrs.)		2.8	1.6	1.1
NPV of O&M Costs ($)		$0.00	$0.00	$0.00
Total Benefits ($)	Electric Energy	$72.79	$127.38	$182
	Electric Demand	$0.00	$0.00	$0
Measure TRC ($)		$52.79	$107.38	$162
Benefit/Cost Ratio		3.64	6.37	9.10
Cost of Conserved Electricity (CCE) (¢/kWh)		2.53	1.45	1.01
Savings over Baseline	Elec.	19.7%	19.7%	19.7%
	w/ Elec.Htg. Penalty	9.7%	9.7%	9.7%

Yukon CPR Kickoff

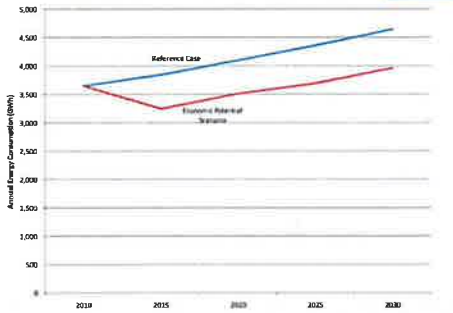
Data Management Deliverable

ICF Marbek



Yukon CPR Kickoff

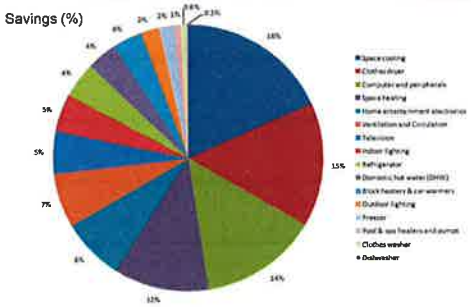
Data Manager: Scenario Comparison



* Results are from a Canadian electric utility study.

Yukon CPR Kickoff

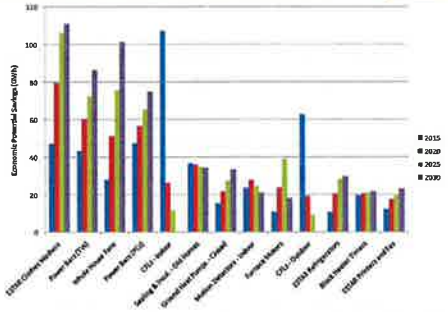
Data Manager: Results by End Use



* Results are from a Canadian electric utility study.

Yukon CPR Kickoff

Data Manager: Results by Measure



* Results are from a Canadian electric utility study.

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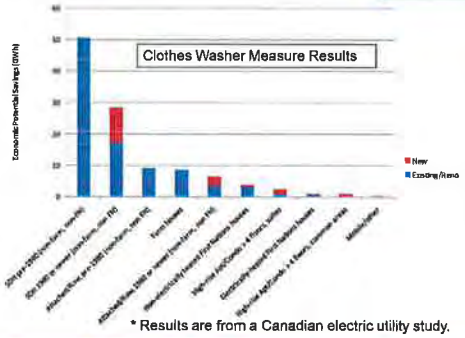
Data Manager: Zero in on One Measure



* Results are from a Canadian electric utility study.

Questions/Suggestions?

Yukon CPR

Commercial Sector

Yukon CPR Kickoff

Commercial Topics

ICF Marbek

- Framework / methodology review
- Proposed segmentation – sub sectors and end uses
- Preliminary technology list
- Model overview
- Study outputs
- Data needs and sources; gaps or issues
- Discussion

Yukon CPR Kickoff

Methodology

ICF Marbek

- Start with C/I consumption (sales)

Yukon CPR Kickoff

Methodology

ICF Marbek

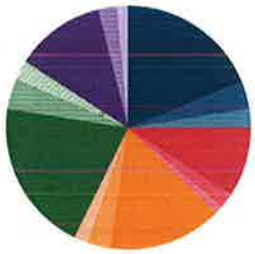
- Disaggregate into commercial sub sectors

Yukon CPR Kickoff

Methodology

ICF Marbek

- Disaggregate subsector consumption by end use



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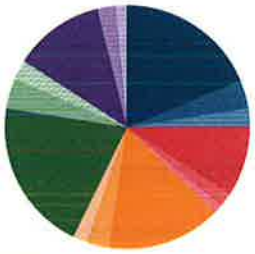
Methodology

ICF Marbek

- Apply measures in various scenarios



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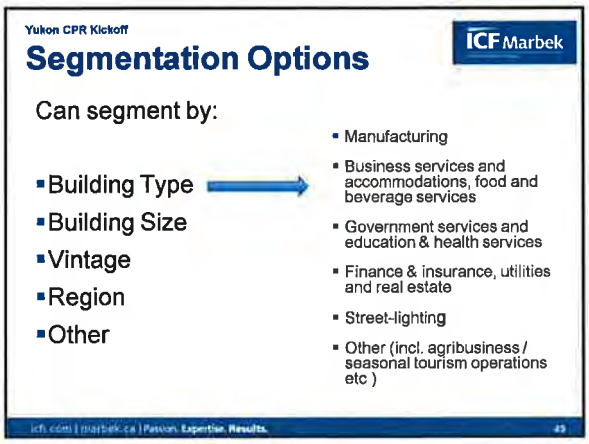
Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- Building Size
- Vintage
- Region
- Other


Yukon CPR Kickoff
Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Manufacturing
Business services and accommodations, food and beverage services
Government services and education & health services
Finance & insurance, utilities and real estate
Street-lighting
Other (incl. agribusiness / seasonal tourism operations etc)
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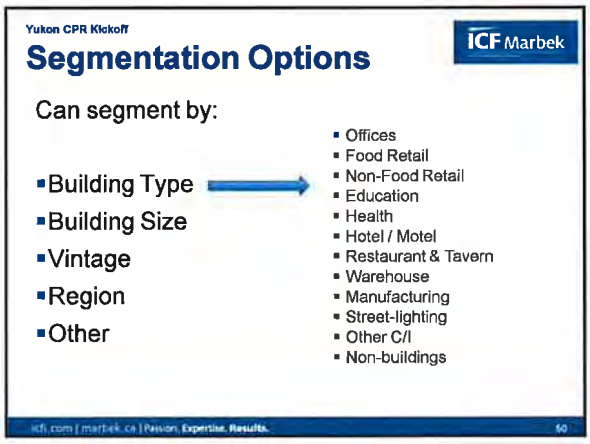
Yukon CPR Kickoff
Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Offices
Food Retail
Non-Food Retail
Education
Health
Hotel / Motel
Restaurant & Tavern
Warehouse
Manufacturing
Street-lighting
Other C/I
Non-buildings
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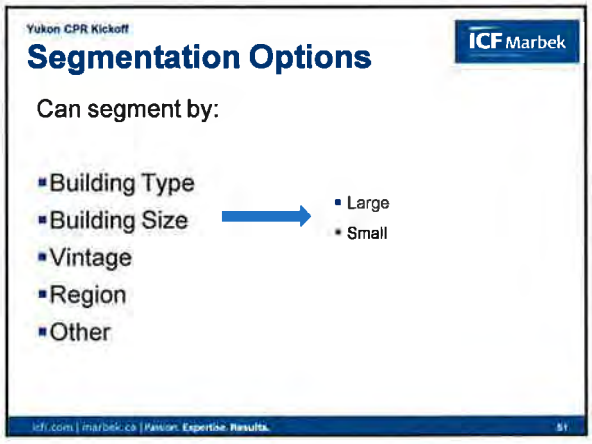
Yukon CPR Kickoff
Segmentation Options
ICF Marbek
Can segment by:
Building Type
Building Size
Vintage
Region
Other
Large
Small
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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- [illegible]
- Vintage → Existing stock; New construction
- Region
- Other

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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- [illegible]
- Vintage
- Region → Grid-connected; Diesel
- Other

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Segmentation Options

ICF Marbek

Can segment by:

- Building Type
- [illegible]
- Vintage
- Region
- Other → Government Subset

Yukon CPR Kickoff

End Uses

- General Lighting
- Secondary Lighting
- High Bay Lighting
- Outdoor Lighting
- Space Heating
- Space Cooling
- HVAC Fans & Pumps
- Water Heating
- Computers & Office Equipment
- Other Plug Loads
- Cooking Equipment
- Refrigeration
- Elevators
- Miscellaneous
- Street Lighting

Yukon CPR Kickoff

Preliminary Technology List

Lighting

- Standard T8 Systems
- High-Performance T8 systems—Retrofit
- High-Performance T8 systems—Redesign
- Occupancy/Dimming Controls
- Induction Lamps
- Compact Fluorescent Lamps
- White LED Lamps
- Halogen Infra-red Lamps
- Ceramic Metal Halide Lamps
- Pulse-start Metal Halide Systems

Exterior Lighting

- Compact Fluorescent Lamps—Outdoor
- Pulse-start Metal Halide Systems—Outdoor
- Lighting Controls—Outdoor
- Efficient Street-lighting

Building Envelope

- High-performance Glazing
- Super High-performance Glazing
- Upgrade Wall Insulation
- Upgrade Roof Insulation
- Air Sealing

Yukon CPR Kickoff

Preliminary Technology List

Water Heating

- Low Flow Faucet Aerators
- Low-flow Showerheads
- Low-flow Pre-rinse Spray Valves
- Tank Insulation
- Drainwater Heat Recovery
- Solar Hot Water Heating Systems

Cooking

- High Efficiency Cooking Equipment

Refrigeration

- ENERGY STAR Refrigerators and Freezers
- Efficient Refrigeration—Full Cost Measures
- Efficient Refrigeration—Incremental Cost Measures

HVAC

- Low-Temp. Air-source Heat Pumps
- Ground-source Heat Pumps
- Infrared Heaters
- Air-to-air Heat Recovery
- H.E. Chillers
- H.E. Packaged DX Cooling
- Demand-controlled Ventilation
- Demand-controlled Kitchen Ventilation
- Solar Preheated Make-up Air
- Adjustable Speed Drives
- Premium Efficiency Motors
- Programmable Thermostats

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Preliminary Technology List

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Whole Building Measures

Retro-commissioning
Advanced Building Automation Systems

New Buildings

New—25% better than Current Design Practice
New—40% better than Current Design Practice
New—60% better than Current Design Practice

Yukon CPR Kickoff

Models

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CEEAM

- Marbek's in-house building energy modelling platform, developed in conjunction with NRCan.
- Used to develop building archetypes for each commercial subsector based on:
  - What we know about the Yukon building stock
  - Information gathered from other jurisdictions
  - Sales data & other data provided by the utility
  - Other sources

Yukon CPR Kickoff

Models

ICF Marbek

CEEAM (cont.)

- Provides energy use intensity inputs into the macro model (CSEEM)
- Used as a tool to evaluate individual energy efficiency measures, particularly those affecting the building shell

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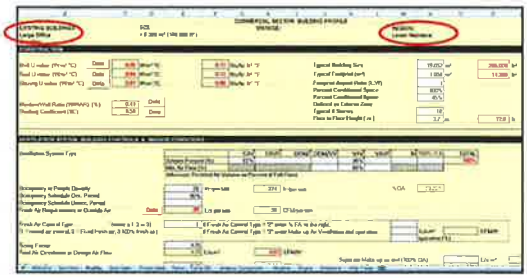
Models - CEEAM



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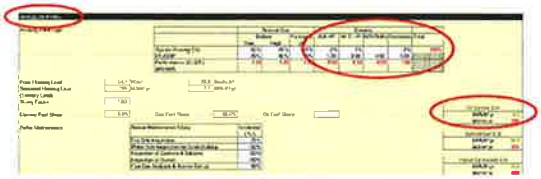
Models - CEEAM



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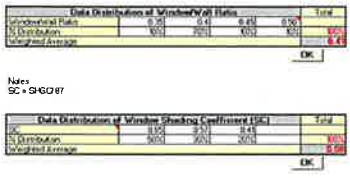
Models - CEEAM



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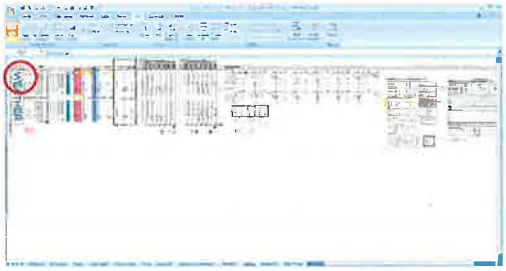
Models - CEEAM



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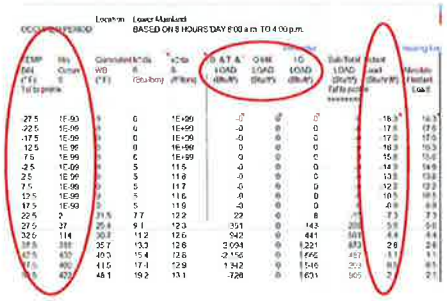
Models - CEEAM



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Models - CEEAM

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Models

ICF Marbek

HOT-2000

- Potential option for modelling sub sectors in which buildings tend to be small.

Yukon CPR Kickoff

Models

ICF Marbek

CSEEM

- An Excel-based *accounting* model
- Is not a *predictive* model
- Does all of the necessary arithmetic to calculate the energy consumption in each combination of building type, end-use, milestone year and supply system type for each scenario
- Generates pivot-table-ready output for maximum flexibility in producing tables and charts needed by the client

Yukon CPR Kickoff

Outputs

ICF Marbek

- Reports
  - Built up section by section as the phases of the project proceed
  - Opportunity to review, comment, and participate as we go
- Measure Analysis Model
  - Client can experiment with assumptions to see what changes occur
- Data Management Tool
  - Used by Marbek to make report exhibits
  - Client can manipulate study data to answer other questions

Yukon CPR Kickoff

Data

- Needs
  - Fuel share data for space and water heating – current and forecast
  - A/C saturation data, by building type
  - Forecast growth in building stock and electricity use, by sub sector
  - Commercial survey / energy audit results – typical insulation levels, glazing type, lighting equipment, building condition, etc.
  - Studies on new construction practices
  - Changes to building energy performance standards, planned or historical
  - Floor area data

Yukon CPR Kickoff

Data, continued

- Sources
  - Sales data
  - Yukon Energy Strategic Plan 2010-2012
  - Current load forecast
  - Market or other studies
  - Reports documenting Yukon-specific conditions
- Gaps or issues?

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Questions/Suggestions?

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Customer-side Renewable Energy
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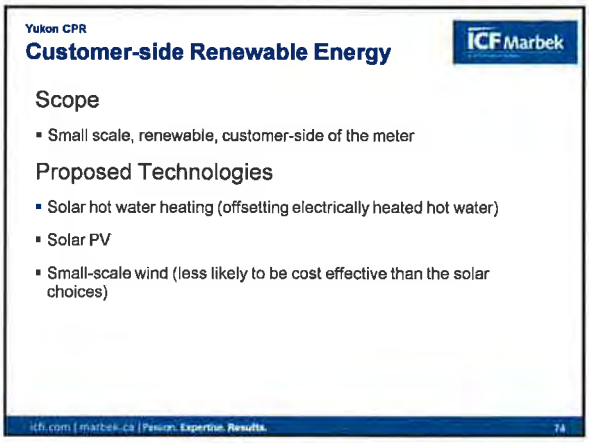
Yukon CPR
Customer-side Renewable Energy
ICF Marbek
Scope
Small scale, renewable, customer-side of the meter
Proposed Technologies
Solar hot water heating (offsetting electrically heated hot water)
Solar PV
Small-scale wind (less likely to be cost effective than the solar choices)
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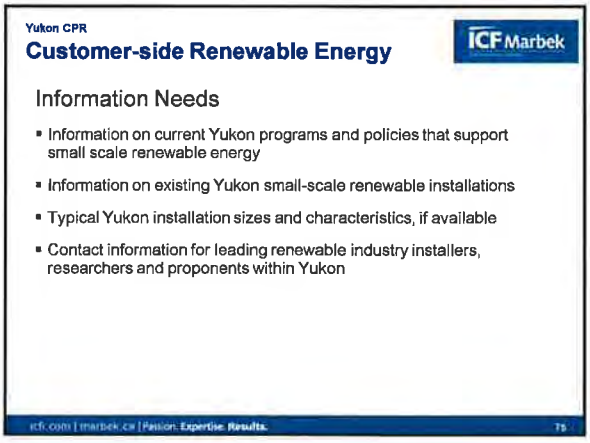
Yukon CPR
Customer-side Renewable Energy
ICF Marbek
Information Needs
Information on current Yukon programs and policies that support small scale renewable energy
Information on existing Yukon small-scale renewable installations
Typical Yukon installation sizes and characteristics, if available
Contact information for leading renewable industry installers, researchers and proponents within Yukon
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Customer-side Renewable Energy

ICF Marbek

Next Steps

- Ruth Urban is team lead
- This meeting - Establish client contact(s) for CSRE
- Post meeting - Teleconference to initiate this study component

Yukon CPR
Peak Demand (Capacity)

Yukon CPR

Peak Period (Capacity)

ICF Marbek

- **Step 1 – Define Peak Period(s) of Interest**
- **Example from previous study:**
  - **Peak Period #1: Annual System Peak Hour** –e.g., the hour ending at 7 pm on a day in December; it is highly correlated with the coldest day of the year when occurring in December.
  - **Peak Period #2: Annual Weekday System Peak Period** – The 5-9 pm period on the coldest day of the year when occurring in December.
  - **Peak Period #3: Annual Weekend System Peak Period** – The 5-9 pm period on the coldest weekend day of the year when occurring in December.
  - **Peak Period #4: Annual Peak Energy** – This uses the peak hours of 7am through 10pm on all weekday non-holidays during the year.

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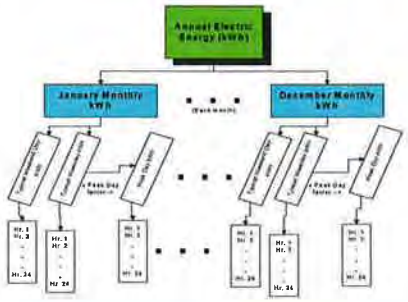
Peak Period Approach

- Step 2 – Allocate Annual Electricity Use for each facility type and end use



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Peak Period Approach
Sample Output – For illustration only

Dwelling Types	Period 1 Peak Hour	Period 2 Week Day Peak Period	Period 3 Weekend Peak Period	Period 4 Peak Energy
Single Detached Houses	666	658	610	330
Attached/Row Houses	99	97	89	50
Farm Houses	91	91	85	49
First Nations Housing	62	61	53	26
Apartment/Condo Buildings	22	22	22	8
Mobile/Other	0	0	0	0
Grand Total	941	930	860	463

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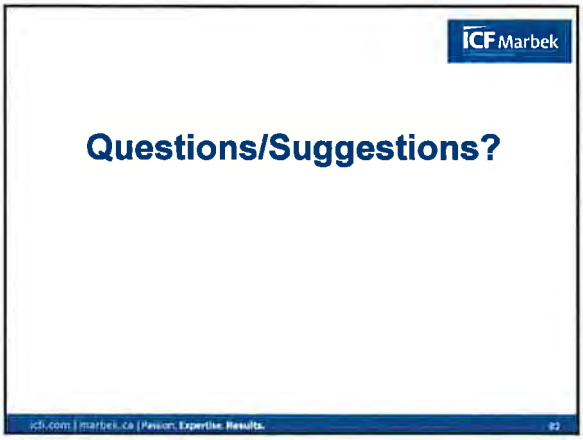
Peak Period (Capacity)

Next Step

- Joe Lopes is team lead
- This Meeting -Establish client contact(s) for peak period
- Post Meeting -Follow up teleconference to initiate this study component


ICF Marbek
Questions/Suggestions?
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Thank You !
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DSM Community Visit Schedule
Wednesday May 4 and Thursday May 5, 2011

DATE	LOCATION	DETAILS
Wednesday May 4		
8:00 am	Depart Whitehorse	Leaving from High Country Inn
9:30 am	Arrive Haines Junction	Meet at Village Office to coordinate sites visit
10:15 am	Alcan Inn	No guide for visit, have been invited to look around…requested to notify Talise of our arrival
10:30 am	Community drive around	
11:00 am	Lunch	
11:30 am	Depart for Burwash Landing	
1:30 pm	Arrive Burwash Landing	
1:30 pm	Meet at Public Works Building (Kluane First Nation)	Meet Joe Bruneau 867-841-4200 Drive through town, go past the admin building. Take first right after, up the road until you see a blue trailer and blue shop…in blue shop.
2:00 pm	Community drive around	
2:20 pm	Depart for Destruction Bay	
2:40 pm	Arrive Destruction Bay	
2:40 pm	Community drive around	
3:00 pm	Depart for Haines Junction	
4:45 pm	Arrive Haines Junction	
4:45 pm	Kluane Park Inn	Alicen is the contact, happy to have us view the bar (café isn't open yet)
5:15 pm	Depart for Whitehorse	
6:45 pm	Arrive Whitehorse	High Country Inn
Thursday May 5		
9:20 am	Pick-up to start tour	
9:30 am	Canada Games Centre – 200 Hamilton Blvd	Meet Art Manhire, manager of indoor facilities
10:00 am	City of Whitehorse Municipal Service Building - 4210 Fourth Avenue	Meet Larry Shipman, Engineering (867-668-8304)
10:45 am	YECL Building – 1100 1st Avenue	
11:00 am	Hougan Centre Tour – 305 Main Street	Meet Terry Shipman, property manager - 333-9929
12:00 pm	Lunch	
1:30 pm	Government of Yukon facility - Supply Service's and Stores –	Yukon Government – Jim MacPherson, Engineer Foreman

	Industrial park (Enter at central workshop compound – Bldg #1277	(cell 667-3073)
2:00 pm	Government of Yukon facility - Law Centre – 3rd Avenue	Jim will follow
3:30 pm	Arrive Jack Hulland School – 1304 Fir Street	Meet David Black, Environmental Coordinator Department of Education
4:00 pm	Finish tour day	

Demand Side Management Inititiative

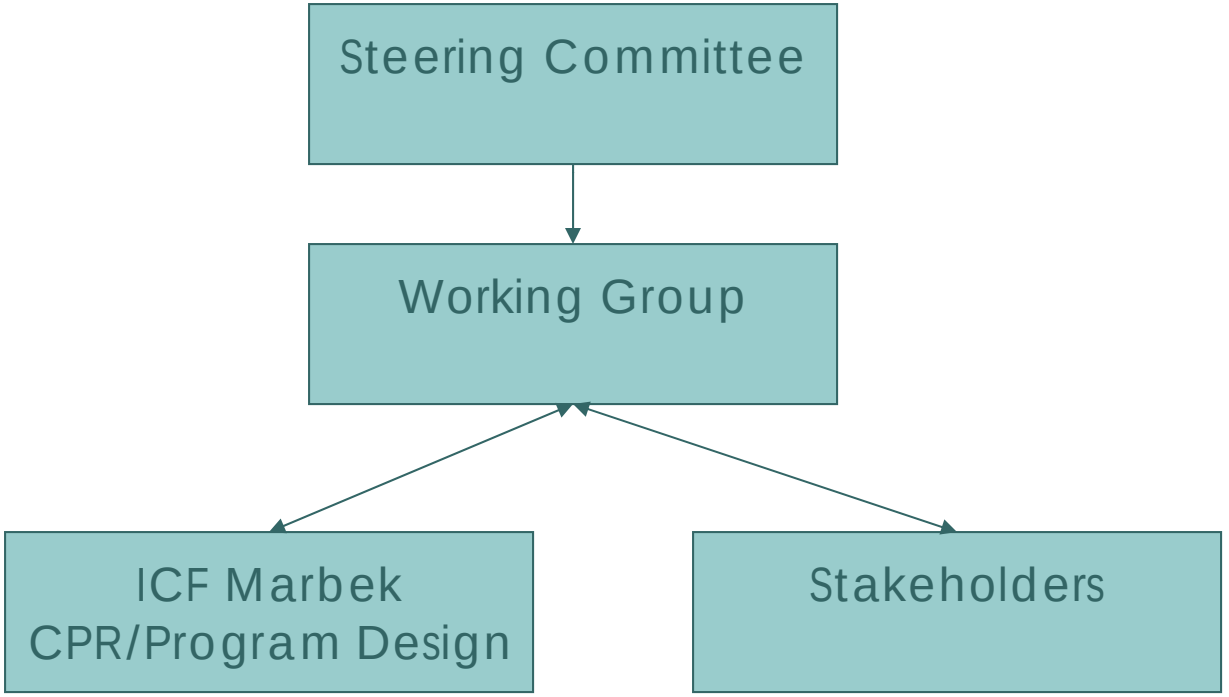
Yukon Energy Charrette

April 19, 2012

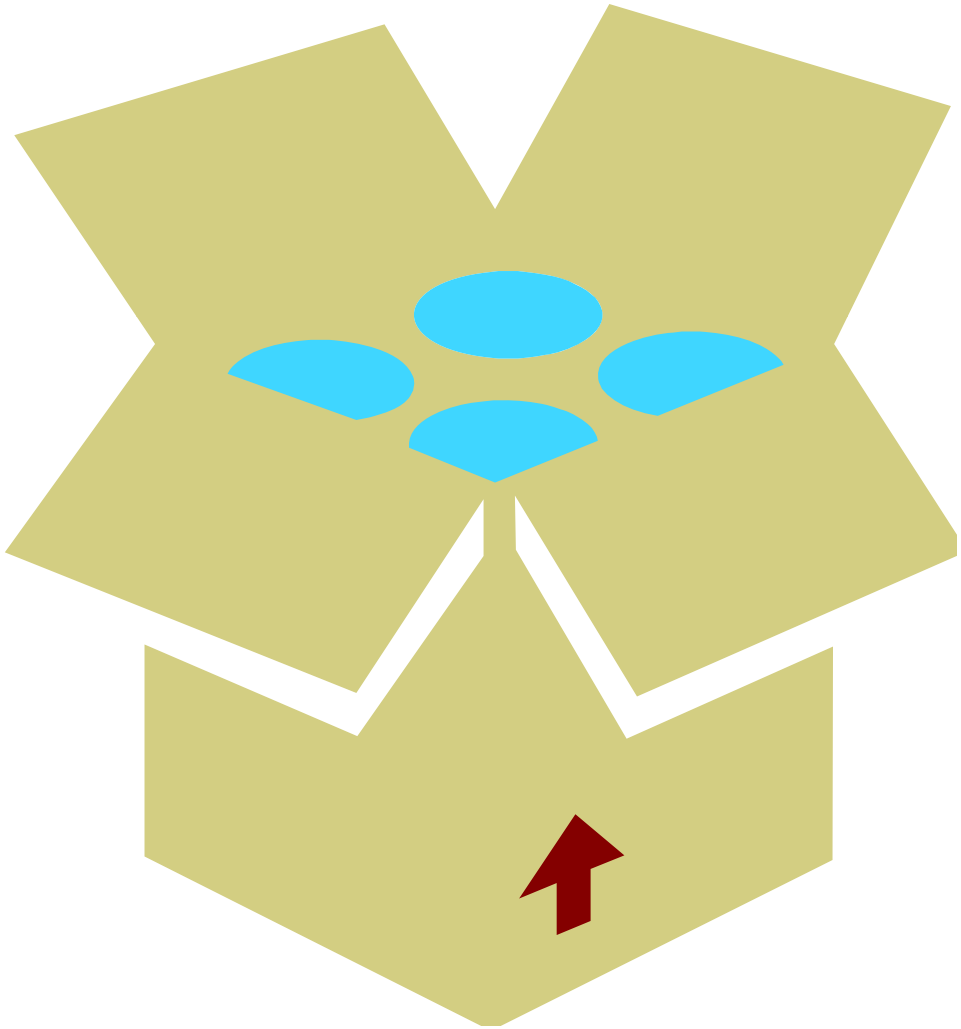
Demand Side Management Drivers

- Yukon Utility Board Orders
- Energy Strategy for Yukon
- Growth in the territory (All sectors)
- Increased reliance on diesel generation

Demand Side Management Partners



The Electrical Box



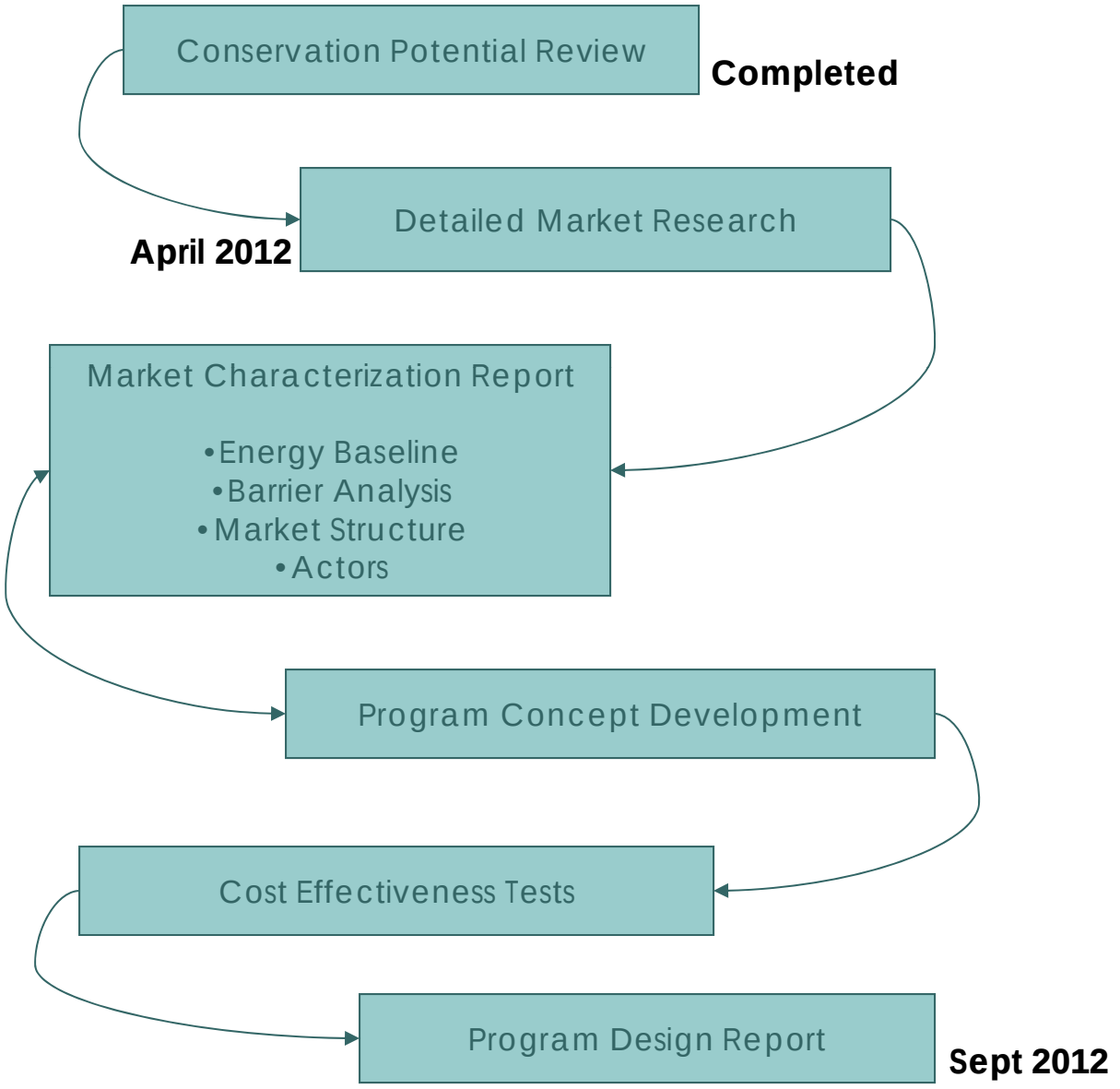
Conservation Potential Review

- Reference point:
  - Residential
  - Commercial/Institutional
  - Customer-side renewable options
- Base year established using actual data for 2010
- Forecast consumption to 2030 with benchmarks every 5 years

Other Initiatives Completed

- Community Engagement
- Residential End Use Study
- LED Streetlight Pilot
- Awareness Building
- Net-Metering
- On-going Energy Solution Centre

Detailed Program Design



Next Steps

- Reduction Targets
- DSM Framework and Plan Delivery
- Customer Engagement
- Submission to Yukon Utility Board

YUKON ENERGY

Energy Conservation Workshop Report

April 19, 2012

1. Introduction

At the Yukon Energy Charrette in March 2011, Yukon Energy brought together governments, Yukoners and energy experts from across Canada for three days to discuss and share information on resource options for Yukon's energy future. One of the key outcomes from the charrette was Yukon Energy's commitment to continue engaging stakeholders, governments and the public in planning for the future. To meet that commitment and plan in public, Yukon Energy is holding energy workshops on a series of topics and resource options. The Energy Conservation Workshop is Yukon Energy's fourth workshop.

The information gathered from the workshops and public meetings is being used to inform and direct the work of Yukon Energy and its consultants in carrying out the resource options planning. The information gathered from this workshop will also be used by the Demand Side Management Working Group (YG, YECL, and YEC) to help them develop a conservation program in the Yukon as directed by the Yukon Utilities Board (see Drivers of Demand Side Management Presentation on YEC website).

This is the report from the Energy Conservation Workshop and Public Meeting held on April 19th, 2012 in Whitehorse.

2. Workshop Objectives

The workshop objectives were developed with Yukon Energy and their partners. The workshop partners were: Yukon Electrical Company Ltd, Energy Mines and Resources, (Yukon Government), Yukon Conservation Society, the Yukon Utilities Consumer Group and Alexco Resources. The partners contributed their expertise and were supported by consultants from Morrison Hershfield Engineering, ICF Marbek and John Streicker. The objectives that guided the workshop were:

1. Examine energy conservation in the context of the YEC planning principles and 20-Year Draft Resource Plan;
2. Identify the environmental and socio-economic issues and opportunities in relation to energy conservation in Yukon;
3. Educate the participants as to conversation potential and opportunities;
4. Understand the regulatory framework in which the Demand Side Management (DSM) Working Group has been working; and,
5. Obtain feedback from participants on how to deliver successful energy conservation programs.

3. Workshop Participants

Over 65 invited and interested workshop participants attended the half day session. Participants represented the following stakeholders, governments and industry:

Yukon Energy Corporation

Yukon Electrical Company Ltd.

Kwanlin Dun First Nation

The Village of Carcross

City of Whitehorse

Alexco Resources

Champagne Aishihik First Nation

Yukon Conservation Society

Tipping Point Strategies

Association of Yukon Communities

Yukon Utilities Consumer Group

Government of Yukon (Highways and Public Works Property Management Division, Energy Solutions Centre, Energy Mines and Resources, Department of Education, HPW Capital Development, Climate Change Secretariat)

Yukon Environmental and Socio-Economic Assessment Board

Town of Watson

Green Heat Technologies Ltd.

Northerm Windows and Doors

Narrow Gauge Construction

ICF Marbek

Northern Climate Exchange

Yukon Development Corporation

Village of Carmacks

Leading Edge Projects

Whitehorse Chamber of Commerce

Yukon Cold Climate Innovation Centre

The workshop was also attended by Yukon Energy staff and consultants.

4. Presentations

The workshop provided the opportunity for Yukon Energy to share the findings from the Conservation Potential Review with the participants as well as for key stakeholders, partners and governments to present their information. The following presentations were delivered at the workshop and are posted on the Yukon Energy website at www.yukonenergy.ca/energy/public_engagement/energyworkshop/.

a) ***Why Demand Side Management?*** John Streicker, P.Eng., Science Advisor and Climate Change Expert, Northern Climate Exchange, Yukon College.

b) ***Drivers of Demand Side Management in the Yukon.*** Jessica Thiessen, Manager Energy Conservation.
c) ***Results from Conservation Potential Review***. Paul Robillard, Director, ICF Marbek.
d) ***Alexco Demand Side Management & Audit Review.*** Peter Johnson, Construction Manager, Alexco Resources.
e) ***Utilities Consumers' Group Demand Side Management Presentation.*** Roger Rondeau, Yukon Utility Consumers Group.
f) ***Building a Culture of Conservation Beyond the Utilities.*** Anne Middler, Energy Coordinator, Yukon Conservation Society.

5. Workshop

Following the presentations the participants were organized into facilitated groups ranging from 6 to 8 people. The groups were asked to discuss and record their ideas and comments with the intention of the work being shared with the participants, the public and included in the Yukon Energy's resource planning activities and the Demand Side Management Working Group's planning and program design work. This work with also be used to inform the ongoing resource planning work.

The participants were asked to report on the following questions that are related to how to deliver successful energy conservation programs:

1. **Who needs to be involved in the delivery of conservation programs?**

    - Who should be Involved?
    - What are the barriers?
    - What are the opportunities?

2. **What is the role of the Utilities and government in delivering conservation programs?**
3. **What is the community's role in ensuring conservation programs are successful?**
4. **What groups/organizations currently exist that can facilitate the delivery of conservation programs? How should they be engaged?**
5. **How can existing groups and interested individuals work to integrate electricity efficiency and conservation into their broader community based conservation initiatives?**

Results

The following is a summary from the workshop and public meeting.

Involvement in Delivery of Conservation Programs

Conservation programs should involve:

- Consumers, utilities, developers, trades, large users, industrial sector, commercial sector, supply chain actors, all levels of government, Yukon Housing, chambers of commerce, professional organisations, non-governmental organisations, Utilities' Consumers Group, Yukon Conservation Society, Yukon College, children, education system, technology suppliers, implementers representing successful programs from outside Yukon.

Potential barriers include:

- Information is non-existent (the public doesn't know how electricity is used), information can be hard to find, there can be too much information, or it can be confusing.
- Communities do not have the financial resources within their regular budgets to implement/pay for programs.
- Politicians need to make financial commitments in the short term to realise benefits over the long term.
- Lifecycle costing is not part of personal product purchasing decisions.
- Programs adopted from elsewhere may be ineffective in the northern context.
- There are currently no incentive policies for energy time of day pricing, audits, loans and grants.
- DSM resources and programs are Whitehorse centric.
- There is a suspicion of new technology.
- The public does not understand what the motivation of public utilities is.
- There is ratepayer skepticism because it is the business case of the utility to sell electricity.
- There are limited options and incentives currently available to implement energy conservation programs.
- Resistance to change and mindsets of public, corporations and government - apathy, too easy to not be part of the solution, and perceptions "nothing I can do would make a difference".
- Understanding and considering the impact of programs, peak saving versus total electricity reductions.
- Obtaining sustained user change, needs to be mainstreamed and not an add-on.
- There may be a loss of incentive for conservation if excess capacity becomes available.
- Billing systems for industrial customers – hard to coordinate load on 9 different systems/invoices.
- Current metering and pricing signals is a barrier.

- There are no incentives for landlords or tenants to conserve depending on who pays utility bill.
- Industry backlash.

Potential Opportunities Include:

- Saving energy and money.
- Develop partnerships among all energy users, utilities, and policy makers.
- Develop different programs and priorities for different communities (one size does not fit all).
- Personalise achievements toward targets/progress
- Work with First Nations to build capacity and adopt programs.
- Create a rewards system for groups implementing DSM to provide incentives for industrial customer, energy performance contracts.
- Identify user classes and tailor programs/incentives to each group.
- Offer energy conservation programs at Yukon College and as part of the trades programs.
- Include in the public school curriculum.
- Implement seasonal rates.
- Examine the applicability of smart meters.
- Complete the net metering policy to encourage distributed energy which would allow the promotion of rooftop solar PV and solar thermal.
- Jobs from the development of a building retrofit program.
- Use social marketing and the local media to promote energy efficiency.
- Energy performance contracts with users.
- Public education - show consequences of no DSM, make electricity use more visible.
- Public product education e.g. promote most efficient energuide products, standardised labelling, energy labelling of housing, choice editing, develop web-based tool to assist in lifecycle costing etc.
- Yukon Utility Board should look at costs of all energy sources not just electricity rates to promote conservation for all energy sources, not just electricity.
- Develop a simplified one stop shop for information and program delivery that is flexible and reflects Yukon's diversity.
- Encourage ground-source heat pump for peak shaving.
- Encourage YG and the City of Whitehorse to develop energy efficient building codes.

Utilities and Government's Roles and Responsibilities in Delivering Conservation Programs:

Utilities should:

- Develop, implement, and evaluate conservation programs.
- Educate the public and stakeholders on need for conservation and programs and work with them in developing programs.

- Require large customers implement energy efficiency measures, have best practices in place.
- Track electrical usage in sample groups for each sector. Share usage and supply data with partners to help recognise and implement energy efficiency opportunities. Use information available on energy usage to outline feasibility and impact of actions so that government can provide policy support for implement programs. Use product knowledge to educate and create programs that encourage consumers to choose most efficient products.
- Promote early adopters by providing some good PR and provide awards for outstanding performance. Provide a report card on effectiveness of conservation programs that promotes accountability, raises public awareness, and gives opportunity for community input

Yukon Territorial Government should:

- Need to lead by example, promote conservation in the schools and curriculum (K-12).
- Provide programs for professions and trades in fields that support energy conservations.
- Policy development such as climate action plan, energy plan, and climate adaptation plan and adopt GHG, renewable energy, and energy conservation targets. Implement a net metering program. Direct the utility to achieve conservation targets and implement programs.
- Enable utilities to implement conservation programs. Encourage economic development in support of conservation (innovation, incentives, and policies).
- Mandate energy efficiency in codes.
- Target policies to groups and sectors such as government users, rate payers, mines, low income, renters/landlords, and developers.
- Reward innovation.

Municipal Governments should:

- Lead by example and be early adopters.
- Enact complementary codes, by-laws, tax incentives, and planning practices (planning with consumption in mind) that promote conservation.
- Reward innovation.
- Show vision in the community plan and money will come in support of that vision. Remind the community of that vision.

First Nations should:

- Lead by example.
- Could provide economic development opportunities.

The community's roles in ensuring conservation programs are successful

The community should:

- Create a culture of conservation with participation from everyone in all sectors.
- Shift culture from instant gratification to long term savings.
- Maintain in the long term the awareness for the need to conserve.
- Be watch dogs to the utilities and government.
- Be a source of ideas.
- Challenge or complete with other communities to obtain energy reductions.

Existing Groups/organizations that can facilitate the delivery of conservation programs and how they should be engaged?

Consumers should:

- Participate in the program design.
- Be provided with information to make choices that reduce electricity consumption.
- Have tools to help them understand lifecycle cost savings.
- Take responsibility in their energy use through behaviour change and be held accountable.
- Be educated of peak usage so they can adjust consumption to be part of the solution.

Industrial users should:

- Be role models, by providing leadership by making long-term investments in energy efficiency.
- Be involved in the development of conservation program planning.
- Reward employees for green ideas.
- Help make the business case for conservation work.
- Evaluate/audit designs of projects and buildings at the design stage to maximise economic opportunities for efficiency.

Developers should:

- Have state of the art energy efficiency in new buildings.
- Think of conservation at the design stage.

Chambers of Commerce/Private Sector should:

- Help developers, and private sector businesses to be ambassadors for energy efficiency and feed information to government and utilities in conservation program design.
- Test potential programs.
- Provide expertise to recognise and implement opportunities.
- Be role models and reward employees for green ideas.

- Have retailers carry products that promote energy conservation as well as adopt best practices.

Yukon College and Yukon Cold Climate Innovation Centre should:

- Lead by example and become early adopters.
- Offer courses and research related to conservation opportunities in the northern climate.
- Launch pilot projects in implementing conservation measures and to test new technology.

Schools should:

- Lead by example and become early adopters.
- Teach energy literacy and awareness of conservation to children as a means to bring culture of conservation to the community similar to the recycling message.
- Provide energy usage and conservation assignments for children to bring home.

Non-governmental organisations should:

- Provide advocacy and be a watchdog.
- Fill in knowledge gaps.
- Ensure that programs are equitable.
- Provide assistance in program delivery, particularly n remote communities.

Energy Solutions Centre should:

- Support program delivery, provide program funding, and provide resources on examples of energy efficiency.

Yukon Housing should:

- As building experts, promote more energy efficient building standards.

6. Summary

The workshop participants recognise that conservation is an important part of meeting future energy needs. For energy conservation to be successful it requires involvement by all individuals and organisations. First and foremost, both the utilities and all governments must be role models for energy conservation. This means they should work together to promote energy efficiency and be early adopters.

Yukon Energy Corporation and Yukon Electrical Company Ltd. who hold the information on energy usage have the data to help develop programs for all sectors as well has provide a resource to customers on energy usage. The governments and the utilities need to work together and share information to inform government and utility policies, regulations, practises

and opportunities. The governments need to provide the utilities the policy tools to enable them to provide effective energy conservation programs. The utilities, with their understanding of energy planning need to inform the governments of the conservation opportunities and the resources required. There is also an opportunity for Yukon College and the Northern Research Center's Cold Climate Innovation group, NGOs and the private sector to provide technical input on what types of programs should be adopted. Government energy, greenhouse gas reduction and renewable energy policies should be aligned with the mandates and objectives of the utilities. This also includes green procurement, building codes, investment, and pricing signals. Programs should be tailored based on usage patterns and requirements of particular sectors. The utilities should be able to monitor the effectiveness of programs, adjust programs based on effectiveness, provide accountability, and ensure sustained promotion of energy conservation programs. Successful programs from elsewhere should be looked at as a starting point; however, their effectiveness needs to be evaluated in the northern context.

There is a need for capacity building including consumer education of energy efficiency products, training opportunities for trades in conservation fields, research and piloting in the application of technologies and programs in the north. In particular, there is a significant opportunity within the school system to provide students with energy literacy which could enable them to bring conservation home. Programs need to be equitable to both low-income and renters. Governments can provide financial and policy support to overcome these barriers.

Information needs to be available to consumers on the lifecycle costs of products, choices and initiatives to enable the government, industry, purchasers, and ratepayers to make energy conservation choices understanding the full cost of their decisions. Governments need to plan long term and consider the life cycle costs and opportunities of their choices. Financial institutions should also be encouraged to recognise the long term benefits of energy efficient choices and develop programs with long term benefits in mind.

It is important that conservation includes industry and does not appear to target only consumers. There is an opportunity for industry to be leaders by adopting best practices in energy efficiency both in looking to existing operation and equipment and in the design development stages of projects. All sectors can learn from such successes.

Overall, the key to success of an effective conservation program is knowledge and the development of a culture of conservation. Everyone should be aware of the impact of energy usage and be an active participant in the effort to conserve. Leadership by governments, utilities, businesses, utilities, and individuals to this mandate will ensure effective and enduring reductions in energy demand.

Yukon Energy thanks all those that participated in the workshop and public meeting. The presentations from the workshop experts along with the responses to the workshop questions are being incorporated into the development of Yukon Energy's energy conservation programs. Yukon Energy is committed to working with its partners, sharing information and to keep talking.

Demand Side Management Paper for the Energy Conservation Workshop, April 19, 2012

Prepared by Morrison Hershfield for Yukon Energy

1.0 Introduction

Energy conservation and efficiencies, referred to in the utility industry as demand side management (DSM), provides opportunities in Yukon to meet future energy requirements by reducing the need to construct additional electricity generation capacity. DSM includes both decreasing the total electricity demand and shifting the demand by changing when electricity is used. In both cases the cost of constructing new electricity generation capacity is avoided. DSM maximizes the use of the existing installed capacity. As such, DSM meets Yukon Energy's energy planning principles of reliability, affordability, flexibility, and environmental responsibility.

Direction from the Yukon Utilities Board, public responses (survey and energy charrette) and alignment with the Yukon government's Energy Strategy and Yukon Energy's corporate priorities means that an effective and robust DSM program is a crucial element in Yukon Energy's energy resource planning. According to a recently completed Conservation Potential Review conducted for the territory's two utilities and the Yukon government, it has been estimated that by 2030, DSM has the potential to save up to 48% of projected residential and commercial electricity demand growth on the Yukon grid.[1]

Direction from the Yukon Utilities Board, public responses (survey and energy charrette) and alignment with Yukon Government's Energy Strategy and Yukon Energy's corporate priorities has resulted in ensuring that an effective and robust DSM program is considered when forecasting Yukon's energy and capacity requirements over the next twenty years. Yukon Energy is also working to reduce its own energy consumption through Supply Side Enhancements (i.e. improved efficiency of generation units, transmission, etc.) and internal corporate energy conservation and efficiency initiatives (changes to operations, procurement, staff behavior, etc.). As well, it is working one-on-one with the industrial (mining) sector on energy conservation/efficiency initiatives. In order for DSM to achieve the greatest potential it requires participation from all Yukoners.

2.0 20-Year Resource Plan Demand Forecasts

Yukon Energy is updating its 20-year resource plan which will address the corporation's generation and transmission priorities in Yukon to 2030. The plan will provide overall planning guidance for resource options to be implemented in the next five years and over the longer term. Energy conservation is an important part of the plan.

The hydro surplus in existence since the closure of the Faro mine in the late 1990s is becoming depleted as demand for electricity increases from all sectors (residential, commercial, government and industrial). Further, most of the hydro enhancement opportunities previously identified have now either been developed or are currently under active consideration. Yukon Energy is exploring a range of other energy options that will either minimize or displace reliance on diesel. Energy conservation/efficiencies is one of the best of these options, since the more electricity is saved, the less new infrastructure needs to be built.

[1] Yukon Electricity Conservation and Demand Management Potential Review (CPR 2011) released January 9, 2012

3.0 Public Response to Energy Conservation

Yukoners support energy conservation. A public opinion survey conducted for Yukon Energy in June 2010 reported 89 percent of Yukoners support assuming more personal responsibility toward energy conservation[2].

The energy charrette hosted by Yukon Energy in March 2011, which brought together about 100 Yukoners and energy experts from across Canada for three days to talk about the territory's energy issues, further confirmed support for DSM. Energy conservation was ranked as the most preferred energy resource option and was considered as a key resource planning option in the short, medium and long term planning scenarios (see Figure 2 below from the Charrette Report)

Figure 2: Energy Charrette March 2011

Summary of the type of choice cards selected per time frame scenario		
2015	**2025**	**2050**
• Hydro Enhancement (Marsh Lake) • Demand side management • Wind • Biomass • Hydro enhancement (Atlin Lake) • Hydro enhancement (Gladstone) • Liquefied natural gas • Solar • Waste to energy • Diesel enhancement • Individual district generation • On-site generation at large mines	• Solar • Wind • Liquefied natural gas • Biomass • Demand side Management • Medium sized hydro • Geothermal • Micro-nuclear • Small hydro/hydro enhancements • Vehicle battery storage • Waste-to-energy • Connection to B.C. grid • Independent Power Producers • Large hydro • Spinning reserve	• Solar • New hydro • Biomass • Demand side management • Grid connection with BC/Alaska • Liquefied natural gas (from pipeline) • Electric transportation • Geothermal • Micro-nuclear • New technologies

4.0 What Yukon Energy is Doing

Building on the public affirmation that DSM is a crucial element in helping us meet Yukon's growing electricity needs, Yukon Energy has moved forward on energy conservation. In working towards the development of a territory-wide energy conservation/efficiency plan, Yukon Energy has been involved in the following initiatives over the past year:

[2] Public and Stakeholder Phone Survey Results Public Awareness Campaign Phase 1: Research Report 1 released June 25, 2010

New Department

Yukon Energy established an energy conservation department in 2011 to work with stakeholders on Yukon-wide energy conservation and efficiency programs. This department will also help the Corporation find ways of reducing our own energy use. Energy conservation is a critical element in helping us meet Yukon's growing energy needs.

Working Group

Yukon Energy chairs an energy conservation working group, made up of representatives from Yukon Electrical Company Limited and the Yukon government's Energy Solutions Centre along with two of our own staff. We also participate in a Demand Side Management steering committee, made up of senior officials from the two utilities and the Yukon government. Both groups meet regularly to ensure planning is done collaboratively and that programs are executed in a transparent and cooperative manner that avoids duplication.

Conservation Potential Review

Yukon Energy has been working to find out more about how people use electricity in the territory and where the greatest gains might be in terms of energy conservation and efficiencies. In 2011 we partnered with the Yukon Electrical Company Limited and the Yukon government's Department of Energy, Mines & Resources to collect this information.

We hired ICF Marbek to do a conservation potential review. Through its research, the company sought answers to the following questions:

- How do Yukoners currently use energy (i.e. what percentage of energy consumption goes towards heat, hot water, lighting, plug loads, etc.)?
- How much power would Yukon need in future years if there weren't any energy conservation/efficiency initiatives put in place?
- How much potential is there in Yukon for energy savings through conservation/efficiency initiatives?
- Where are the greatest gains to be made in terms of conservation of electricity?

The consultants gathered the information using customer billing data, stakeholder consultation and customer surveys. They processed all the collected data and returned to Yukon in November to share their initial findings. Through stakeholder "Achievable Potential" workshops they asked participants to talk about how much of the electricity savings identified in the draft report can realistically be achieved within Yukon's residential, commercial and renewable sectors.

Marbek used the feedback it received during these workshops to further refine its report. The final report is now available to the public.

One Change Community Tour

In the summer of 2011 Yukon Energy took our conservation message on the road. Together with Yukon Electrical Company Limited and the non-profit group One Change, we visited almost every community in the territory. We set up tents with interactive displays in highly visible areas, gave away energy efficient products, and talked to hundreds of Yukoners about what they think a territory-wide electricity conservation plan should look like. The input will assist us in our work to develop conservation programs for Yukon.

LED Streetlight Pilot Project

In 2011 we did research on Light Emitting Diode (LED) streetlights in Dawson City, with positive results. The research shows that the annual energy used by the traditional High Pressure Sodium streetlights is 416 kilowatt hours per light, compared with only 150 kilowatt hours per LED streetlight, a savings of 64 percent.

However LED technology is changing rapidly and we would like to test some options that weren't available to us when we started the pilot project. This year we will experiment with several different types of LED streetlights before deciding which types/brands will be the best for our Northern needs.

Alexco Mine Audit

In the summer of 2011 we partnered with Alexco Resource Corporation to do an audit of their mine site near Keno. We'll continue working with Alexco this year to implement some of the suggested energy saving measures. We will conduct similar initiatives with other Yukon mines and we will work with the City of Whitehorse to audit their facilities.

Internal Audit

Yukon Energy is also looking at our own operations as well with an eye to conserving energy. In 2011 we completed an audit of our Whitehorse and Dawson City office and plant buildings and we are prioritizing actions that will increase the efficiency of our facilities. Yukoners will be able to follow our progress on our website (www.yukonenergy.ca).

City of Whitehorse Audit

Yukon Energy has partnered with the City of Whitehorse to do an audit in 2012. This pilot includes a look at continuous improvement as part of the audit/planning cycles.

Fridge and Freezer Retirement Program

In 2011 Yukon Energy partnered with the Yukon government's Energy Solutions Centre to help members of the public replace their old refrigerators and freezers with new more energy-efficient models. The used appliances must be at least five years old and in working condition. Not only will Yukoners received $50 for each fridge or freezer they have replaced (up to two appliances) but the Energy Solutions Centre will remove the old model, take it to the landfill, and pay the landfill tipping fee. Yukon Energy will continue to support this program this year.

Online Energy Calculator

With assistance from Maritime Electric, we developed an online energy calculator in 2011. It allows Yukoners to determine how much electricity each of their household appliances and other electronic equipment requires to operate. The tool gives members of the public the ability to better manage their electricity usage and lower their power bills.

Tradeshows

In the spring of 2011, Yukon Energy ran a public awareness campaign that promoted the use of clotheslines. Employees set up a booth at an annual trade show in Whitehorse and gave away hundreds of packages of clothespins, along with several drying racks and clotheslines. We also provided tip sheets that included other energy saving information.

This year we will once again be set up at the Lion's Trade Show in Whitehorse with a very large Plinko game board. People will have a chance to play Plinko to win energy-savings products. We'll also have our Plinko board set up at Swan Haven on April 21 and 22 during Celebration of the Swans.

Dollars to Sense Workshops

Yukon Energy, working with Yukon Electrical Company Ltd., and Natural Resources Canada, hosted a series of energy management workshops in 2011 for Yukon businesses and First Nation and municipal governments. Sessions were offered both in the spring and fall. We will offer them again in future years if there is demand.

Energy Conservation Kids Ed-Venture Program

Yukon Energy and the Yukon Conservation Society partnered in 2011 to provide an afternoon of learning and fun for pre-schoolers, focused on energy conservation and electricity. The aim was to teach the children about using electricity safely and wisely. This was done through music and dance, storytelling, hands-on science and crafts. We plan to expand this program to other locations this summer.

Earth Hour

Yukon Energy worked with the Yukon Conservation Society and the Yukon government's Energy Solutions Centre both last year and this year to promote Earth Hour. It's an annual event that encourages people to reduce their energy consumption as much as possible for one hour, and think of ways that they could continue to conserve throughout the year. This year Yukoners reduced their energy consumption by about 1.1 megawatts. That's up from 2011, at which time Yukoners cut their consumption by 1 megawatt. In 2010 reduced their electricity usage during Earth Hour by .8 of a megawatt.

5.0 Conclusion

Yukon Energy is committed to working with Yukoners to develop a strong and effective energy conservation plan for the territory.

Over the last year the corporation and its partners have devoted a great deal of time and effort to building a framework for such a plan. However there is more work ahead, and your thoughts and suggestions are a crucial part of the planning process. Thank you for your time and support for a clean energy future.

Demand Side Management for the Yukon

- Initial stakeholder consultation (January 2011)
- Conservation Potential Review
- Program Design Development
- Market Characterization
- DSM Plan
- Implementation Plan
- Evaluation, Measurement and Verification Plan
- YUB Approval

Utilities DSM Process

- Total electricity consumption in 2010 - 312,000 MWh/yr
- By 2030 expected to rise to 515,000 MWh/yr, an increase of about 65%
- DSM measures could provide between 66,000 and 97,000 MWh/yr of savings by 2030

CPR Results

- The proposed programs focus on saving electricity
- The DSM Plan recognizes the importance of working with not for profits, community groups and government departments to deliver successful programs
- Jointly, the Utilities commit to an annual electricity conservation target of 8.5 GW/h of sustained savings by year five.

Scope

- The Utilities commit to work together to deliver the programs to all our customers
- Yukon Electrical will lead in the area of outreach and delivery of programs to customers
- Yukon Energy will provide technical expertise and lead in the overall accountability and reporting

Utilities Commitments

- Two scenarios – with and without government buildings
- The program portfolio projects 98.9 GW/h of measure-lifetime net savings.
- General Service programs including government buildings will generate 67% of the measure-lifetime net savings.
- Residential programs including government buildings will generate 33% of the measure-lifetime net savings

Savings Highlights

- Designing programs for the Yukon context
- Less than the Cost of Conserved Energy
- Passing the Cost Effectiveness Tests
- Identifying the program priority opportunities

Program Development

Test	Key Question Answered
Participant Cost Test	Will the participant benefit over the measure life?
Program Administrator Cost Test	How much will the DSM program administrator pay for savings?
Ratepayer Impact Measure	Will utility rates increase?
Total Resource Cost Test	Will the total costs of electricity in the utility service territory decrease?

Cost Effectiveness Tests

Residential Programs

- **LED Lighting & Automotive Heater Timer Rebates**
  - A flat rebate will be provided after the purchase of a lamp or fixture from a prescribed list of eligible products.
  - A flat rebate will be provided after the purchase of a block heater timer, car warmer and/or a battery blanket from an eligible product list.
  - 5 year total cost - $604,000 ($217,000 incentives)

- **Low-cost Energy Efficient Products**
  - The utilities will provide information to customers on certain low-cost items through retail outlets.
  - These include: low-flow showerheads, faucet aerators, DHW tank insulation, smart power bars, etc.
  - A limited number will be provided to customers free of charge and ask for feedback from those customers.
  - 5 year total cost - $1,033,000 ($192,000 incentives)

Residential Programs

Residential Programs

- **CCHP and GSHP Initiative**
  - A pilot program to test three-element hot water heaters, cold climate heat pumps and ground source heat pumps.
  - The technology will be subsidized, not provided free of charge and results will be provided.
  - This program will be available to new construction and retrofit homes
  - 5 year total cost - $209,000 ($65,000 incentives)

- **Public Engagement, Education and Communication**
  - Information will be provided to customers through the following channels:
    - Engagement with the retail sector
    - Point of purchase displays and brochures
    - Partnerships with non-profit and community agencies
    - Outreach and participation in community events
    - Identification of electricity efficiency partners
    - Efficiency workshops
    - Direct engagement with contractors
    - Advertisement
    - Website
  - 5 year total cost - $657,000

Residential Programs

- **Lighting Redesign and Equipment Incentive**
  - An incentive will be paid to have building lighting systems redesigned.
  - The custom incentive includes a base incentive for equipment and installation using a dollar per kilowatt hour annual savings rate.
  - An additional incentive is provided for choosing LED products
  - 5 year total cost - $1,487,000 ($1,062,000 incentive)

General Service Programs

- **High Efficiency Refrigeration Incentive**
  - An incentive will be paid to have refrigeration systems retrofitted.
  - This will be a custom incentive using a per kilowatt hour rate for each kilowatt hour saved.
  - Extensive refrigeration-specific technical assistance will be provided to assist in identifying the opportunities
  - This program is aimed at hockey, curling rinks and grocery stores.
  - 5 year total cost - $553,000 ($263,000)

General Service Programs

- **ENERGY STAR Computer Incentives**
  - An incentive will be paid to Yukon-based companies or organizations that purchase computer equipment that meets ENERGY STAR requirements.
  - The incentive will be a fixed amount per piece of equipment.
  - 5 year total cost - $284,000 ($98,000)

General Service Programs

- **New Construction Incentive**
  - An incentive will be paid for high performance new buildings.
  - The program will have two paths: a prescriptive path for small buildings and a custom path for large buildings.
  - The prescriptive incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard
  - The custom incentive will be determined using a dollar per kilowatt-hour of annual savings
  - 5 year total cost - $208,000 ($115,000 incentive)

General Service Programs

- **Engagement, Training and Communication**

  - Information will be provided to customers through the following channels:
    - Direct Engagement with building actors (electrical distributors, lighting designers, electrical contractors, etc)
    - Hands-on, in-person courses for local building actors
    - Project-specific lighting design or advanced HVAC design technical support
    - Trade events and gathering local building owners/managers and building actors
    - Support for building owners/managers to do asset management planning, optimizing decisions about implementation and procurement, tendering of project design service, etc.
  - 5 year total cost - $1,199,000

General Service Programs

- Public face of the Utilities for delivery of the programs
- To provide a one stop brand for customers to search, talk to and engage with
- Lessens Yukon Energy/Yukon Electrical confusion.

inCharge Brand

Costs

	Annual Cost	Annual Savings
Year 1	$824,000	240 MWh
Year 2	$1,240,000	1487 MWh
Year 3	$1,393,000	4318 MWh
Year 4	$1,266,000	6451 MWh
Year 5	$1,480,000	9250 MWh
Total	$6,203,000	

These costs are split 50/50 between Yukon Energy and Yukon Electrical

- Mechanism to report, evaluate and verify savings realized versus forecast savings
- Verify performance of programs and provide recommendation for improvements
- Provide a framework of accountability
- Completed by a certified third-party evaluator

Evaluation, Measurement & Verification (E,M & V)

- CPR, DSM Plan and supporting documents submitted as part of Yukon Electrical GRA
- Deliver Implementation Plan and EM&V Plan to the YUB - July 2013
- GRA decision expected by first quarter 2014

Next Steps

Yukon Energy Corporation and

The Yukon Electrical Company Limited

Demand Side Management Plan

January 13, 2011 Focus Group Session

Synthesis Report

Prepared by Paul Kishchuk, MA
Vector Research

February 28, 2011

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Introduction

The Yukon Energy Corporation and The Yukon Electrical Company Limited were directed by the Yukon Utilities Board in 2009 to jointly develop a Demand Side Management (DSM) Plan. Development of the DSM Plan is to involve intervenors, communities and stakeholders. The completed DSM Plan will be reviewed by the Yukon Utilities Board.

Both the Yukon Energy Corporation and The Yukon Electrical Company Limited also recognize that electricity use in Yukon is increasing each year. By influencing consumer behavior through the delivery of incentives/disincentives for using electricity at certain times or for certain purposes it is hoped that that need for electricity from new generation sources can be reduced and/or delayed.

The DSM Plan will also be developed within the context of the Yukon Government's *Energy Strategy for Yukon* which calls for the development of a demand management program. The Yukon Energy Corporation and The Yukon Electrical Company Limited are working with the Yukon government to ensure consistency with current DSM initiatives.

On January 13, 2011 the Yukon Energy Corporation and The Yukon Electrical Company Limited initiated public participation in the development of the DSM Plan by hosting a focus group session with an invited group of participants. A total of 15 participants, representing a broad selection of stakeholder and community agencies, attended the January 13 session. The individual participants and the organizations they represented are listed below in alphabetical order:

Shane Andre – YG Energy Solutions Centre
Shannon Clohosey – City of Whitehorse
Marianne Gregoire – YG Highways & Public Works
Lawrence Ignace – Indian and Northern Affairs Canada (Yukon Region)
Rick Karp – Whitehorse Chamber of Commerce
Juergen Korn – YG Yukon Housing Corporation
Laurie MacFeeters – Yukon Anti-poverty Coalition
John Maissan – Leading Edge Projects Inc.
Anne Middler – Yukon Conservation Society
Steve Mooney – Yukon Cold Climate Innovation Centre
Manon Moreau – YG Energy Mines and Resources (Energy Strategy)
John Pattimore – Association of Yukon Communities
Roger Rondeau – Utilities Consumer Group
Mike Wark – Yukon Chamber of Mines
Rebecca World – YG Climate Change Secretariat

A representative from both the Yukon Energy Corporation and The Yukon Electrical Company Limited were also present at the session to assist with technical questions:

Hector Campbell – Yukon Energy
Christopher Cullingham – The Yukon Electrical Company Limited

The facilitators for the focus group session were:

Paul Kishchuk – Vector Research
John Streicker – Professional Engineer

Notes were taken at the focus group session by Ramona Toth.

As the focus group session was the launch for public participation in the development of the DSM Plan, Mssrs. David Morrison and Dwight Redden made brief opening comments on the context for the DSM work being undertaken by both utilities before taking their leave from the session. David Morrison is the President and CEO for Yukon Energy Corporation and Dwight Redden is the General Manager for The Yukon Electrical Company Limited.

The stated purposes of the half-day session were to:

1) identify key demand side management issues from the perspective of the agencies and organization represented at the session; and,
2) seek direction on how to best involve agencies and organizations present at the session in the development of a demand side management program.

The focus group session commenced at 9:05 a.m. and wrapped up at 12:00 noon.

The focus group session was carried out in accordance with the Chatham House Rule. Participants were advised that they could, subsequent to the session, talk about what they had heard and learned at the session but that they were not at liberty to do so in a way that would reveal the identity of an individual or organization. In fulfillment of the Chatham House Rule commitment made at the focus group session, no statements, remarks or suggestions are attributed to specific individuals or organizations in this report.

As the responses to each of the questions outlined below are presented in no particular order, no meaning should be attached to the order in which a response appears within a list.

Why is your organization interested in energy issues?

- Because we are working to implement government policies (Energy Strategy, Climate Change Strategy) or programs (homeowners, energy efficiency programs, infrastructure, Cold Climate Innovation);
- We represent businesses and industry who as large electrical energy consumers are correspondingly exposed to cost increases;
- We represent people and organizations concerned about CO_2 emissions, environmental impacts, energy efficiency (conservation), electric bill costs, energy security; and,
- We represent people and organizations hoping to educate and create a culture of electrical energy conservation among people and within organizations.

What are some examples of Demand Side Management programs and initiatives?

- The encouragement of a "conservation culture" where behaviors are shifted and knowledge encouraged so that people are aware of their individual consumption impacts;
- Programs delivered by B.C. Hydro for low income individuals/renters;
- Consumer awareness tools such as pie charts for electricity rates at certain times of the day;
- Education about how to conserve electricity so that everyone can make changes;
- Energy conservation or efficiency programs via the customer base such as energy rebates, load shifting or adding loads;
- Good "real time" information (e.g., graphs, billboards, turning off streetlights) to make it easier for people to visualize and comprehend limits and know when to shift loads;
- Hot water tank timers and low flow showerheads;
- Targeted education and implementation of programs for low income people and renters (could include modifications to rate structure) since there is no point in delivering programs to people who cannot take advantage of them;
- Transparent information for consumers so they can understand how the different rates, riders, rebates and taxes all fit together;
- DSM incentives for renters whose electrical bills are paid by their landlords;
- Energy efficient building design since good design is more economical than retrofitting;
- Electricity rate structures that discourage electricity consumption at times of hydro-electric under-supply and encourage electrical energy use at times of hydro-electric over-supply;

- Standards/regulations for all new buildings through revisions to building codes that incorporate energy efficiency;
- Strategic use of energy;
- Supply side management of electricity by the utilities (e.g., during peak morning an evening periods);
- Load shifting by mines so that consumption is reduced during times of peak consumption on the grid, perhaps through monetary disincentives tied to whether or not diesel-generated electricity could be avoided through reduced electricity consumption by industrial customers (it was pointed out that coordination of demand responses with large-scale customers is typically already being done by electricity suppliers);
- Better bill information so that consumers know when they've jumped to a higher rate block, similar to a telephone bill that shows the difference in cost if you made a call during a peak period versus a discount period versus a "deep" discount period, perhaps there could be an addendum to the bill explaining the details of how the bill was calculated;
- Consumer education (including units of measure and other basic electricity concepts) so that when consumers are reviewing their bills they understand how the bills were calculated;
- An understanding of the audience and client base needs to be developed to be able to properly target DSM information to different consumers;
- We should consider all potential DSM opportunities rather that focusing on savings in just one area of electricity consumption;
- Perhaps larger-scale consumers could sign some sort of risk/confidentiality waiver and work directly with the Energy Solutions Centre through the sharing of bill information; and,
- Government to government transfers could be tied to implementation of energy efficiency and conservation measures (parallel idea to sustainability plans and gas tax funding).

Are there any specific DSM initiatives not well suited to the Yukon?

- Adoption of time-of-use rates in the Yukon needs to be further explored including comparisons with other measures such as load shifting from day to night;
- If new supply cannot be avoided, it was pointed out that some other jurisdictions are reconsidering nuclear options, something which may not be acceptable to Yukoners;
- DSM initiatives that create consumption disincentives for mine operators need to recognize that electricity is an integral input to mining processes, mines exist to make money and reducing production reduces income. Unexpected shutdowns can affect workers pay. This is not to say that the mines and mine workers disagree with DSM, just needs to be done in a feasible way;
- The obligation to serve provision of the *Public Utilities Act* (i.e., if a mine builds a power line to the grid the utility must build capacity and supply electricity), which can adversely affect existing customers on the grid, should perhaps be revisited;
- If supply is to be scaled back at times of peak consumption, there needs to be a public discussion about how to choose who gets power first (i.e., whose electricity supply is reduced);
- DSM initiatives should be avoided that increase the use of diesel generation in or near communities where noise and air pollution are issues. Diesel generation may best be located next to the industrial users, like mining operations, where waste heat from the generators could economically be used to heat buildings;
- We should look at the larger consumption issue and not just savings in one area; and,
- DSM initiatives that result in less electric heating being available to residential customers and indirectly contribute to increased use of heating methods which diminish air quality (such as the burning of wood or oil to produce heat), should be discouraged.

If you could have your pick, which DSM program or initiative would be the first choice for your organization?

- A public education campaign to promote awareness of how to reduce electricity consumption [suggested by five participants];
- All new building construction built and maintained to be as energy efficient as possible.
- An on-going marketing campaign about electrical energy as no one understands it and doesn't worry about it until it's gone;
- Continued evolution of our electrical bills (monthly usage chart on current version of electrical bill is useful), however information needs to be at grade 7 level to ensure greatest number of consumers benefit from information availability;

- Design and implement tools/information for employees of large organizations (who now feel powerless to conserve energy in the workplace) to allow them to demonstrably conserve energy in the workplace;
- Design and implementation of an electricity rate structure that encourages DSM-like behaviors;
- DSM measures that have some sort of "price shock" aspect (e.g., like over-threshold internet access charges), can be effective as people will learn from it;
- Electrical energy guidelines, regulations and accessible information needs to be specific to each Yukon community as each community is different;
- Employees of large organizations are also electricity users at home so education efforts in the workplace can have indirect benefits in the residential sector;
- Energy audits in small communities to establish baselines for electricity conservation initiatives;
- It needs to be remembered that it is difficult to ask industrial users such as mines to shut down or scale down on short notice as it is akin to asking mine workers to give up their pay cheques, such shut/scale downs need to be properly planned out to minimize effects on mine operations (and it was noted that this type of planning is already done);
- Loan programs for upgrades whereby the savings are used to pay off the loan;
- Money is required for all DSM programs, since implementing DSM programs can be far cheaper than building new infrastructure or waiting for existing infrastructure to wear out;
- Programs that result in implementation of DSM programs are required;
- Regulations to encourage energy conservation (such as improved building codes), while likely the most tricky to implement, will be the most valuable/effective;
- Smart metering for households (including smart hot water heaters);
- The electrical utilities should network with consumers and businesses to transfer information about the benefits of electrical energy conservation, people need to be able to see the "light at the end of the tunnel" if they are to adopt new consumption habits that will stay with them;
- The greatest conservation successes will come from more energy efficient building design and construction rather than from retrofitting existing buildings;
- Thorough follow-up and assistance with DSM initiatives and programs to ensure effective implementation and actual savings – for example, it's not good enough to hand out low-flow showerheads if people don't know how to install them and they end up sitting on a shelf;
- Transparent linkages between electricity-conserving behaviour and cost savings; and,
- Whatever programs are chosen to implement, the potential for savings exist right know, let's get them implemented ASAP!

What are the perceived barriers to the uptake of DSM programs that come to mind?

- Conservation is a lifestyle change that people need to make and if people are to change they must perceive that it is somehow "worth it";
- Finding funding for DSM programs will be a barrier, the funding has to come from either electricity rates or taxes;
- Good program design requires the collection of accurate statistics on the number of people on electric heat as well as the number of people living in houses that that need retrofitting;
- If minimum specifications are regulated (i.e., building codes) retrofitting will become even more costly in the future; we already have an affordable housing problem so if building codes are changed to increase minimum standards, housing will become even less affordable, this also needs to be addressed; it was pointed out that the payback on more efficient building construction is immediate, a person will pay less in energy costs than they will in the incremental increase in mortgage costs (in other words the savings in operational costs more than offset the increase in capital costs);
- Incentive-type programs/initiatives are not always worth it in terms of conservation results;
- People are generally willing to pay more for something that brings convenience, problem with electricity is that it costs the same whether used for a basic need (e.g., hot water) or a convenience (e.g., hair drier);
- Reductions in consumption will reduce revenues for the utilities so in times of surplus electrical energy the utilities will be less vigilant about conservation, as a result need to think about how to ensure energy conservation is "always in fashion" for the utilities and consumers alike;
- Retrofitting is expensive and may not be feasible for everyone;
- Strong leadership from YEC and YECL and YG is required. "If you build it, hopefully people will follow";
- The capacity of people to adopt changes needs to be considered in the design of DSM programs. For example, someone working 3 jobs will not likely have the energy/time to make good conservation choices;
- The greatest challenge is getting buy in from the public to conserve energy;
- There are currently no incentives for renters to conserve electricity; and,
- There is always a fear of change and that people may feel that they don't need education so there could be public resistance if there is not proper information.

Who should pay for the design and implementation of DSM programs and initiatives?

- Both ratepayers and taxpayers have a duty to pay (and likely both will pay);
- DSM initiatives likely cannot offset all the need for new generation, rates will go up as new generation is built, public may perceive that DSM is wasted effort since rates are going up anyways, how to convince people that rates will go up less if they conserve electrical energy?;
- Educating taxpayers is the same thing as getting government to pay;
- Government is already contributing because of the cross subsidy from government to residential customers;
- Remember that conservation programs aren't all about costs since reducing consumption results in saving for consumers; and,
- The bill subsidies now in place should continue to be in place until DSM programs/initiatives are implemented and education activities are in progress.

How should it be decided which agency or organization will be the lead on a particular program or initiative?

- Both utilities (YEC & YECL) should make the case for DSM to the public and then agencies and organizations should make contributions as appropriate;
- Collaboration is important but one entity needs to "take the reins" and lead and also facilitate partnerships;
- Let's get going on a Public Awareness Campaign!;
- Partnerships are key;
- Terms of Reference to the Yukon Utilities Board could be a starting point;
- The Department of Education should be involved so that young people can be involved and perhaps will come home and help educate parents;
- The Yukon Government and the electrical utilities have concurrent responsibility for DSM; and,
- Ultimately it will be the government's lead, as they will direct the utilities that they implement DSM programming (it was pointed out that utilities are already on board);

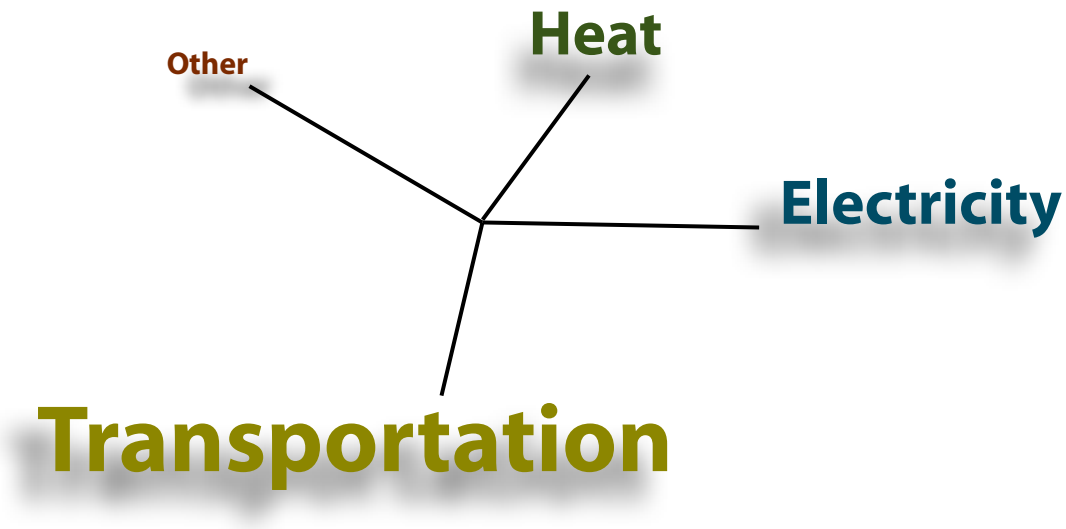
Going forward, what form of engagement would you like to see? Should other business/organizations be involved?

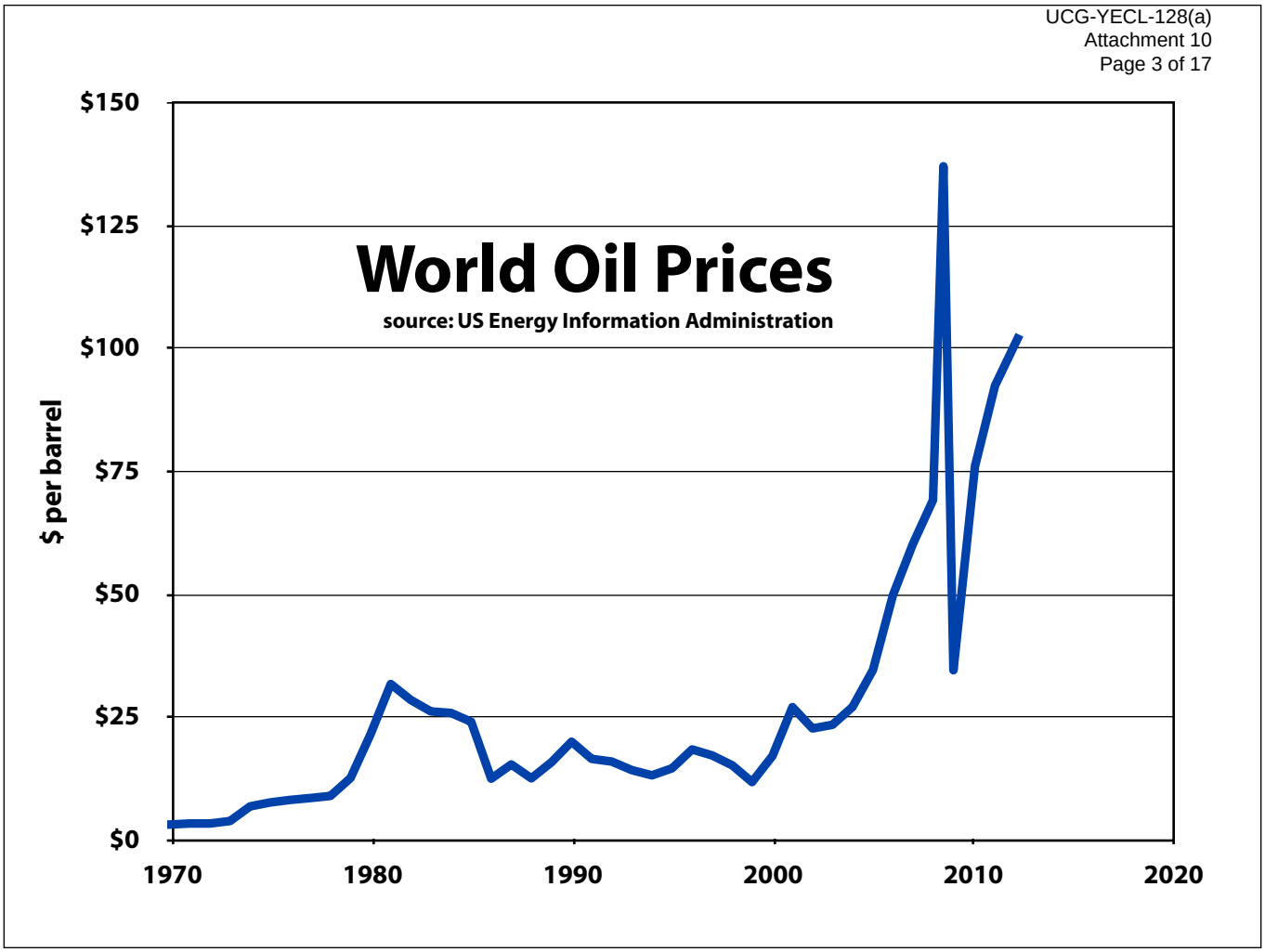
- Among participants there was general agreement that the focus group session was a good start and that the organizations they represent would be glad to continue to participate and help in any way they can, including communicating with the members of their organizations;
- An organization represented at the focus group noted they have networking as part of their mandate and would be happy to facilitate further discussion on the topic of DSM;
- Continued facilitated discussions like this one, having a variety of stakeholders to work with is essential;
- Consumers should be encouraged to contribute ideas and engage and participate in DSM planning;
- Continuing to work in a forum similar to today's focus group would be beneficial;
- Create a "DSM website" hosted by the utilities that can be a repository for DSM information for this working group as we move forward;
- Create an email list for the focus group participants as a way of staying in communication;
- Develop strategies to get input from the public;
- Empower grassroots individuals and organizations sooner rather than later and keep them informed;
- Partnerships between the utilities and other agencies and organizations;
- Real timelines need to be set and communicated, organizations need to be kept informed;
- The utilities need to have direct contact with the business community to discuss DSM initiatives;
- The utilities should take ownership of the issue at the start and then utilize other groups to move forward;
- There should be direct discussions between the utilities and industrial consumers (i.e., mines); and,
- Utility-led group discussions on DSM within organizations represented at the focus group.

Why DSM?

Sustainability for the Yukon

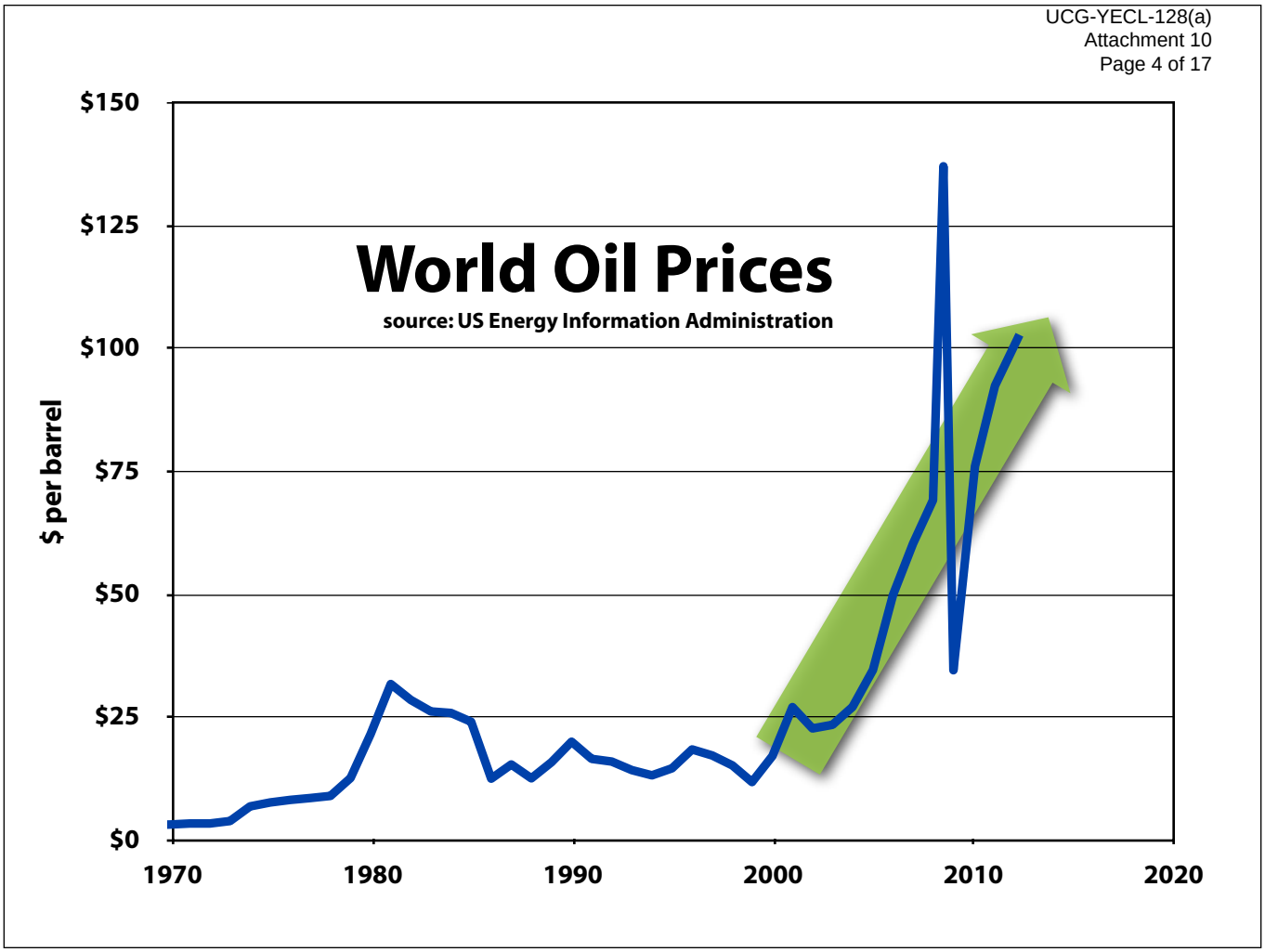
Yukon Energy





Data Source: US Energy Information Administration

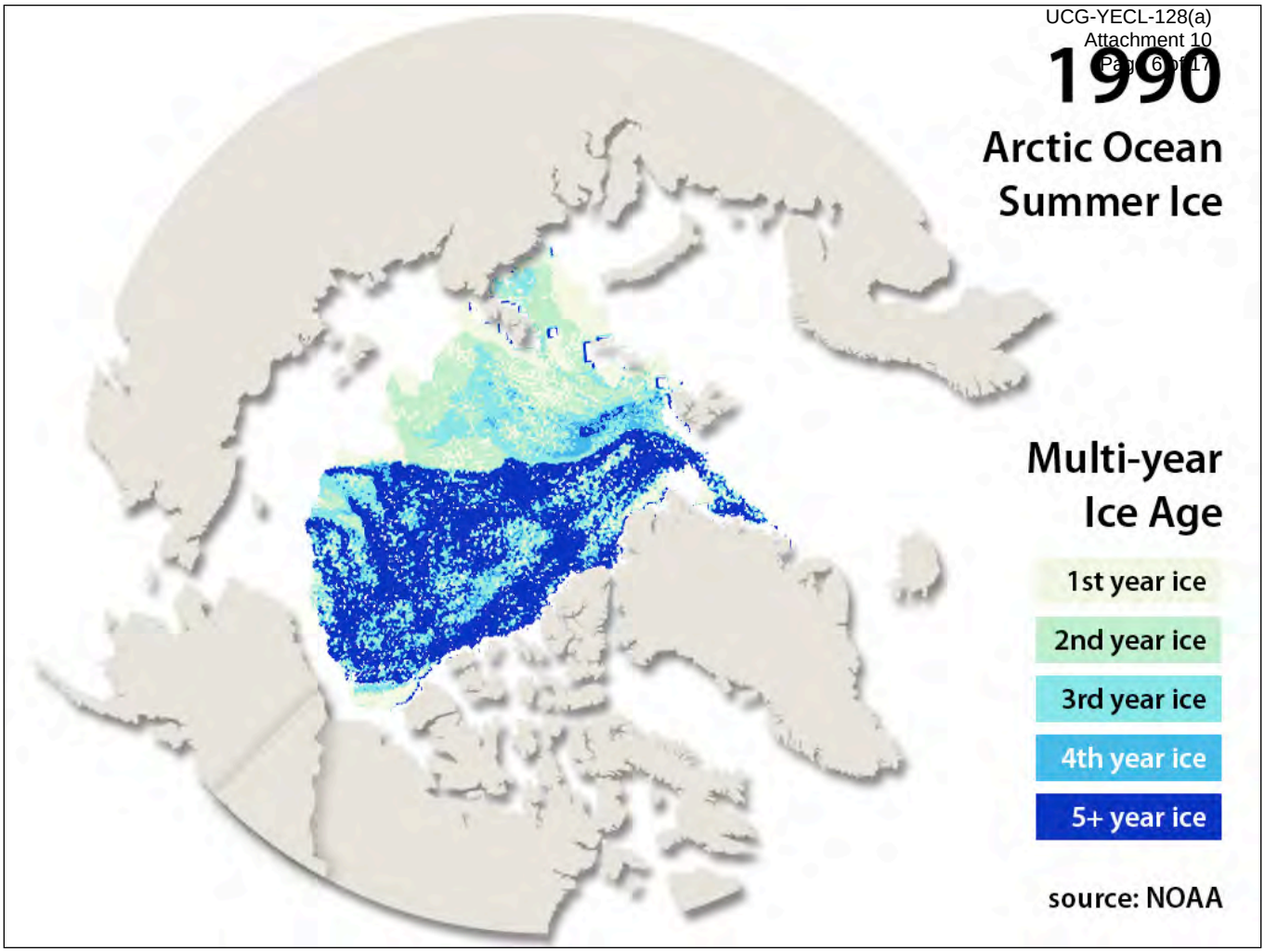
Graph Source: John Streicker



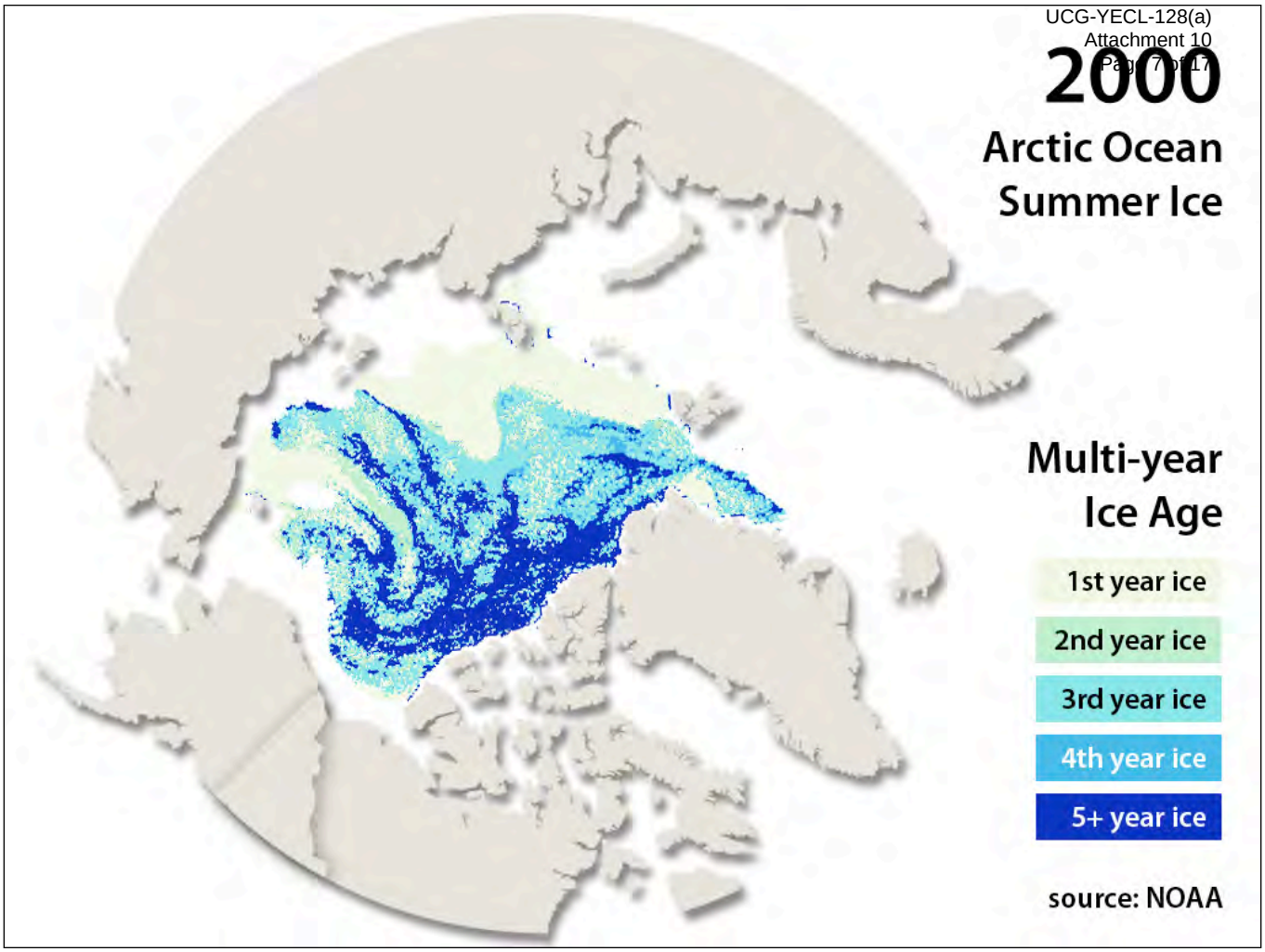
Data Source: US Energy Information Administration

Graph Source: John Streicker

Consumption



Data Source: National Oceanic and Atmospheric Administration (NOAA) with data from James Maslanik, University of Colorado
Image Source: John Streicker



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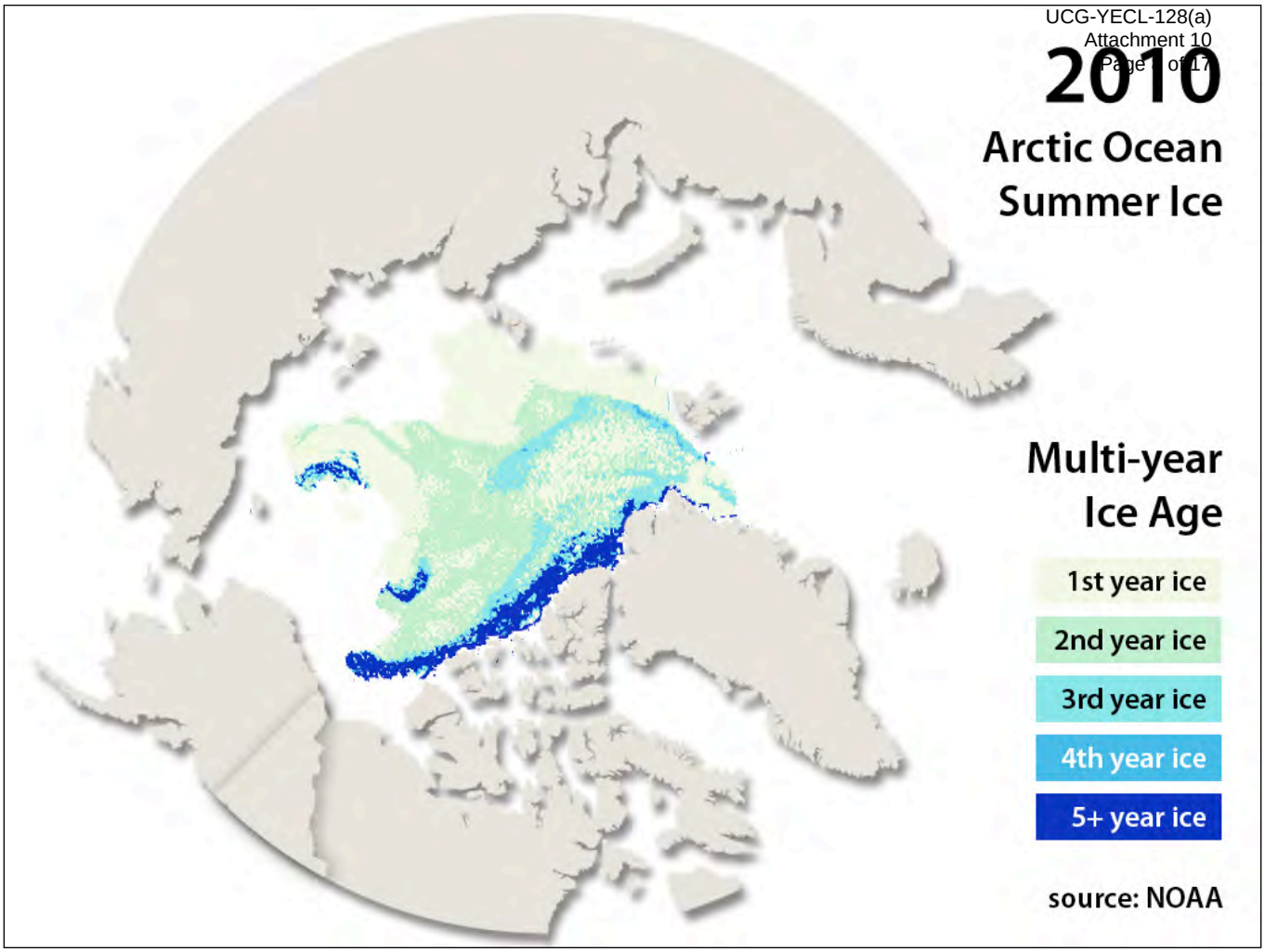

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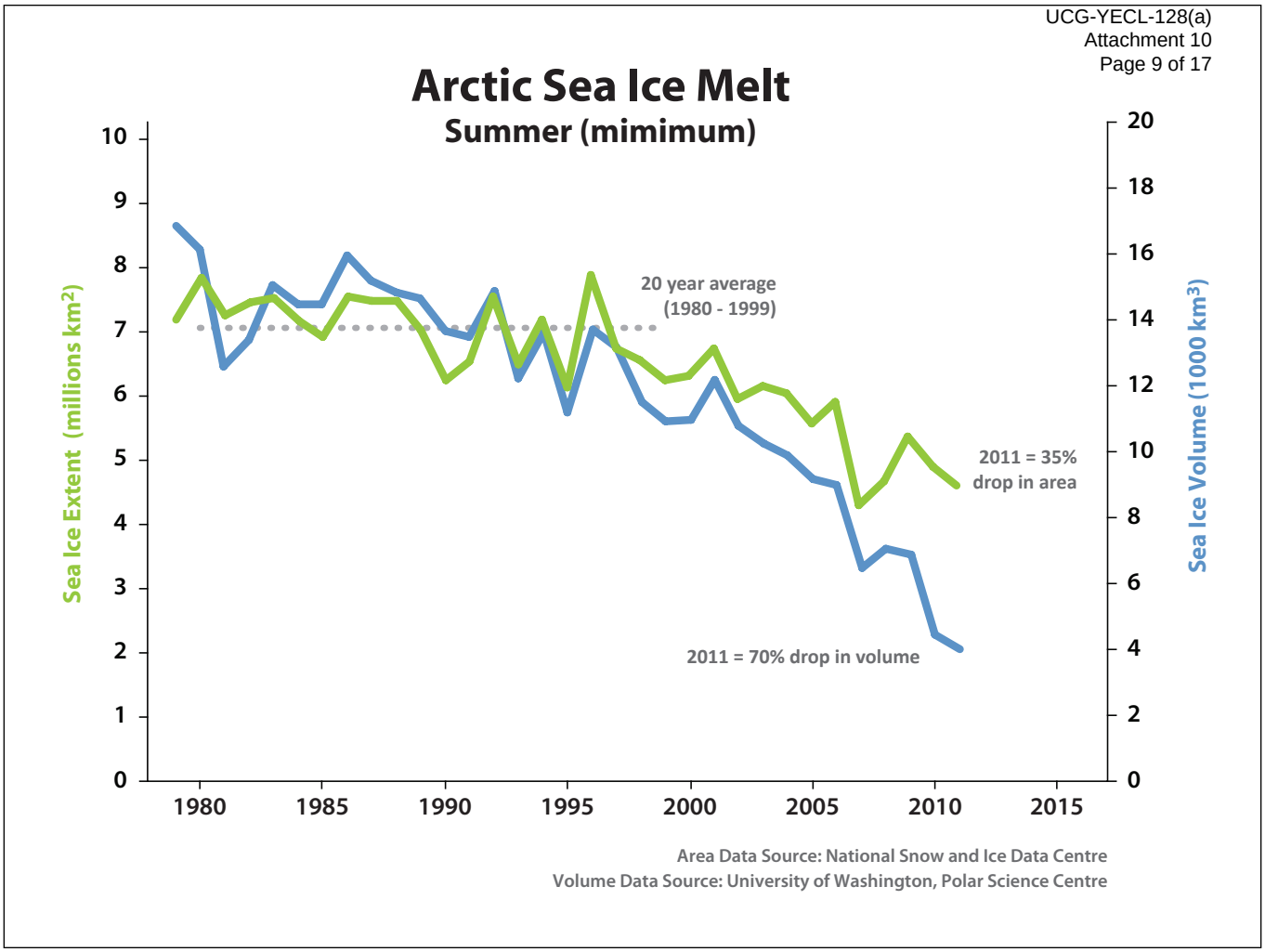
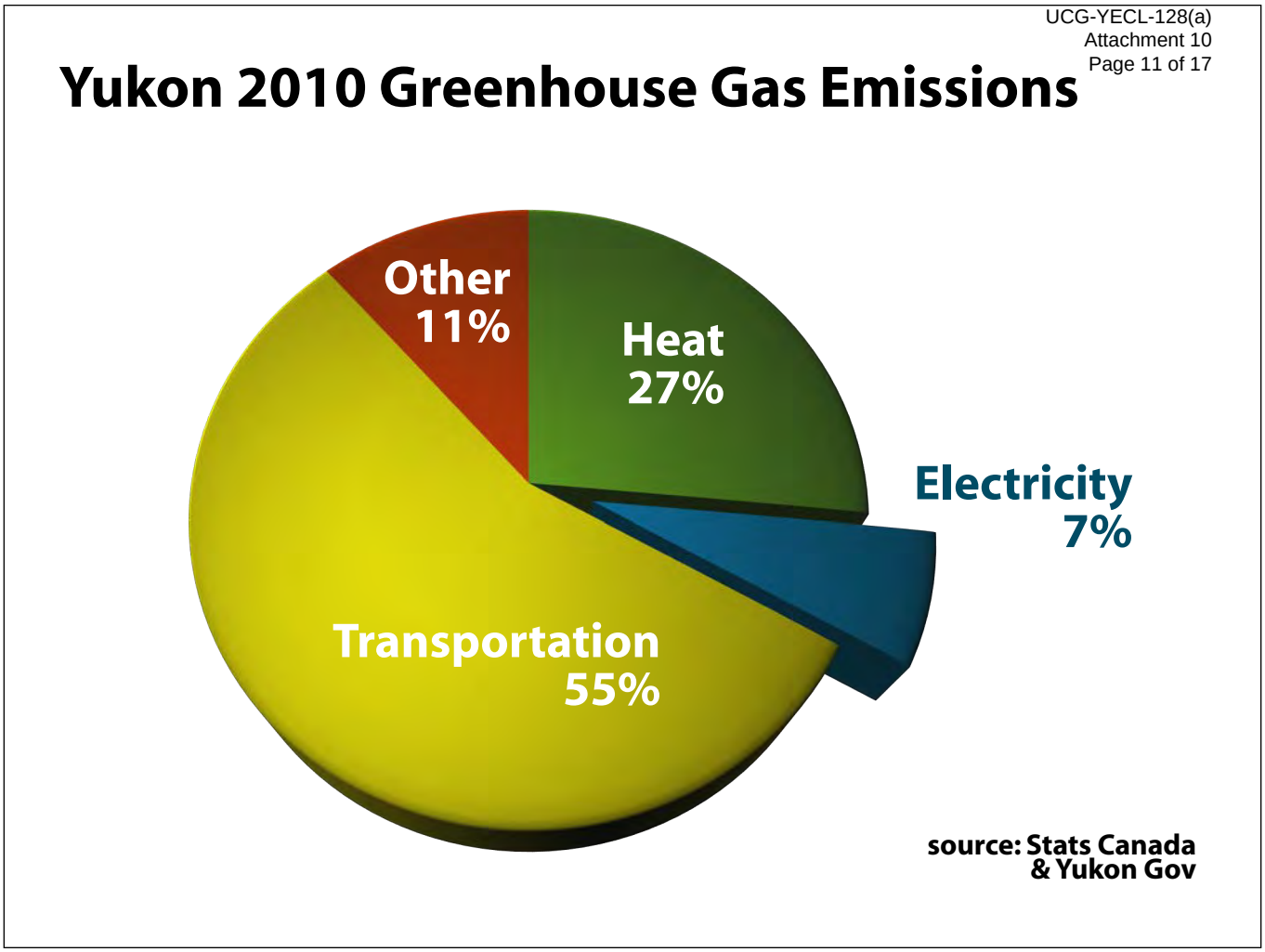


Data Source: National Snow and Ice Data Centre (NSIDC) and Polar Science Centre at University of Washington
Graph Source: John Streicker

“If we don’t change our energy system in a radical way in the next ten years, the wheels will come off.”

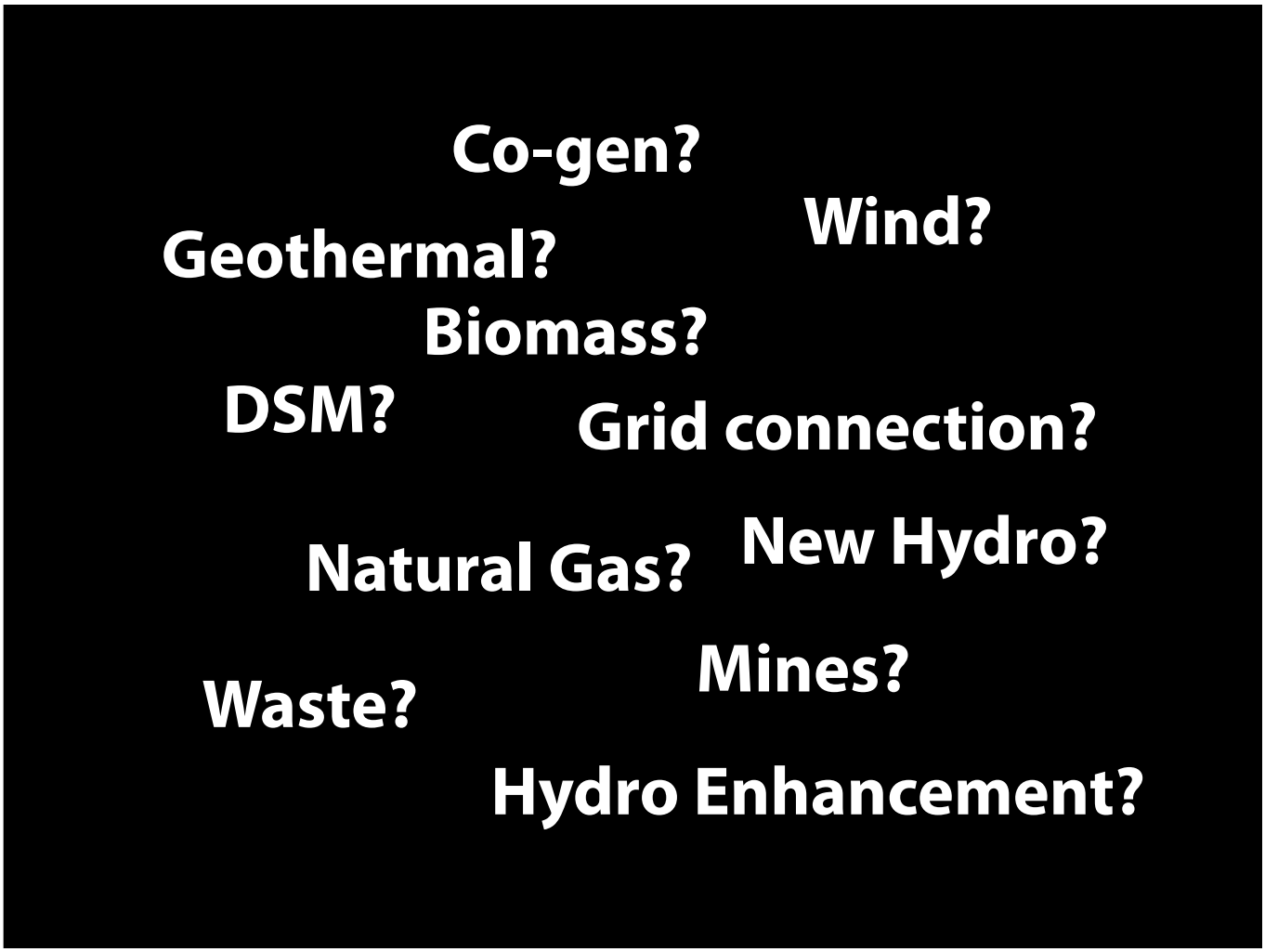
- Fatih Birol, Chief Economist, IEA, 2007

Notes:Quote is from press release around the International Energy Agency’s World Energy Outlook, 2007



Data Source: Statistics Canada and Yukon Government Climate Change Secretariat

Graph Source: John Streicker


Co-gen?
Wind?
Geothermal?
Biomass?
DSM?
Grid connection?
New Hydro?
Natural Gas?
Mines?
Waste?
Hydro Enhancement?

1. reliability
2. affordability
3. flexibility
4. environmental responsibility

#1 - conservation

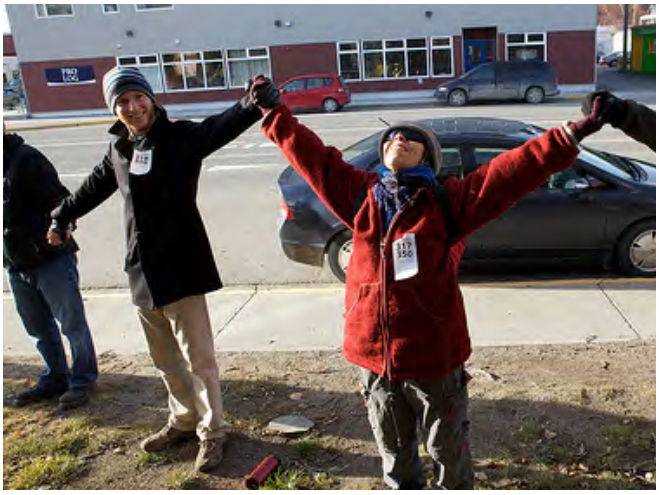
#2 - efficiency

at the consumer level

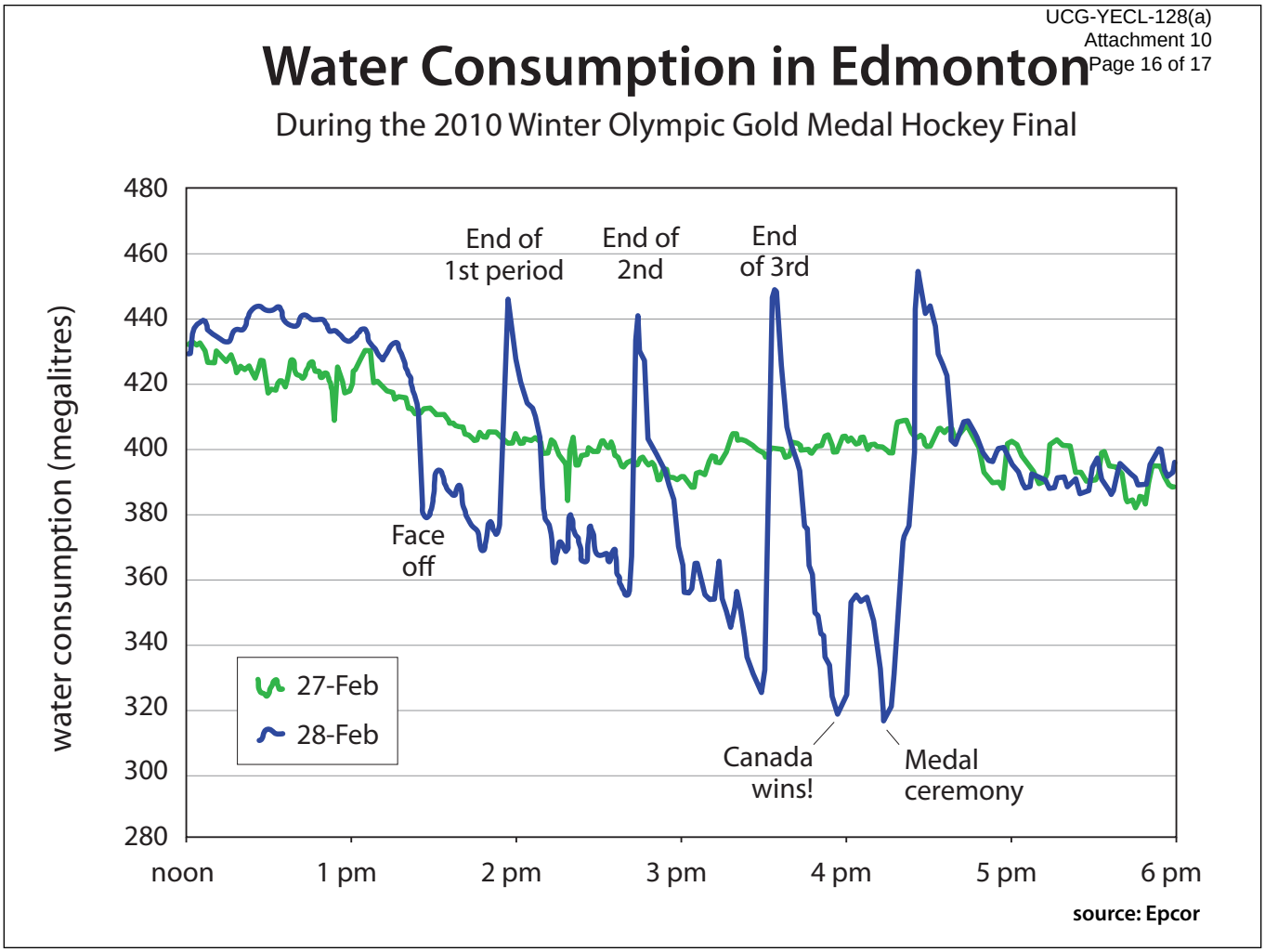
conservation

+ efficiency

= DSM



Behaviour



Notes:

1. The 2010 Olympic Men's Hockey gold medal final match on Sunday 28-Feb was a great example where a behavioural change could happen
2. Edmonton monitors its water usage at all times
3. Someone noticed that the water usage on 28-Feb was very different from the day before, Saturday 27-Feb
4. It is very easy to see the signature of the hockey game on the water usage chart, including the three periods, the overtime and even the medal ceremony
5. During the game, water consumption dropped by 5%
6. All it took was people flushing between periods

Data Source: EPCOR

Graph Source: John Streicker

Big Picture

Photo Source: John Streicker

Yukon Electrical – One Change – YEC Tour

Summary

Yukon Electrical and Yukon Energy have engaged the One Change Foundation to conduct a tour across the Yukon to stimulate conversations among community leaders and the general population that will assist in guiding the utilities towards a territory-wide energy conservation policy.

Staff Assignments

Team #1	Team #2
Deb Gleason-One Change	Stuart Hickox (plus 1)-One Change
Allison Fitzgerald -One Change	Christine (plus 1)-One Change

Event Dates

Old Crow	June 23	Team #2 – Dwight, Wendy & Jay
Faro	June 24	Team #1 – Laura
Dawson City	June 25	Team #2 – Wendy
Ross River	June 25	Team #1 - Laura
Pelly Crossing	June 26	Team #1 – Laura
Carmacks	June 27	Team #1 – Laura & Wayne
Teslin	June 27	Team #2 – Wendy & Jay
Whitehorse	June 28	Team #1 – Wayne & Laura (Laura at public meeting)
Watson Lake	June 28/29	Team #2 - Wendy & Jay
Burwash Landing	June 29	Team #1 – Laura & Wayne
Haines Junction	June 29/30	Team #1 – Laura & Wayne
Whitehorse	July 1	Team #1 & #2 – Laura & Wendy

Pre-tour Timeline

Wednesday, June 15			
	Klondike Sun Ad		¼ page ad to run
	Yukon News Ad		¼ page ad to run
	Confirm arrangements for Birthday Cake, food and beverages		Wendy
	Tents arrive Whitehorse		YECL Office
Friday,			

June 17			
	Yukon News Ad		¼ page ad to run
Monday, June 20			
	Prep YECL packages		Laura & Wendy
	One Change materials arrive • 2 tables • Mascot • 2 tents • 300 medium boxes • 2 large boxes Game wheel		Delivery to be arranged by One Change Arrived June 17
Tuesday, June 21			
	One Change (Deb & Allison arrive in Whitehorse)	1:39 pm	Laura to pick up at airport Flight AC 8443
	One Change bag prep day		YECL basement
Wednesday, June 22	•		
	One Change (Stuart and son) arrive in Whitehorse	1:39 pm	Laura to pick up at airport Flight AC 8443
	One Change bag prep day		YECL basement
	Yukon News Ad		¼ page ad to run
Friday, June 24	Christine arrive at airport	1:39 pm	Flight AC 8443

Tour Timelines

Thursday, June 23	
Team 1	
	YECL Offices for continued set-up
Friday, June 24	
Team 1	
11 am	Depart Whitehorse Faro
3 pm	Arrive Faro
6:30 – 8 pm	Faro Public Event Tina Freake, Recreation Manager 867-994-2375
9 pm	Faro Accommodations Valley B&B
Saturday, June 25	
Team 1	
10: 30 am	Depart Faro for Ross River
11:30 am	Arrive Ross River
1 – 3 pm	Ross River Public Event between the band office and the store Sharon - 969-2277
4 pm	Depart Ross River for Carmacks
8 pm	Arrive Carmacks – Mukluk B&B
Sunday, June 26	
Team 1	
10:30 am	Depart Carmacks for Pelly Crossing
11:30 am	Arrive Pelly Crossing
1 – 3 pm	Pelly Crossing Public Event at Link Building Candace 537-3331
4 pm	Depart Pelly Crossing

Thursday, June 23	
Team 2	
8:30 am	Arrive at Airport - Alcan
9:30 am	Depart Whitehorse for Old Crow (Alcan Air)
11:30 am	Arrive Old Crow – pick up by
1:00-2:00 pm	Old Crow First Nations Meeting (Vuntut Gwitchin First Nation) Community Center
6:30-8:30 pm	Old Crow Community Event Community Center
9:00 pm	Depart Old Crow for Dawson City (Alcan Air)
9:30 pm	Arrive Dawson City Wendy and Dwight to deplane
9:30 pm	Pick up at airport by Yukon Hotel – Wendy and Dwight
10:00 pm	Depart Dawson City for Whitehorse (Alcan Air)
11:30 pm	Arrive Whitehorse
Friday, June 24	
Team 2	
1 – 2 pm	Dawson City Council Meeting at
Saturday, June 25	
Team 2	
1-3 pm	Dawson City, Public Event At the shelter at the weir.
Sunday, June 26	
Team 2	
	Return to Whitehorse

5 pm	Arrive Carmacks – Mukluk B & B
Monday, June 27	
Team 1	
	First Nations Meeting
1 – 2 pm	Village of Carmacks Meeting Council Chambers
6 – 7:30 pm	Carmacks Public Event
8:00 pm	Depart for Whitehorse
10:00 pm	Arrive Whitehorse
Tuesday, June 28	
Team 1	
11 am – 1 pm	Whitehorse Public Event
3 – 5 pm	Whitehorse city council meeting at Heritage room at City Hall.
Wednesday, June 29	
Team 1	
9:00 am	Depart Whitehorse for Burwash Landing
	Arrive Haines Junction
2 pm tentative	Burwash Landing First Nation meeting (Kluane First Nation)
4:30 – 6:30 pm	Burwash Landing Public Event Grace Southwick 334-3635 cell
7:30 pm	Depart Burwash Landing for Haines Junction
9:00 pm	Arrive Haines Junction – Alcan Motor Inn
Thursday, June 30	
Team 1	
1 – 2 pm	Haines Junction First Nation meeting (Champagne-Aishihik First Nation)
4:30 – 6:30 pm	Haines Junction Public Event
7:30 pm	Depart Haines Junction for Whitehorse
9:00 pm	Arrive Whitehorse
Friday, July 1	
	Teams meet at YECL offices to load vehicles
	Arrive at Shipyards Park for set-up

Monday, June 27	
10:30 am	Depart Whitehorse
12:30 pm	Arrive Teslin
1:30 – 2:30 pm	Teslin First Nation meeting (Teslin Tlingit Council)
4 – 6 pm	Public Event
7-7:30 pm	Village of Teslin council meeting at town office
7:45 pm	Arrive at Yukon Motel for overnight accommodations
Tuesday, June 28	
Team 2	
	Depart Teslin for Watson Lake
	Arrive Watson Lake
12-1 pm	Town of Watson Lake meeting
1:30 – 2:30 pm	Watson Lake First Nation meeting (Liard First Nation)
	Watson Lake Public Event
Wednesday, June 29	
Team 2	
	Depart Watson Lake for Whitehorse
	Arrive Whitehorse
Thursday, June 30	
Team 2	
	Prepare for July 1st event
Friday, July 1	
	Teams meet at YECL offices to load vehicles
	Arrive at Shipyards Park for set-up

10:00 am	Public Event start
	Public Event end
	Return to YECL Offices to unload
Saturday, July 2	
	Breakdown materials and sort

10:00 am	Public Event start
	Public Event end
	Return to YECL Offices to unload
Saturday, July 2	

Accommodations

Team 1
Laura Carlson & Wayne Tonsi (Burwash Landing/Haines Junction)

Date	Community & Location	Contact Info
June 24	Faro Valley B&B – 2 Rooms	994-2122
June 25/26	Carmacks Mukluk B&B – 2 Rooms	863-5232
June 29	Haines Junction Alcan Motor Inn – 2 Rooms	634-2371

Team 2
Wendy Scramstad & Dwight Redden/Jay Massie

Date	Community & Location	Contact Info
June 24	Dawson City 1 Room Eldorado, 2 Rooms Yukon Hotel (024125,024126,024127) Need 48 hour notice to cancel	993-5451
June 27	Teslin Yukon Motel (Rooms 13 & 14)	390-2575
June 28	Watson Lake A Nice Motel (YU1F086518)	536-7222

Cakes

Date	Community	Items Needed	Retailer	Date of Pick Up	Ordered	Contact #
Team One						
June 24th	Faro	4 cakes for aprox 50 people	Mrs. Boyle	110626	yes	
June 25th	Ross River	4 cakes for aprox 50 people	Tatchun General Store Carmacks open 7-11		yes pick up NOON	1 867 863 6171
June 26th	Pelly Crossing	4 cakes for aprox 50 people	Selkirk Centre Pelly		yes pick up NOON	1 867 537 3031
June 27th	Carmacks	4 cakes for aprox 50 people	Tatchun General Store Carmacks open 7-11		yes pick up NOON	1 867 863 6171
June 29th	Burwash Landing	6 cakes for aprox 50 people	Madleys		yes pick up NOON	1 867 863 2200
June 30th	Haines Junction	8 cakes for aprox 80 people	Madleys		yes pick up NOON	1 867 634 2200
Team Two						
June 25th	Dawson City	3 cakes for aprox 50 people	Dawson General Store		yes pick up NOON	1 867 993 5475
June 27th	Teslin	2 cakes for aprox 50 people	Superstore - Whitehorse		yes pick up 8:30am	456 6618
June 28th	Watson Lake	2 cakes for aprox 100 people	Watson Lake Foods		yes pick up NOON	1 867 536 2250

One Change Marketing

- 8000 Energy Kits
- t-shirts, volunteers - Short sleeve, quality cotton navy shirts. With subtle One Change embroidered (in white) logo on front and silkscreened logos, in white on back - please see "tshirt_final.pdf" for approval
- Light-weight jacket and golf shirts, champions and One Change staff. Olympic blue with subtle One Change embroidered (white) logo on front and heat transfer (white) on back, of three logos horizontally across the shoulder area - please see "golfshirt_horizontal_10in_final.pdf" for approval
- Golf shirt - navy, 100 wicking fabric with classic flat knit collar with subtle One Change embroidered (white) logo on front and heat transfer (white) on back, of three logos horizontally across the shoulder area - please see "golfshirt_horizontal_10in_final.pdf" for approval
- Tote - As mentioned the totes will be white with lime/green (green bottom band and carrying straps). The totes will be printed on both sides, logos all together on one side and the One Change mission statement on the other - please see "totebag_final_2.pdf" for approval.

Media Buy (YEC placing radio and facebook orders)

	June 15	June 17	June 22	June 24	June 29
Yukon News	**½ page $347.26**	**½ page $370.19**	**½ page $347.26**	**½ page $370.19**	**½ page $347.26**

Klondike Sun	**½ page $375.00**				
Radio	**Starts June 20 and runs through campaign (CKRW and CHON)**				
Facebook	**Starts June 20 and runs through campaign**				

Radio Scripts

- Version 1: Announcing the One Change campaign coming to communities across the Yukon.
- Version 2: Announcing the One Change campaign presents at the Canada Day celebrations in Whitehorse on July 1.

Signage

- Horizontal banner - (to be used at events to be hung from the tents) For placement on rear wind-wall of pop up canvas top tent. *One of horizontal banner or roll up banners to promote the prize give away (confirmed as a Whirlpool Energy Star® flat 22' fridge with pull out freezer drawer, to be provide by Whirlpool and supplied by Now Appliance & Bedding).*
- Roll-up banners - To be used at events and outside room for small meetings – showcase the campaign and sponsoring partners' logos
- Poster (to be used in the communities to help promote events) Posters announcing the details of the community events (time, date, location) to be sent to each Champion for distribution around communities as appropriate
- Podium sign (to be used at meetings as appropriate)
- Vehicle side and back wrap (to be use on the cube van that will travel from Whitehorse and back)

Additional Materials

- Hand crank display back board - Think grade 8 science fair table top exhibit to "test your human power" in the main panel and some stats and figures and partner logos on the two side panels
- Hand crank stickers - Update to be One Change branding. Simple designs.
- One change tri-fold mini brochures - To be used at events and outside room for small meetings – showcase the campaign and sponsoring partners' logos

UTILITIES CONSUMERS' GROUP

DEMAND SIDE MANAGEMENT PRESENTATION

The Canadian Institute of Wellbeing uses the concept of social inclusion when considering community vitality, one of the eight domains of the Canadian Wellness Index. The Index, which is currently under development, is a multi-faceted measure of the well-being of Canadian society.

> "A social inclusion framework focuses attention on the differential life experiences of all citizens within a community and in so doing, highlights the need to remove barriers to equal participation, free from discrimination. A socially inclusive society is thus one that develops the talents and capacities of all members, promotes inclusive participation in all walks of life, actively combats individual and systemic discrimination, and provides valued recognition to groups such as ethno-racial communities." (*Community Vitality: A Report of the Institute of Wellbeing*, 2009; p. 29)

A socially inclusive society is therefore one which cultivates the skills and abilities of its citizens and communities, and works towards a goal of equal opportunity and freedom from discrimination.

"I'm gonna pay my electricity bill while I'm here."

GOALS

- LOWER BILLS FOR ALL PARTICIPATING CONSUMERS
- ELIMINATE BARRIERS SO ALL RESIDIENTIAL CONSUMERS CAN ACCESS ENERGY CONSERVATION MEASURES
- PROMOTE LOWER COSTS THAN ALTERNATIVE ENERGY SUPPLY
- PRODUCE SYSTEM BENEFITS INCLUDING THE AVOIDED COSTS OF NEW GENERATION AND THE LOWERING OF EMISSIONS
- ROLES FOR ALL STAKEHOLDERS MUST BE CLEARLY IDENTIFIED (I.E. GOVERNMENT- ENERGY SOLUTIONS CENTRE, YUKON HOUSING CORPORATION, ENERGY MINES AND RESOURCES); UTILITIES-YUKON ENERGY AND YUKON ELECTRICAL; RATPAYERS/CONSUMERS; REGULATOR

LOWER BILLS FOR PARTICIPATING CONSUMERS

- ALL RATEPAYER GROUPS MUST BE INCLUDED IN DEVELOPING DSM PROGRAMS
- ALL RESIDENTIAL RATPAYERS MUST BE ENFRANCHISED TO PARTICIPATE IN SUCH PROGRAMS
- TARGETTED PROGRAMS WILL BE NECESSARY WITH NO EXCUSES THIS TIME

households living in poverty. The LICOs used for this report are as follows:

2005 after-tax LICOs, for urban areas with less than 30,000 people

Size of family unit	After-tax household income, 2005
1 person	12,899
2 people	15,700
3 people	19,548
4 people	24,388
5 people	27,772
6 people	30,799
7 or more people	33,827

Source: Statistics Canada, Catalogue No. 75F0002M

The following table provides a useful comparison for identifying family types that are more likely than others to experience severe poverty. Lone-parent families stand out, as they are more likely to be in severe poverty than other Yukon families.

Yukon households living below the low-income cutoff (LICO) in 2005

	Total households	Economic families in low income	
		Number	Percent
Total — All economic families	8,300	360	4.3%
Couple economic families	6,510	205	3.1%
Couples only	2,900	105	3.6%
Couples with children	3,300	100	3.0%
Couples with other relatives	305	10	3.3%
Lone-parent economic families	1,620	150	9.3%
Male lone-parent families	390	35	9.0%
Female lone-parent families	1,100	115	10.5%
Other economic families	170	0	0.0%

Source: 2006 Census

LOWER COSTS TO UTILITIES

- EACH DEVELOPED PROGRAM MUST ACHIEVE LOWER COSTS THAN ANY ALTERNATIVE SUPPLY OPTION
- EACH PROGRAM MUST BE EVALUATED ON A REGULAR BASIS (BI-YEARLY?)
- DSM PROGRAMS MUST NOT DRIVE INCREASED RATES

ROLES OF GOVERNMENT

1. ENERGY SOLUTIONS CENTER

A. DEVELOP TARGETTED PROGRAMS FOR MARGINALIZED CONSUMERS AND RENTERS USING GOVERNMENT FUNDS

B. DEVELOP CERTAIN PROGRAMS WITH HANDS ON INVOLVMENT USING GOVERNMENT FUNDS (I.E. RESIDENTIAL IN HOUSE STRATEGIES SUCH AS HOT WATER TANK TIMERS AND BLANKETS, LIGHTING ALTERNATIVES, ETC.

2. YUKON HOUSING CORPORATION

A. DEVELOP RETROFIT PROGRAMS FOR MARGINALIZED HOUSEHOLDS AND LANDLORDS USING GOVERNMENT FUNDS

B. DEVELOP NON-INTEREST LOANS FOR RESIDENTIAL RETROFITS TO MARGINALIZED FAMILY HOUSEHOLDS AND LANDLORDS WITH CONDITIONS

3. GOVERNMENT DEPARTMENT ENERGY, MINES AND RESOURCES

A. PROVIDE FUNDING FOR ESC AND YHC PROGRAMS FOR MARGINALIZED, RENTERS, AND LANDLORDS

B. DEVELOP STRATEGY FOR ALTERNATIVE SUPPLY IN DIESEL COMMUNITIES

C. COMPLETE POLICIES FOR IPP, NUGs AND NET METERING

D. NO FURTHER LEGISLATION REGARDING BUILDING DESIGN EITHER BY YTG NOR THE CITY.

THE UTILITIES-YEC AND YECL

- OFFER MAINSTREAM RESIDENTIAL DSM PROGRAMS
- DEVELOP DSM TECHNIQUES/PROGRAMS FOR GOVERNMENT, MUNICIPALITIES, COMMUNITIES, FIRST NATIONS, LARGER GENERAL SERVICE, MINES, ETC.
- INITIATE MORE EFFICIENT LOAD MANAGEMENT, DEMAND RESPONSE, DISTRIBUTION SYTEM OPTIMIZATION AND FUEL SWITCHING TECHNIQUES
- DEVELOP TIME OF USE RATES (I.E. SEASONAL)
- DEVELOP RATE DESIGN TO ENCOURAGE LESS USAGE (AFTER DSM PROGRAMS ARE IMPLEMENTED AND IN USE)

THE REGULATOR-YUKON UTILITIES BOARD

- TO ENSURE EACH DSM PROGRAM BENEFITS THE CONSUMER
- TO ENSURE THE PROGRAMS ARE COST EFFECTIVE WITH REGULAR MONITORING TO DEMONSTRATE EACH PROGRAM IS PRODUCING EXPECTED BENEFITS
- TO ENSURE ADEQUATE EVALUATION TECHNIQUES ARE ADDED TO THE FORMULA
- TO SET APPROPRIATE LEVELS OF DSM SPENDING
- TO OVERSEE COST RECOVERY AND INCENTIVES FOR EACH DSM PROGRAM

OTHER STAKEHOLDERS

- TO BE INVOLVED IN ALL ASPECTS OF DEVELOPING AND EVALUATING DSM PROGRAMS, INCLUDING LARGER CUSTOMERS SUCH AS MUNICIPALITIES AND MINES
- TO BE INVOLVED IN THE DESIGN, IMPLEMENTATION AND EVALUATION OF ALL DSM PROGRAMS, INCLUDING THE MINES
- TO HELP INFORM AND EDUCATE THE PUBLIC

Building a Culture of Conservation

beyond the utilities

Anne Middler, Energy Coordinator, Yukon Conservation Society

Yukon Conservation Society

April 19, 2012

Demand Side Management (DSM) What are we talking about? Why?

CONSERVATION = consuming/using LESS

EFFICIENCY = using BETTER/SMARTER

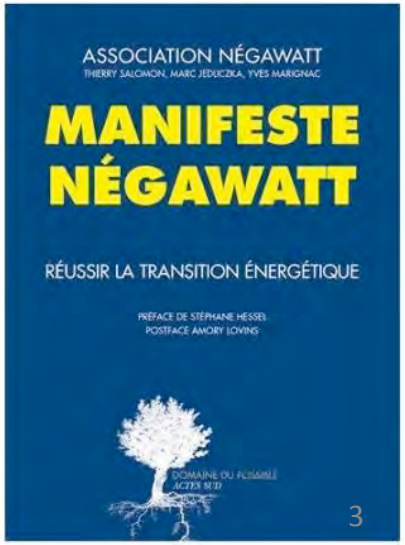
All sources of energy (even “green”) have impacts.

The best solution – reduce our demand for energy and use of resources.

negawatt…. negawhat?

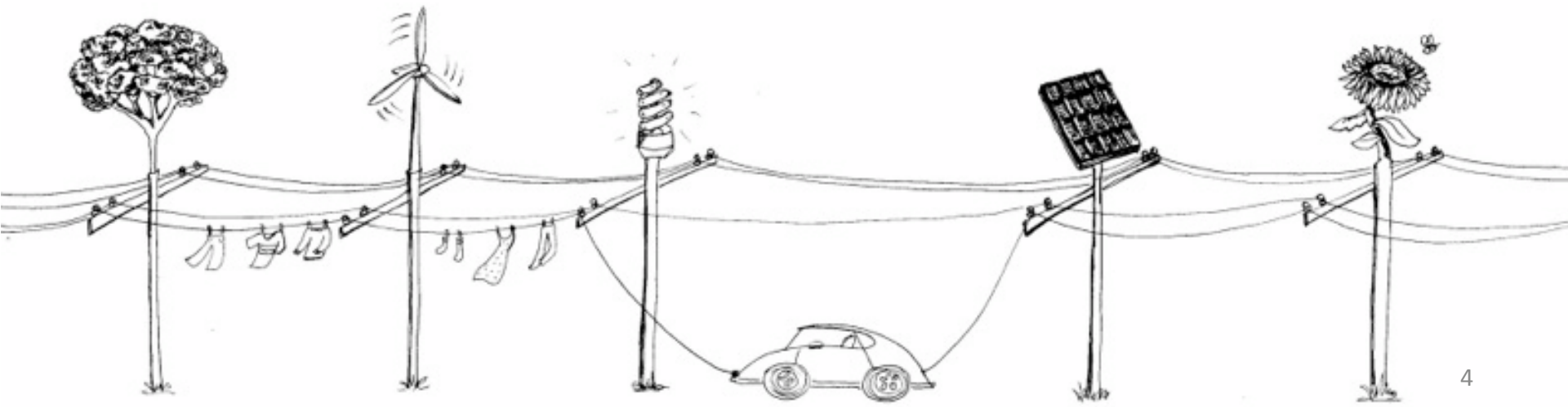
- Negawatt is a theoretical unit of power representing the amount of energy saved.
- The conserved energy is a negawatt, **the measure of power that is not used.**
- For example, Earth Hour.

Negawatt Media



NEGAWATTS before MEGAWATTS

- Meet growing demand through DSM before new infrastructure
- Implement all strategies for reducing waste of energy regardless of perceived economics (YUB requirement)
- Let's aim for the technical potential, not just economic or achievable.
- If ratepayers don't pay for DSM programs, Government has to.
- Combination of stick and carrot (currently, more stick needed)



GOVERNMENT role and responsibility versus UTILITIES

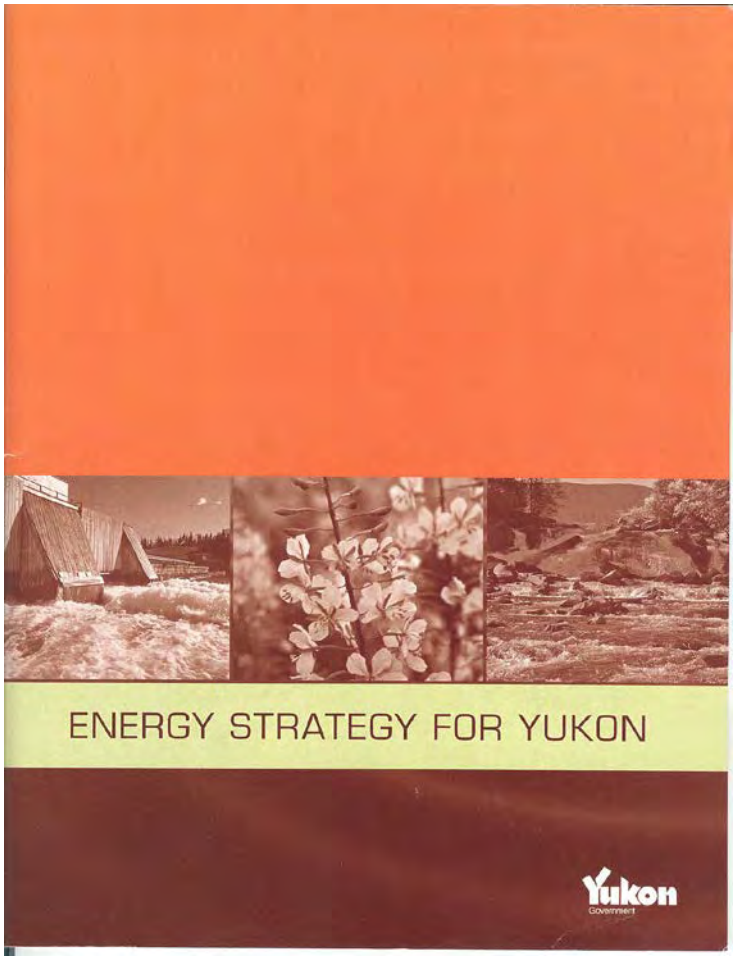
Utilities – directed by Yukon Utilites Board to investigate/implement DSM, but should DSM be led by utilities?

- …. seems counterintuitive for businesses to want to spend money to sell less and earn less money.

but the Yukon Government on the other hand…

- Energy Strategy for Yukon
- Climate Change Action Plan

Energy Strategy for Yukon



NUMBER ONE:

EFFICIENCY and CONSERVATION (E&C)

Goal

Energy efficiency and conservation will be a priority to reduce energy consumption, energy costs and emissions.

- Develop policies for E&C
- Deliver programs for E&C
- Incorporate E&C into decisions
- Improve E&C in communities
- Incentives for building retrofits
- Promote efficiency in new buildings
- Make industry more energy efficient

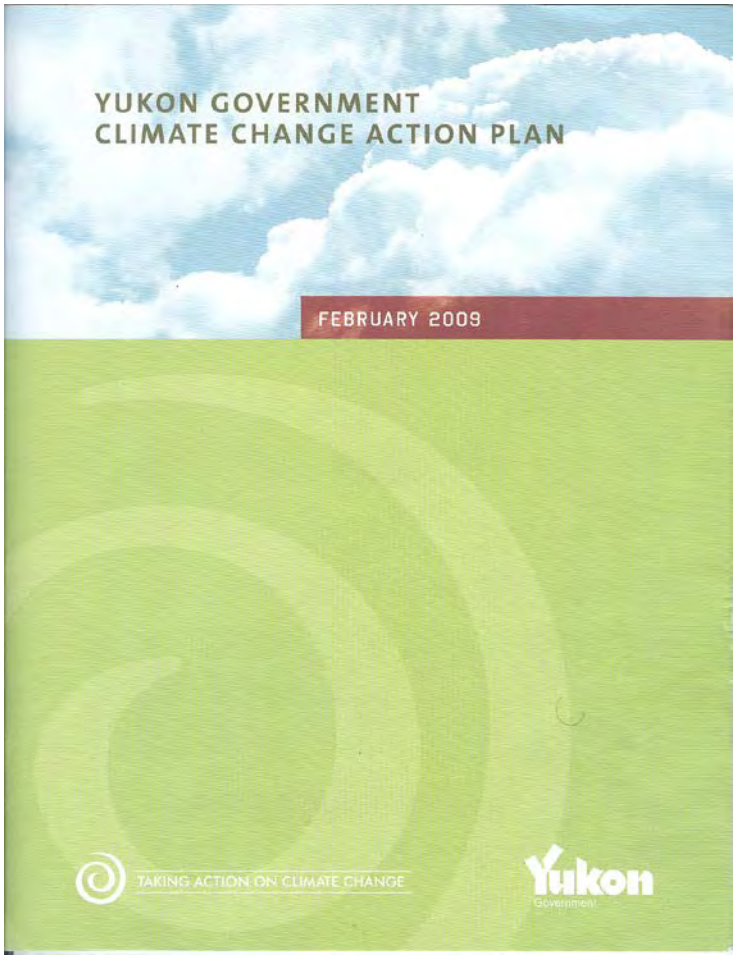
Climate Change Action Plan

Goal 3:
REDUCE OUR GREENHOUSE GAS EMISSIONS

Lead Yukon Action in Response to Climate Change

• Yukon Government operations to be carbon neutral by 2020.

• Emissions Targets – "…develop a Yukon-wide reduction approach."
• The target will be developed in a manner that shows our commitment to reducing our contribution to climate change…



Build a Culture of Conservation

- Individual/household behavioral change (not only to encourage a reduction in use of electrical energy, but all consumption of energy and resources (water, driving, buying etc.)

2011 Energy Diet Challenge Champions, the Kitchen-Kuiack family.

Shell-Canadian Geographic

Smart Meters – the power to save

- Empower individual and household consumers to manage their energy use and make smart choices.
- Start with a pilot project for interested people, monitor, publish results, implement broadly.

Price Signals – (stick!)

- Once people have a better understanding of their consumption, price signals can reduce/shift demand and recompense for the costs of producing more electricity.
- Ontario, Nova Scotia, have **time of use (TOU)** rates in place (costs more/pay a premium to use electricity in peak times, cheaper to consume off-peak)

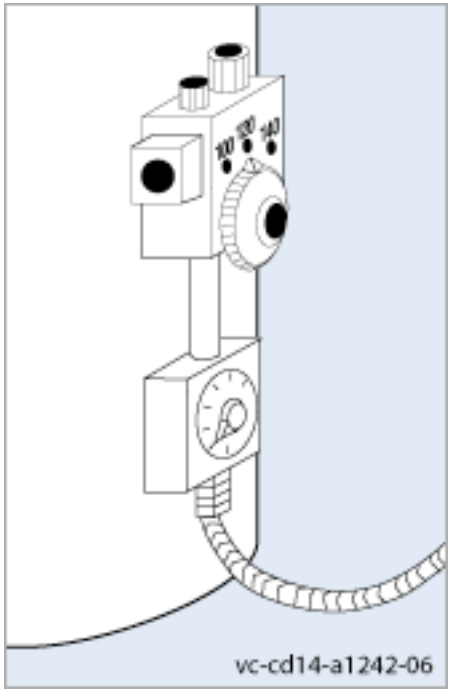
off-grid diesel communities

- overhaul Rate Structure to encourage renewables
- ramp up all DSM programming

Old Crow Research Facility photo Kobayashi and Zedda Architects

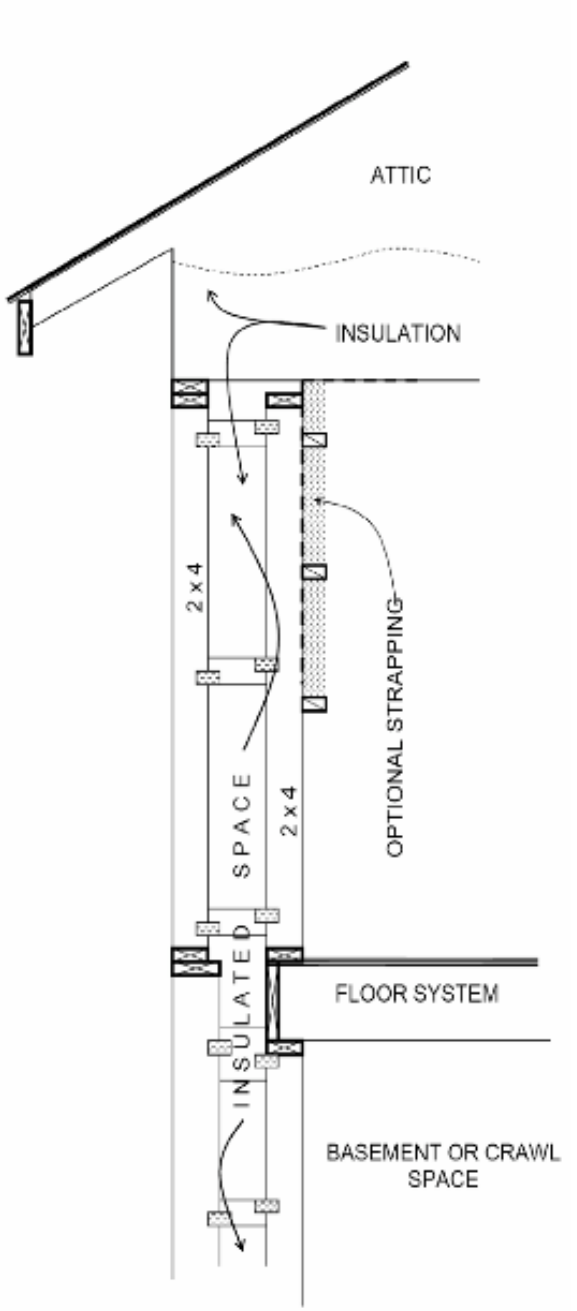
Demand Shift – leveling the peaks

In 2002, Yukon Development Corporation completed a successful pilot program on hot water tank timers ("penguins").

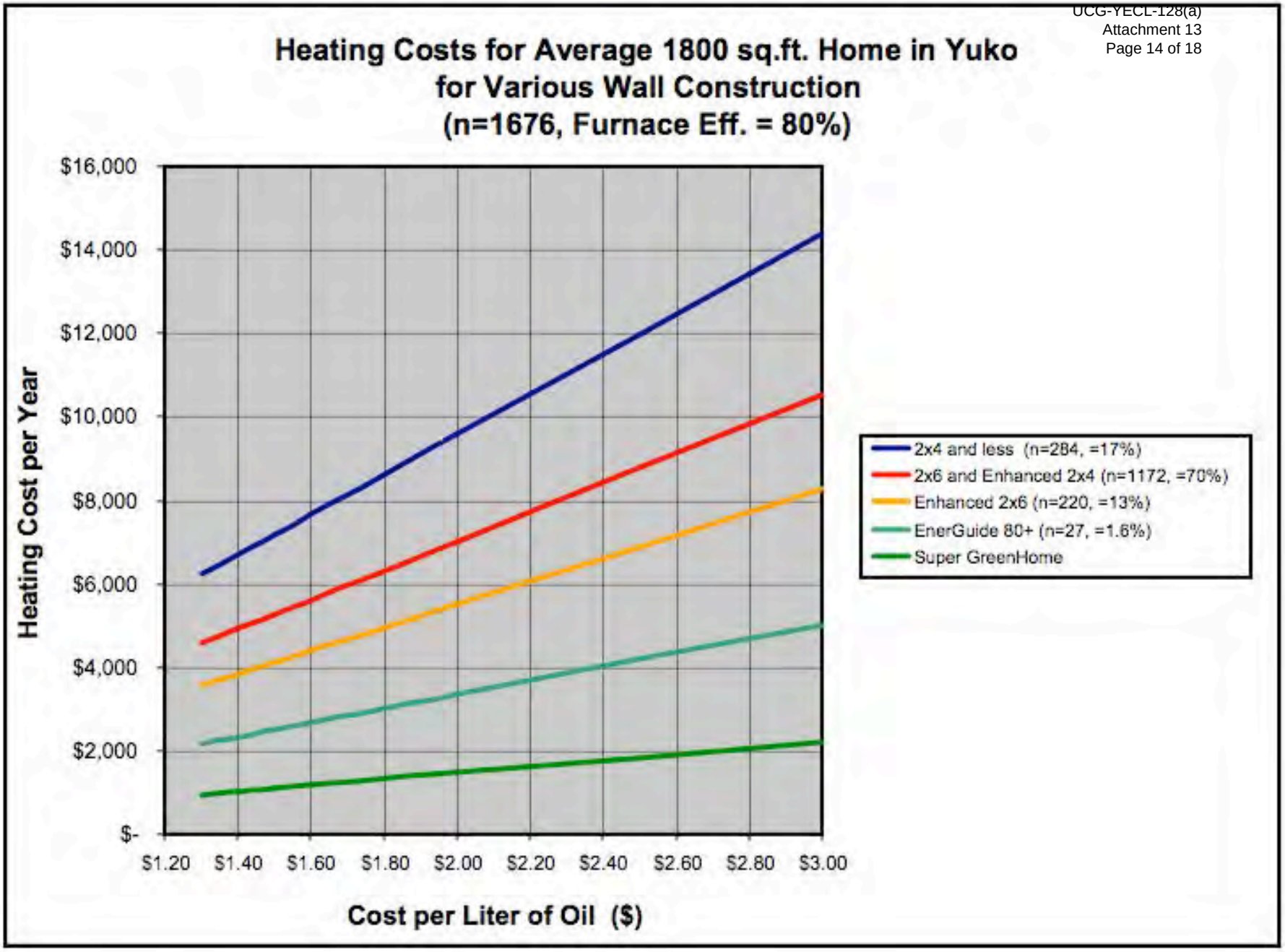


Strengthen Building Codes

– and serious investment in improving existing buildings



- Superinsulation (supergreen, doublewall) for comfort and safety
- Heat Recovery Ventilators (HRV) for healthy homes
- Retrofit existing building stock for safety and efficiency
- Improved code should allow for alternative construction and local materials, but restrictions for electric heat unless demonstrated efficiency


Heating Costs for Average 1800 sq.ft. Home in Yuko
for Various Wall Construction
(n=1676, Furnace Eff. = 80%)
Heating Cost per Year
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$-
$1.20
$1.40
$1.60
$1.80
$2.00
$2.20
$2.40
$2.60
$2.80
$3.00
Cost per Liter of Oil ($)
2x4 and less (n=284, =17%)
2x6 and Enhanced 2x4 (n=1172, =70%)
Enhanced 2x6 (n=220, =13%)
EnerGuide 80+ (n=27, =1.6%)
Super GreenHome

Industrial Demand Management

- Required energy audits/improvement for all existing and proposed mines
- Rate structure for power down incentive (peak and winter rates)
- Cost of Service (mines pay more than it costs to serve them? Really? Hmm.)
- Obligation to Serve (we *have* to serve them? Really? Hmm.)

Faro Pit and Rose Valley Tailings at the Faro Mine.

Supply Side to encourage conservation

NET-METERING help consumers become producers of green electricity (premium rates for export after household use of produced power)

Riverdale Net-Zero House in Edmonton

etcetera

- Commercial, Institutional, Industrial, Government.
- Net Metering/IPP/overbuild renewables to enable fuel switching (reduce emissions from transportation and space heating)
- Street lights, lighting, hot water, etc
- STORAGE/load management: batteries, heat sinks, heat recovery systems, Electrical Thermal Storage (ETS)
- Alternative heat (to oil or electricity) via district heating, ground/air source heat pumps
- cogeneration
- PUBLIC EDUCATION

THANK YOU

Yukon Conservation Society

Yukon Energy Charrette – March 7 – 9, 2011

The following notes do not represent a comprehensive "capture" of all that was discussed at the charrette, but are merely a compilation of the raw notes gathered during the event. A more complete and formal report will be available by late April.

Day 1 – Day Session

Identifying the Problem (issues, assumptions, restraints):

-We are running out of clean, affordable energy and we don't have a lot of time. Whole issue of energy security. This is a significant problem that is relevant to all of us.

-Status quo is not sustainable in meeting Yukon's energy needs.

-Growing population. Consumption is increasing.

-Isolated grid

-Economic growth: people, consumption, industry, transfers

-Environmental consequences

-Infrastructure is aging.

-Utilities need to be more efficient – load management and peak management

-There are some critical decisions to make in terms of energy future. Facing tough choices.

-We need/want more electricity without using diesel, without paying/risking a lot of money on renewables, and we should all use less/not be wasteful.

-meeting economic development goals

-uncertainties about how much generation is needed (unpredictable demand). We cannot predict the future. Highly variable.

-What are we willing to pay? We are not paying the true cost of power right now. We need a clear price signal. Low energy costs result in waste.

-Regulatory structure doesn't reward Demand Side Management (energy conservation)

-Need mechanism for Independent Power Producers.

-lack of winter energy. Power most needed in winter, when we have least amount of hydro.

-issue of rightsizing capacity/scalable

-boom and bust versus consistent growth.

-How do we mitigate risk of boom and bust economy?

-isolated grid, 2 utilities (small jurisdiction), small ratebase

-greenhouse gas emissions, climate change, peak oil

-can't always wait for business case

-peak demand; variability of demand

-expensive diesel generation – have to generate more power using diesel

-non-sustainable generation (diesel)

-meeting peak demand in winter

-limited short-term solutions to meet growing demand

-lack of certainty regarding long-term economic/load growth (lack of long term vision/planning) and uncertainty regarding climate change and hydrology

-The era of surplus is ending and a mining boom is underway.

-Is the issue an energy one or a social one (perhaps solution is behavioural and we can learn from the past)?

-Yukon Energy feels some obligation to supply new mines. Issue of Orders-in-Council and the Obligation to Serve. Issue of government policy.

-Question about mines: who bears the risk? Rates to mines should reflect the risk to Yukoners (price shock when mines shut down). Mines should be treated differently in terms of rates. To serve or not to serve mines is an issue that needs to be addressed. Many, many questions about who's responsibility it should be to provide power to mines. Clarify mandate of Yukon Energy.

-need to replace the attributes of diesel. However green doesn't seem feasible when we have diesel that works.

-need a mix that is flexible

-consider transition technology

-need about 100 gigawatt hours per year of clean power

-Electrical energy is becoming more popular.

-Consider ramping up biodiesel from trees.

-Will need to replace aging generators

-Expensive energy lowers our standard of living; social justice implications of expensive energy. Support people who are vulnerable.

-Affluent people don't mind if rates go up, but it's a problem for the less affluent.

-Rate inequality.

-There's a lack of transparency about costs and who pays.

-Seasonal challenges.

-There is a lack of consumer input because of a complicated regulatory language and process.

-Confusing regulatory structure; problem with accessibility of issues and process. Rate issue is complete and there is no consensus on this issue.

-Very complex and intertwined issues

-We don't clearly understand the non-mine load growth.

-Even without mines we soon will reach our limit of being able to supply Yukoners with electricity using existing renewable sources.

-Public education gap/need for broad public education and engagement

-Lack of common language based on facts – hard to have positive, informed dialogue with the public to build consensus

-People want to be part of the solutions but they don't know what to do.

-Lifestyle choices (energy hogs). Consumption is moving in the wrong direction (up). There is a culture of energy entitlement. Explosion of electronic devices, ghost loads, etc. Need to encourage energy efficiency (energy efficient appliances, etc.)

-Smart Meters are a must.

-Whitehorse is not a well planned community in terms of being able to use the least amount of energy possible.

-Different opinions on right/wrong decisions

-Need to focus on energy and not just electricity.

-Are we technologically ready for some choices (ex. electric cars)?

-IPP can be in competition with utilities; length of contract an issue

-use hydro as peak power and use solar with baseload

-new hydro issues: flooding First Nations land used for hunting and gathering

-must develop partnerships with First Nations and mines

What do we want Yukon's energy future to look like (what is the vision)? What are the opportunities and solutions?

Attributes of any energy choice should be:

1) **Affordability:**

-equity

-fairness/socially responsible

-good for Yukon

-Not necessarily the cheapest

-Can't have rate shock (anything above 15 percent per year).

-economically responsible

-per capita; family fair consumption

-use energy to build community prosperity

-true cost of power vs. affordability. Linked to government policy.

-small business – affordability and reliability are the main issues

-challenge of shared responsibility

-Need block rate structures to send energy conservation signal

-Must balance being equitable among customer classes with conservation.

-Rate design: need trade-offs.

-Obligation to serve at what price? Should the mines pay the full cost for their electricity?

-Real cost of energy opens door to discussion about fairness of rates

2) Reliability:

-Boom and bust economic...need to plan for that.

-Security of supply of fossil fuels unknown.

-Competing interests: how to balance/choose/find win-wins. Must balance interests.

-need predictable cost

-need capital/operating cost ratio that makes sense

-further investigate trans-border energy links with B.C. and/or Alaska.

-reliable in both winter and summer

-use renewable to provide baseload energy

-Mines should continue to be asked to subsidize infrastructure.

-speed to market

3) Flexibility:

-limit/show growth of change: is this under our control?

-Any short term goals must lead to long term solutions.

-any solution needs to be accepted by the Yukon public.

-assets should be built with future needs in mind (ex: Carmacks-Stewart transmission line should have been built bigger)

-There needs to be a greater generation mix. Must diversify.

-Yukon Energy needs to go beyond electricity and be more about energy; should get into district heating.

-Need to be open and flexible for emerging technologies.

-Coordinate with other initiatives.

-Power sources must be incremental.

-diverse suppliers model

4) Locally maintainable

-vertical integration using local resources

-need to consider limits to growth

-Does it improve economics in Yukon? Needs to support economic development.

-technical limits/skills

-technology available on a suitable scale?

-leadership in technology, Demand Side Management (energy conservation), innovation, policy, etc.

-Provide access for small energy producers to contribute to the system.

5) Environmentally responsible (clean?)

-Why diesel is not a good choice: greenhouse gas emissions, security of supply, cost (price fluctuates)

-meet needs sustainably, but people have to recognize and explicitly acknowledge that there will be tradeoffs against competing interests (i.e., new generation facilities will have to be built because Demand Side Management - conservation and efficiency - won't meet all the demand)

-need to look at life time costs of projects when determining if they are clean or green (cradle to grave)

-opportunity to look at green building codes for Whistle Bend, spruce bark beetle district heat, carbon neutral

-look at total Yukon greenhouse gas reductions.

-don't just look at greenhouse gas emissions. There are other costs that you can't put a dollar value on.

-We need to move away from fossil fuels and we need to reduce our carbon footprint. Need to consider footprint size in whatever Yukon Energy does

-All Yukoners need to take personal responsibility for their energy usage. Small changes embraced by many can make a big difference. We should all be less wasteful.

-I want to feel I am doing something to help the environment.

-More 'stick' and less 'carrot'. Emphasize individual responsibility.

-We need to send price signals that will lead to energy conservation.

-We need to be super green.

-Demand Side Management ideas such as hot water heaters in homes controlled by Yukon Energy; interruptible electric heat

-Yukon Energy needs to develop more renewable energy.

-Smart Metering

-Offer programs for heat pumps.

-Award people for efficient use of energy.

Day 1 – Evening Session

Comments from the public on the work done by charrette participants on Day 1:

-Whatever choices are made need to be flexible and scalable.

-There needs to be a consistent strategy

-There is an opportunity to replace diesel with renewable

-Must figure out the solutions

-We need to know the true cost of electricity. (We don't pay true cost but we also don't pay the true cost of oil).

-What is the breakdown in electricity supply?

-Opportunity to meet greenhouse gas emissions targets

-Good process. Glad Yukon Energy is doing this.

-Make money off distributed generation (i.e. solar panels on people's roofs)

-Individual systems (net metering)

-Challenge people: the solution is low hanging fruit (energy conservation)

-Look at the big picture

-People are too concerned about the past decisions and not the future ones.

-Twenty to thirty year solution: Atlin, Gladstone, Marsh.

-Who profits from rate increases?

-How long does it take to build new generation of various sizes?

-Let Western Copper build/provide their own power (liquefied natural gas) and then Yukon Energy could buy some of it for other Yukoners

-Should public be aware of rate plan changes when fossil fuel heat is more expensive than electricity?

-Information to the public needs to be clear

-In terms of decision making criteria, consider the following additional things: 1) innovation; 2) politically independent; 3) local; 4) scientifically objective; 5) incent economic and resource development; 6) local economy benefit/create community revenue stream and jobs; 7) research new technologies/innovation for cold climates and include research and development centre; 8) synergies with other systems i.e. southeast Alaska/BC Hydro

Day 2 – Day Session

Playing the Energy Game (alternatives and consequences of choices):

Scenario: the existing energy generation with hydro is 400 GWh/yr. Groups were asked to find new energy for 2015 (additional 144 GWh/yr), 2025 (additional 273 GWh/yr), and 2050 (additional 650 GWh/yr). Participants were to base their choices on the general criteria of affordability, reliability, flexibility, and environmentally responsible. A possible 5th consideration would be "Is it local?"

Choices, in order of preference:

2015:

-Hydro Enhancement (Marsh Lake)

-Demand Side Management

-Wind

-Biomass

-Hydro Enhancement (Atlin Lake)

-Hydro Enhancement (Gladstone)

-Liquefied Natural Gas

-Solar

-Waste to energy

-Diesel enhancement

-Individual district generation

-On site generation at large mines from pipeline

2025:

-Solar and wind (tied for first place)

-Liquefied Natural Gas

-biomass, medium sized hydro and Demand Side Management (tied)

-geothermal

-small hydro/hydro enhancements and micro-nuclear (tied)

-vehicle battery and waste to energy (tied)

-Connection to BC grid

-spinning reserve, Independent Power Producers, and large hydro (tied)

2050:

-solar and new hydro (tied)

-Demand Side Management, connected to grid, liquefied natural gas (pipeline), biomass (tied)

-nuclear, new technologies, geothermal and electric transportation (tied)

Day 2 – Evening Session

Dot-mocracy Game: members of the public were invited to make their choices as to energy options for 2025 and to vote for their choices using "dots" with 1 dot = 1 vote.

Results of game, in order of preference:

-Demand Side Management/energy conservation (43 votes)

-biomass (40 votes)

-wind (35 votes) <21 votes for Ferry Hill and 14 votes for Mount Sumanik>

-new hydro medium-scale (31 votes)

-nuclear (24 votes)

-solar (23 votes)

-geothermal (15 votes)

-transmission: B.C. or Alaska (15 votes)

-Marsh Lake storage (13 votes)

-New Hydro – small scale (13 votes)

-Atlin storage (12 votes)

-waste to energy (7 votes)

-Gladstone diversion (5 votes)

-natural gas (5 votes) <on site generation 3 votes and conversion 2 votes>

After using dot stickers to choose favoured options, here are some general observations from members of the public who participated in the game:

-There were no real micro options (options for individual homes).

-Nuclear didn't make the list, but it really should have. It is practical. It works.

-We needed to know the cost per kilowatt hour (dollar signs tried to show that but they weren't all that helpful).

-Demand Side Management (energy conservation) is a no-brainer because it's part of the immediate solution.

-A number of people were looking for synergy between systems when they were making their choices.

-A number of people voted with two to four stickers on each of several options. Only a few put five or more stickers on any one option. Only a few put just one sticker on any one option.

-Would like to see Yukon Energy using Smart Meters

-Yukon Energy should look at time of day and time of year when considering Demand Management (ex: mines should be cut off from the grid in the winter)

-Biomass provides ready employment and is carbon neutral, clean and sustainable (long term).

-There should have been an option for small micro-generation (customer owned) or co-generation for residential, business and institutions.

Day 3 – Day Session

Principles of decision-making:

-All options less per kilowatt hour than diesel

-All options must ensure reliability, flexibility, environmental responsibility, affordable

-Independent Power Producer options should be considered

-Alternative/local generation should be considered

Risks of Decisions

-Planning dollars

-Yukon Utilities Board

-Government legislation (Orders in Council)

-Energy security

How should Yukon Energy engage with the public from this point forward?

-Make public the specific principles of decision making and promote the four objectives (reliable, affordable, environmentally responsible, and flexible)

-Consolidate charrette outcomes into a summary report that is shared with the public.

-Propose your suggested energy portfolios within six months or less.

-Help people understand how the on-going engagement process will direct Yukon Energy's decision making. Report back one month out, two months out, six months out, etc.

-Show that the charrette has teeth.

-Promote public ownerhip. Show what mileposts were established at the charrette and providing periodic reporting and progress reports to show results. Accountability.

-Repeat charrettes with more emphasis on getting public out and help people feel they can make a difference.

-Provide detailed economic analysis about suggested options: help us understand how you come to the conclusions you will read in the 20-year resource plan

-Bring draft resource plan to a public meeting

-Provide Yukoners with regular updates on the process

-One day a year information sessions

-Major outreach every second year (on a week-end when it is convenient for more people)

-There needs to be broad engagement: youth, industry, First Nations, public, stakeholders, etc. Partners could include Energy Solution Centre, Yukon College, Yukon Conservation Society, municipalities, schools, retailers, non-government organizations, Yukon Housing (building standards), etc.

-Create a working group to hash out changes; create an energy working group of local people including various stakeholders and members of the general public to continue working on these issues with Yukon Energy. This group would be led by Yukon Energy.

-Yukon Energy involvement with schools, but also get the students involved in the planning.

-Presentations in every school

-Energy parade

-Maybe the MAD (Music, Art and Drama) students at Wood Street school could create an art piece that promotes energy conservation (work with the Experiential Science class) on this.

-School credits for doing energy related assignment

-paid ambassadors

-scholarships

-fix up schools

-Hold competitions among the general public re: energy use and energy conservation.

-Turn every consumer into a producer of energy

-mail out dot-mocracy so others can vote

-mail out a false high bill to shock people and get them talking

-tours of dams

-brief email updates

-need to help people over come apathy; turn off the power should be their first choice

-Build trust, continued dialogue.

-People need to see action now, based on what Yukon Energy heard at this charrette.

-Make an energy video game like SIM City.

-Smart phone app to provide information about energy consumption. Could show what sources we are using at any given time (hydro, diesel, etc.)

-Develop visual representations of energy information.

-hold 'brown bag lunch' sessions.

-Public needs to be engaged and better educated about energy issues. In particular, there needs to be better communication from Yukon Energy and Yukon Electrical Company Limited with regards to energy conservation.

-People need to understand that energy issues are important to everyone and affect everyone.

-Public meetings in more communities

-Immediate action on Demand Side Management

-Yukon Energy could empower people to take charge/control of their energy consumption (be the change).

-Work with landlords and tenants to look at creative financing in order to implement Demand Side Management (energy efficient appliances, building attributes and designs like windows, doors and retrofits)

-More school and office Demand Side Management programs

-Communicate directly with individual companies and employees about energy conservation.

-Use the charrette participants to communicate what was learned here...everyone should tell two or more people so that the message can spread.

-Bring the Yukon government to the table as leader of the multi-stakeholder group. Also bring large clients/mines into the conversation.

-Get ideas from other jurisdictions

-Make the information relevant and real for youth

-Train students who can then present information to other students (skill development). Provide cash incentives to schools based on student work. Ambassadors – informed 'audits' with student swat teams.

-In school energy fair

-Put information on bills telling people what they would be paying if they were charged the true cost of providing them with power

-"Power Nut" super hero

-Need fun projects to educate the public

-Get parents talking to kids and kids talking to parents about energy issues

-Public meetings: tap into existing meetings (partnerships)

-Pick visible, relevant wedge (ex: 'schools are energy hogs') to focus public engagement, training, public relations. This also have the effect of getting youth involved.

-Select action –oriented project to increase the public's knowledge about energy and energy conservation (ex. school audits, door to door campaigns, etc.)

-People need to have more of a basic understanding about the Yukon energy situation. They need to understand tradeoffs/rationale for decisions, and that tradeoffs are unavoidable.

-connect Yukon Energy decisions to feedback from the public (explain rationale for Corporation's choices).

-Regular section in the Yukon newspapers.

-There needs to be more advertising/public information regarding Demand Side Management.

-Solar powered bill boards telling people their energy consumption and that Yukon Energy is having to run diesel.

-Encourage change in policy and in Public Utilities Act

-Politicians need to be engaged

-website/blog, but not just social media. There is a place too for flyers, ads, etc.

-trade show

Day 3 – Evening Session

Dot-mocracy Game: members of the public were given 16 dots and asked to place them on their favourite suggestions that came from the Day 3 day session regarding how Yukon Energy should engage the public from this point forward.

Most popular suggestions:

-Partnerships: involve Yukon Housing Corporation, Energy Solutions Centre, businesses, First Nations, etc. In energy conservation programs – 19 votes

-summarize resource plan and make it readily available – 15 votes

-Produce energy-related video game like Civic Mirror or Sim City (but check first to see what already exists before developing new material) – 13 votes

-Form an energy working group made up of stakeholders and ordinary Yukoners – 12 votes

-Small but consistent communications is key – 8 votes

-provide regular and ongoing updates and opportunities for further public input – 8 votes

-Develop energy course for schools – 8 votes

-Charrette every two years – 6 votes

-let's keep talking – 5 votes

-Information needs to be visual, easy to understand, and needs to 'hit home' with people – 5 votes

-Blog/Facebook/web – 5 votes

-Solar powered sign that shows how much energy is being consumed in real time (and when we're into diesel) – 5 votes

-Fun competitions between families or between communities – 5 votes

-Convene in six months to update participants on progress – 4 votes

-Take message to other Yukon communities – 3 votes

-Electricity Day or Energy Fair – 3 votes

-Door to door DSM campaign – involve youth – 2 votes

Other suggestions that were different from what was proposed during the day session:

-Produce an annual information sheet for the fridge or cupboard that shows the cost per kilowatt hour of dryer, fridge, TVs, etc. So consumers can easily see the impact and cost of use – 2 votes

-Estimate costs and timeline for options discussed at charrette – 3 votes

-Ask consumers if electric heat is OK or decide that the seasonal load can work – 5 votes

-Consumption chart on web needs to be easy to find and read – 2 votes

-Notice to radio stations when we're burning diesel – 2 votes

-Show us how full our reservoirs are – 3 votes

Residential Workshop - November 15, 2011

Registered	Name and organization
	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Doug McLean - Energy Solutions Centre
x	James Wigmor - Energy Solutions Centre
x	Sean McKinnon - Energy Solutions Centre
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
	Hector Campbell - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Dwight Redden - YECL
	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
x	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
x	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Roy Whiten - Green Heat Technologies Ltd
x	Northerm Windows and Doors (David or Russ)
x	Wayne Wilkinson
x	Terry R-Holway (CAFN)
x	John Maissan of Leading Edge Projects
x	JP Pinard
x	Forest Pearson
x	Viviane Tessier - Remax
x	Jonathan Kolot - builder/ framer
x	Paulette Reust - Coldwell Banker
x	Karol Campbell - Coldwell Banker
x	Ray Sabo
x	Scott MacDonald - Igloo
x	Elain Whytte - Mayor of Carmacks
x	Janet Patterson - YEC
	Sow's Ear Builders and Energy
x	Yannick St-Jean - Ever Green Homes and Construction
x	Richard Corbet - Yukon Government
x	Brian - Kiwi Construction
x	Jen Meurer - Energy Mines and Resources
x	John Stricker

Commercial & Institutional Workshop - November 16, 2011

Registered	Name and organization
	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Doug McLean - Energy Solutions Centre
x	Marianne Gregoire – Highways & Public Works
	Rebecca World/ Shanna Epp – Climate Change Secretariat
	Helen Booth—Economic Development
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
x	Gord Debruyn YG
x	Hector Campbell - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Cameron Osler - Intergroup
	Dwight Redden - YECL
x	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
x	Geoff Quincy - City of Whitehorse
	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Rick Karp or Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Fraser Smith Northern Climate Engineering (NCE)
x	Jeffery Pike - NCE
x	Dylan Stewart - NCE
x	Dyson Hale - NCE
x	Roy Whiten - Green Heat Technologies Ltd
x	Northerm Windows and Doors (David and Russ)
	ArcRite Northern
x	John Maissan - Leading Edge Projects
	JP Pinard
x	Ray Sabo ESC
x	Elain Whytte - Mayor of Carmacks
	Janet Patterson - YEC
x	Rod Savoie - FSC Architects and Engineers
x	Mike Simon Property Management
x	John Stricker
x	Jen Meurer - Energy Mines and Resources

Customer-Side Renewable & Alternative Energy Workshop - November 17, 2011

Registered	Name and organization
	Shane Andre – Energy Solutions Centre
x	Manon Moreau – Energy Mines and Resources (Energy Strategy)
x	Cathy Cottrell – Energy Solutions Centre
x	Juergen Korn –Yukon Housing Corporation
x	David Black—Education
x	Krista Roske - YEC
x	Hector Campbell - YEC
	Ed Mollard - YEC
	Tom Debolt - YEC
	Mona Pollit-Smith - Intergroup
	Cameron Osler - Intergroup
x	Marc-Andre Lavigne - YEC
x	Shannon Mallory - YEC
	Dwight Redden - YECL
	Phil Borgel - YECL
x	Laura Carlson - YECL
x	Wendy Scramsted - YECL
	Geoff Quincy - City of Whitehorse
x	Shannon Clohosey - City of Whitehorse
	John Pattimore – Association of Yukon Communities
	Rick Karp or Sampson Heartland – Whitehorse Chamber of Commerce
x	Anne Middler – Yukon Conservation Society
x	Roger Rondeau – Utilities Consumer Group
x	Treharn Drury – Yukon Cold Climate Innovation Centre
x	Wayne Wilkinson
	ArcRite Northern
x	John Maissan - Leading Edge Projects
x	JP Pinard
	Jonathan Kolot - builder/ framer
x	Ray Sabo
	Janet Patterson - YEC
	Sow's Ear Builders and Energy
x	Terry R-Holway (CAFN)
	Laura Spicer -INAC
	Lawrence Ignace - INAC
x	James Wigmore ESC
x	Doug McLean ESC
x	Sean McKinnon
x	Shirley Abercrombie - Energy Mines and Resources
x	Janet Patterson - YEC
x	John Stricker

CPR Methodology Workshop (May 3, 2011) - Attendees

Morning Educational Session 8:00 am - 12:00 pm

1. Shirley Abercrombie
2. Dwight Redden
3. David Morrison / Piers McDonald
4. Shane Andre
5. Manon Moreau
6. Cathy Cottrell
7. Doug McLean
8. Marianne Gregoire
9. Rebeccal World
10. Eric Schroff
11. Helen Booth
12. Clare Robson
13. Juergen Korn
14. David Black
15. Greg Finnegan
16. Wayne Tonsi
17. Phil borgel
18. Laura Carlson
19. Wendy Scramsted
20. Krista Roske
21. Hector Campbell
22. Ed Mollard
23. Tom Debolt
24. Wesley Marsh
25. Mona Politt-Smith
26. Cameron Osler
27. Marc-Andre Lavigne
28. Janet Patterson
29. Lawrence Ignace
30. Wayne Tuck
31. Mike Gau
32. John Pattimore
33. Rick Karp
34. Mike Wark
35. Laurie MacFeeters
36. Anne Middler
37. Roger Rondeau
38. John Maisson
39. Steve Mooney
40. Arcrite Northern
41. Archtech Ventillation
42. Certified Heating and Services
43. Duncan's Limited
44. Fred's Plumbing and Heating
45. FSC Architects and Engineers
46. Hurlburt Enterprises
47. Kobayashi and Zedda Architechs Limited
48. Northerm windows and Doors
49. Olsen's Resource consulting
50. Sourdough Plumbing and Hot Water Heating
51. Sow's Ear Builders and Energy
52. Wayne Wilkinson
53. Dynamic systems
54. Yukon Contractors' Association
55. Martin Crill
56. Saskia Bunicich
57. Bob Edzerza

Lunch (working lunch with Marbek and Construction reps) 12:00 – 1:30 pm

1. Paul Robillard
2. Chris Pulfer
3. Jack Habart
4. David Shipley
5. Arcrite Northern
6. Archtech Ventillation
7. Certified Heating and Services
8. Duncan's Limited
9. Fred's Plumbing and Heating
10. FSC Architects and Engineers
11. Hurlburt Enterprises
12. Kobayashi and Zedda Architechs Limited
13. Northerm windows and Doors
14. Olsen's Resource consulting
15. Sourdough Plumbing and Hot Water Heating
16. Sow's Ear Builders and Energy
17. Wayne Wilkinson
18. Dynamic systems
19. Yukon Contractors' Association
20. Juergen Korn

Afternoon Bilateral Meetings 1:30 – 4:30 pm

DSM program managers Meeting

- Focus is on better understanding of expected future program directions, lessons learned to date, etc. This is to ensure that we design the study structure (eg. sub sectors, end uses etc. in a way that will be most useful to the Yukon. Also to ensure that best available program and market data is identified and accessed.

1. Marbek Rep
2. Wayne Tonsi
3. Krista Roske
4. Shane Andre/Cathy Cottrell
5. Janet Patterson
6. Laura Carlson
7. Marianne Gregoire
8. Juergen Korn
9. David Black

Sales Data Meeting

- Focus is on details of sorting and exchanging customer sales into the sub sectors etc. discussed in the morning session. Discussions will involve strategies for dealing with imperfect date. Also to ensure that best available program and market data is identified and accessed.

1. Marbek Rep
2. Wendy Scramsted
3. Tom Debolt
4. Wesley Marsh
5. Greg Finnegan
6. Mona Politt-Smith

Load Forecast Meeting

- Need to understand current YEC/YECL assumptions re: future load growth, what level of detail data is available at, etc. This will enable us to align the study's reference case with electrical load forecasts.

1. Marbek Rep
2. Cameron Osler
3. Helen Booth
4. Randy Morgan

System Planning Meeting

- Need to understand system constraints, technology options under consideration to ensure that study structure and assumptions align with Yukon needs.

1. Marbek Rep
2. Hector Campbell
3. Marc-Andre Lavigne
4. Phil Borgel
5. Manon Moreau

Appendix B Market Characterization Methodology

Market Research Methodology

Client: Yukon Energy Corporation (YEC)
Yukon Electrical Company Limited (YECL)
Re: Market Research Methodology
Project: Residential and Commercial DSM Program Design
Version: September 24, 2012 – As delivered

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1. Sub-sector Research Focus

The following table presents the three sub-sectors that were researched. Further information can be found in the *Team Discussion Paper on Program Focus*.

It should be noted that the sub-sectors presented herein differ slightly from those presented in the discussion paper. This minor change was incorporated to optimize the use of resources and avoid "pre-establishing" the program design.

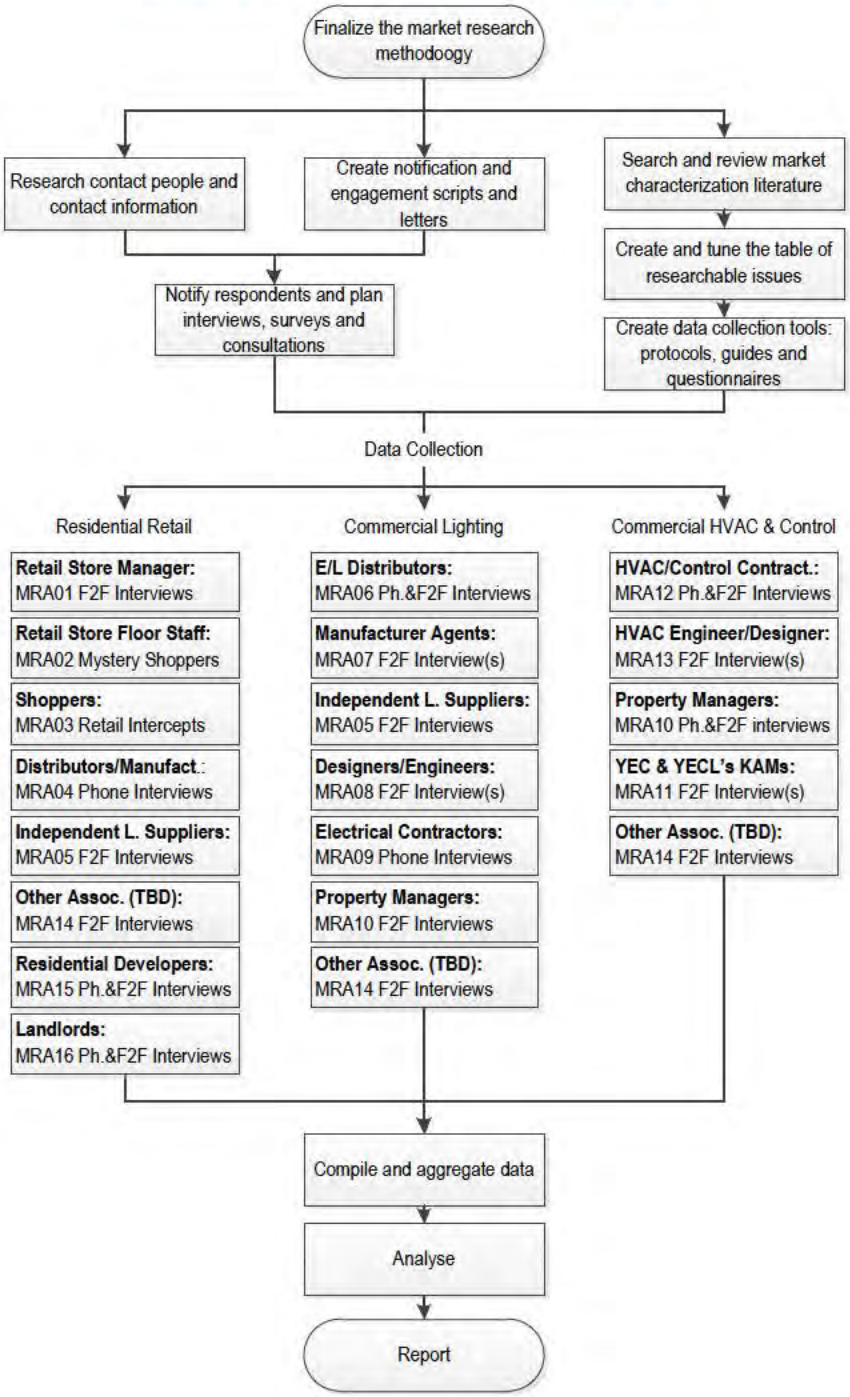
Exhibit 1 Sub-sector Research Focus

Sub-sector	Description
Residential Sector	
RR - Residential Retail	We initially envisioned a program that would directly engage retailers. The program would target typical equipment sold by retailers, both in-store and online. Equipment that could be targeted included lamps and fixtures (*maybe* including self-ballasted screw-in CFL), domestic appliances such as clothes washers and refrigerators, programmable thermostat, and low-flow showerheads.
Commercial Sector	
CL - Commercial Lighting	We initially envisioned a program that would directly engage with electrical and lighting distributors. Rebate programs have proven to be quite effective in the commercial lighting sector. The program would increase the penetration of energy efficient equipment.
CHCR - Commercial HVAC & Control Retrofit	We initially envisioned a program in which contractors would proactively develop business with commercial building owners and managers to: 1) identify opportunities in HVAC and controls; 2) convince building and management owners to invest; and, 3) implement either low-cost/no-cost measures, or capital-intensive conservation measures, or both. Retro commissioning and energy auditing are two pathways to achieve items 1 and 2 stated above. We wanted to research the market readiness and interest in such an approach and, in the absence of readiness, the tolerance of the market for direct intervention by YEC & YECL.

2. General Market Research Approach

Exhibit 2 outlines the major steps in the design and implementation of the market research activities as well as the identified participants.

Exhibit 2 General Market Research Approach



3. Sampling

Exhibit 3 outlines the proposed sample sizes, the actual sample sizes, and a justification for the gap between proposed and actual. Population estimates were made to establish the targets.

Exhibit 3 Sampling Plan

Market Data Source (Market Actors)	Market Research Activity	Population Estimates	Sample Targets	Sample Actual	Justification
RR – Retail Store Managers	F2F Interviews (MRA01)	10	4	4	Nothing to report.
RR – Retail Store Floor Staff	Mystery Shoppers (MRA02)	1,000	20	6	Only six relevant stores in Whitehorse; 3 lighting; 3 appliances.
RR – Shoppers	Retail Intercepts (MRA03)	20,000	30	22	More challenging and time-consuming than expected.
RR – Suppliers (All types. To be narrowed down.)	Phone Interview (MRA04)	50	2	0	Was cancelled. Most of retailers interact with a website rather than with individuals
RR & CL – Independent Lighting Retailers	TBD – Likely F2F Interviews (MRA05)	15	3	1	Only one was found at the time.
RR – Residential developers / contractors	F2F or phone interviews (MRA15)	6	0	3	These interviews were added mid-course during the study.
RR – Landlords	F2F or phone interviews (MRA16)	10	0	4	These interviews were added mid-course during the study.
CL – Electrical and/or Lighting Distributors (E/L Distributors)	F2F Interviews (MRA061)	3	1	2	The two distributors with branches in the YT responded. 6 other national distributors w/o a YT branch were contacted but declined to respond.
	Phone Interviews (MRA062)		2	0	
CL – Manufacturer Agents	Phone Interviews (MRA07)	2	1	1	Nothing to report.
CL – Lighting designers and/or Engineer	F2F Interview (MRA08)	3	1	1	Nothing to report.
CL – Electrical Contractors	Phone Interviews (MRA09)	26	6	5	Response rate was low. All 26 contractors were contacted.
CL & CHCR – Large Property Managers	F2F Interviews (MRA101)	8	2	4	It was not possible to find a fifth manager that was willing to respond.
	Phone Interviews (MRA102)		3	0	
CL & CHCR – YEC & YECL Key Account Managers	F2F Meeting (MRA11)	TBD	2	0	Was cancelled because there is no account manager.
CHCR – HVAC or Control Contractors	F2F Interviews (MRA121)	5	1	3	Response rate was slightly lower than expected.
	Phone Interviews (MRA122)		3	0	
CHCR – HVAC or Control Engineer/Designer	F2F Interviews (MRA13)	5	2	2	Nothing to report.
RR, CL & CHCR – Multiple Key Stakeholders	F2F Interviews (MRA14)	N/A	7	6	We were not able to talk to the Contractors Association.

Where F2F means face-to-face, RR means Residential Retail, CL means Commercial Lighting, HVAC means Heating, Ventilation and Air-Conditioning, CHCR means Commercial HVAC and Control Retrofit, E/L means Electrical and/or Lighting, TBD means To Be Determined and MRA means Market Research Activity.

4. Details on the Market Research Activities

This section describes the research activities that were designed and undertaken. The discussion presents a description of each research activity, the justification for using the selected strategy, and the approach to recruiting respondents.

MRA01 RR – Retail Store Manager Interviews

Short description	Face to face, directed, in-depth interviews with Retail Store Managers (approx. 1h)
Justification of the choice of activity	Population size is small. Their views are very important because we envision working with them as trade allies. Managers will be able to provide meaningful market insights on their sales and the behavior of their customers. Therefore, it was important to use an in-depth and explorative method such as face-to-face interviews.
Identification of participants, notification and recruitment	YEC and/or YECL did not have contact information. Therefore, it was necessary to send a notification letter and then conduct cold calls to identify potential respondents. Eligible respondents needed to be in charge of the purchase and stocking of selected store(s). A representative from YEC called the stores directly, inquired about the managers, established the individual's eligibility, and attempted to schedule a telphone meeting.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All the respondents were sent the interview guides before the interview. ICF Marbek staff led the interviews, with a YEC staff member participating in most interviews.

MRA02 RR – Mystery Shoppers

Short description	30-minute visit to stores such as Canadian Tire, Walmart, Home Hardware, etc. The protocol was: 1) Go to store and make observations on the shelving displays of the selected equipment, most likely lighting equipment and appliances; 2) Make notes on merchandizing activities and promotions; 3) Talk to a member of the floor staff responsible for a specific display (same as for 1), ask a short set of questions, and note the answers.
Justification of the choice of activity	Get unbiased market intelligence through observations rather than relying on the views of the store managers. Reduce the number of questions to the store managers and thus the duration of the interviews by getting the information at the source. Relatively easy to set up.
Identification of participants, notification and recruitment	YEC and YECL staff identified the stores.
Approach to data collection	ICF Marbek created a mystery shopper protocol that contained the scenarios, the questions and, a template to write notes and observations. There were no recording, transcripts, and photos. ICF Marbek briefed the mystery shoppers and aggregated the notes.

MRA03 RR – Retail Intercepts

Short description	15-minute in-store in-person interview with targeted shoppers.
Justification of the choice of activity	We wanted to understand the decision-making process of someone who is buying an incandescent light bulb/or non-ESTAR appliance, on the spot and at the moment when the experience was fresh in their mind. We envisioned that the potential program activities and tactics would include rebate and Point-of-Purchase materials. Therefore information from retail intercepts would be very valuable. A number of the candidate items for inclusion in the retail program are purchased infrequently. That means that general polling would randomly select a lot of people who haven't thought about these decisions for several years. Retail intercepts would not have to deal with all those "not applicables" because it would catch people right after they made the choice we are interested in.
Identification of participants, notification and recruitment	The interviews were coordinated with the store manager. The interviewers wore a YEC badge. There was one interviewer on site. The retail intercepts happened on the weekend. A short "notification letter" was prepared to share with the store staff. In the first approach employed, the interviewer identified him/herself to the staff at the cash registry. The staff was advised to buzz the interviewer if certain items were purchased, such as: 1) incandescent, CFL or LED light bulb(s); or, 2) a large appliance (E-STAR or not) such as a refrigerator, freezer, cloth washer, hot water tank, or dishwasher. The interviewer could then solicit the customer. A table and a few chairs provided a venue to conduct the interview. To boost the response rate, the interviewer had small gifts, which were the same coupons that were used by YECL in the Arctic Winter Game. The respondent used the "Price-is-Right" machine in place of a dice to earn a gift. It was found that this approach was ineffective as people rushed out without talking to the interviewer. A second approach was then used that was more effective. In this case, the interviewer intercepted the shoppers directly in the aisle e.g., in the lighting equipment section of the store. People were more willing to respond at that moment.
Approach to data collection	ICF Marbek created a retail intercept guide containing information such as, how to do the following: coordinate with the store manager; brief the staff at the cash registry; set up (chairs and table) and wear visual identification tags (YEC and/or YECL logos); approach customers and distribute gifts, including introduction script, questions and reporting. The results were documented using a questionnaire with ticked boxes.

MRA05 RR & CL – Independent Lighting Retailers Interviews

Short description	45-minute in-depth partially-directed interview(s). Independent lighting retailers are typically very small businesses (often one person), who import lighting equipment (lamps, fixtures) directly from the manufacturers and sell them directly to residential and commercial clients. They have very little infrastructure and overhead; many operate from their basement. Based on our observations, this group appears to sell premium quality equipment.
Justification of the choice of activity	It was assumed that the population of independent retailers was approximately 5 to 10. For such a small population, we believed that in-depth interviews would be the most effective means to obtain the needed market information. We knew little about these retailers. We suspected they might have a market share that is more significant in the Yukon than in other jurisdictions. We believed that we needed to maintain flexibility for improvisation during the interview. Hence, a *partially-directed* interview style was employed because: 1) The individuals and their market roles were not clearly known; 2) It was difficult to predict what the most useful discussion topics were going to be.
Identification of participants, notification and recruitment	The retailers were identified through word-of-mouth and from the contact network of YEC and YECL staff.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues.

MRA06 CL – E/L Distributor Interviews

Short description	Electrical equipment distributors and specialized lighting distributors were consulted through 60-minute telephone and in-person, directed interviews. YEC or ICF Marbek staff conducted the interviews.
Justification of the choice of activity	It was known beforehand that the population of distributors in the Yukon would be small (approximately 3-5 firms), and therefore that the sample size would also be small. Also, some distributors operating in the Yukon are located outside the territory; consequently, it was anticipated that many interviews would be conducted by telephone. Since distributors are key actors in the supply chain, it was important to use an in-depth and explorative method. A "directed-interview" format was employed.
Identification of participants, notification and recruitment	YEC or YECL had information on the two distributors that have a local branch. ICF Marbek looked for other distributors through existing relationships and prior work in this sector. ICF Marbek sent an email to the non-resident distributors to ask them for an appropriate Yukon contact. There was one response; the identified contact was located in the Northwest Territories.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guides before the interview.

MRA07 CL – Manufacturer Agent Interview(s)

Short description	60-minute in-depth directed interview(s), primarily via telephone by YEC and ICF Marbek staff.
Justification of the choice of activity	Lamp manufacturer agents (or reps) have a valuable perspective on the lighting sector in the Yukon. Therefore, it was important to use an in-depth and explorative method. Because they are located outside of the territory, telephone interviews were employed. The nature and role of these organizations is relatively well known, and thus we used a "directed-interview" format.
Identification of participants, notification and recruitment	Manufacturer agents or representatives were identified through interviews with distributors and lighting designers. They are based in B.C. and Alberta, not in the Yukon. ICF Marbek cold-called the individuals and scheduled the interviews from Ottawa.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guides before the interview.

MRA08 CL – Lighting Designers and/or Engineer Interview(s)

Short description	Lighting designers were consulted through in-person directed interviews.
Justification of the choice of activity	It was known beforehand that the population of lighting designers in Yukon would be small (approximately 1 to 5 individuals), and therefore that the sample size would also be small. Since designers are key actors in the supply chain, it was important to use an in-depth and explorative method such as face-to-face interviews.
Identification of participants, notification and recruitment	YEC staff knew one lighting designer and called them directly to book the appointment.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. The respondent was sent the interview guide before the interview.

MRA09 CL – Electrical Contractors Interviews

Short description	Electrical contractors were consulted through a 30-minute directed telephone interview.
Justification of the choice of activity	Contractors are important market influencers but are difficult to engage as they are very busy and often out of their office; hence, a telephone interview was preferred. The number of contractors was estimated to be approximately 20 to 50. Therefore we needed a larger sample size but also recognized that many may not be available to participate in the interview.
Identification of participants, notification and recruitment	YEC staff located electrical contractors through web searches and the Yellow Pages. Significant effort was required to convince the electrical contractors to participate. A formal notification letter was sent by YEC and YECL, followed by a cold-call from YEC staff.
Approach to data collection	ICF Marbek created a questionnaire based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA10 CL & CHCR – Large Property Managers Interviews

Short description	Large Property Managers were consulted via a 30 to 60 minute in-depth telephone or in-person interview.
Justification of the choice of activity	Since large Property Managers are important market influencers, we used an in-depth and explorative method.
Identification of participants, notification and recruitment	We identified relevant property managers through existing YEC & YECL relationships. Commercial key accounts were particularly targeted. YEC & YECL key account managers were able to provide the contact information. Interviews were arranged by YEC personnel.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA12 CHCR – HVAC or Control Contractors Interviews

Short description	We consulted with the HVAC and Control Contractors through a combination of telephone and in-person interviews.
Justification of the choice of activity	HVAC and Control Contractors are important influencers in the supply chain for HVAC and control retrofits, as it was assumed that very few of these retrofits actually involve an extensive design team. Consequently, it was important to employ an in-depth and explorative method such as interviews.
Identification of participants, notification and recruitment	We identified HVAC and control contractors through existing ICF Marbek relationships, including CPR workshop participants. Additional contractors were identified through sources such as the electrical contractors association, the mechanical contractors association, NRCan service provider lists, the Yellow Pages, Google searches, etc. YEC sent a notification email to the targeted individuals. Then YEC staff followed-up by telephone to set up a meeting.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA13 CHCR – HVAC or Control Engineer/Designer Interview(s)

Short description	HVAC and Control Engineers/Designers were consulted through in-person directed interview(s).
Justification of the choice of activity	It was known beforehand that the population of HVAC and Control Engineers/Designers in the Yukon would be small (approximately 1 to 5 individuals) and therefore the attainable sample size would also be small. HVAC designers are important potential program partners because they could undertake direct customer engagement, act as RCx agent or energy auditor and/or develop projects to be financed by a potential Utilities program.
Identification of participants, notification and recruitment	YEC staff called local engineering firms to identify the designers among their staff. A representative of YEC called the individuals to schedule the interviews.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the interview guide before the interview.

MRA14 RR, CL & CHCR – Interviews with Multiple Key Stakeholders

Short description	60 minute undirected in-person interviews with Stakeholders.
Justification of the choice of activity	Many of the stakeholders represent potential program implementation partners. We wanted to know the role/mission/core business of each of the organizations, as well as their areas of particular strength/interest. Each interview was tailored to the specific organization based on available information. Therefore an "*undirected* interview" approach was employed.
Identification of participants, notification and recruitment	YEC provided the necessary contact information and arranged the meetings. The relevant stakeholders included: • Whitehorse Chamber of Commerce, • Association of Professional Engineers of Yukon Territory (APEY), • Yukon College, • Yukon Technology Innovation Centre, • Consulting Engineers of Yukon, Chamber of Mine, • and/or Yukon Contractors Association Meetings were in-person as much as possible. A representative of YEC made the telephone call to plan the meeting. Many meetings were planned during the week of April 16, 2012, when a representative of ICF Marbek was in Whitehorse.
Approach to data collection	A short description of the interview's purpose was sent by email to each participant. A short and flexible meeting agenda was created at the beginning of each meeting.

MRA15 RR – Interviews with New Condominium and Townhouse Developers

Short description	60 minute undirected in-person interviews with developers.
Justification of the choice of activity	Much of the current new home construction in the Whitehorse area is townhouse and condominium developments. These units are generally sold with lighting and appliances already installed. As these developers are making choices on a large volume of lighting and appliances, they represent a large part of the residential retail market. Given the tight real estate market, customers have less influence on these decisions than they could have in a more competitive market. The number of developers is fairly small. They can provide meaningful market insights on their current practices and the behavior of their customers. Therefore it was important to use an in-depth and explorative method such as in-person interviews.
Identification of participants, notification and recruitment	YECL provided names of the developers that are setting up accounts. Meetings were in-person as much as possible. A representative of YEC set up the meetings.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

MRA16 RR – Interviews with Residential Rental Property Managers and Landlords

Short description	60 minute undirected in-person interviews with property managers and landlords.
Justification of the choice of activity	Rental units make up a large percentage of the residences in Whitehorse. The decisions regarding types of lighting and appliances are generally made by the property managers or landlords. As these managers and landlords make choices on a large volume of lighting and appliances, they represent a large part of the residential retail market. Given the tight real estate market, renters have less influence on these decisions than they could have in a more competitive market. The number of managers and landlords is fairly small. They can provide meaningful market insights on market barriers and the behavior of their customers. Therefore it was important to use an in-depth and explorative method such as in-person interviews.
Identification of participants, notification and recruitment	YECL provided names of the landlords. Meetings were in-person as much as possible. A representative of YEC set up the meetings.
Approach to data collection	ICF Marbek created an interview guide based on the high-level research questions and the list of researchable issues. All respondents were sent the questionnaire before the interview.

5. Table of Researchable Issues

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
Residential Retail Program																	
Research question #1: RR - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
RR101	Demographics	Actors			X												
RR102	Purchase: EE equipment or non-EE equipment	Actors			X												
RR103	Firmographics	Actors	X			X	X									X	X
RR105	Challenges currently faced by the organisation	Actors	X			X	X									X	X
RR107	Management framework/Org Chart	Actors	X													X	X
RR140	Missing Market Actors	Actors	X			X	X									X	
Research question #2: RR - How do actors interact with each other in the absence of a program?																	
RR104	Major customer segments	Structure	X			X	X									X	X
RR106	Major suppliers	Structure	X				X									X	X
RR108	Best media outlets to reach your businesses	Structure	X	X	X	X	X									X	X
RR109	Best media outlets used to reach out to clients	Structure	X			X	X									X	X
RR110	Best source(s) of information on best practices	Structure	X	X	X		X									X	X
RR111	Clients' purchase drivers	Structure	X	X	X	X	X									X	X
RR115	Reasons for making special efforts wrt EE	Structure	X	X		X	X									X	X
RR117	Drivers of salesforce	Structure	X		X												
RR130	Main means to train salesforce	Structure	X													X	
RR118	Organisation's purchase/stocking drivers	Structure	X													X	X
RR128	Program activity most likely to partake in	Structure	X		X		X									X	X
RR150	Linear shelf space of EE products vs baseline	Structure		X													
RR151	Promo on retail price of EE products vs baseline	Structure		X													
RR152	Merchandising activities of EE products vs baseline	Structure		X													
RR163	How is a supplier selected?	Structure	X														
Research question #3: RR - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
RR112	Clients' purchase barriers	Barriers	X	X	X		X									X	X
RR113	Visibility (shelf space) of EE equipment as compared with others	Barriers	X		X												
RR114	Ease of getting information on EE of product in the store	Barriers		X	X												
RR116	Reasons for NOT making more efforts wrt EE	Barriers	X	X		X	X									X	X
RR119	Perception of applicability of the information available	Barriers	X	X	X	X	X									X	
RR120	Issues with availability of equipment and services	Barriers	X			X	X										X

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
RR121	Technical issues with EE equipment and services	Barriers	X			X	X										
RR122	How good at promoting EE are - Retailers in general?	Barriers				X	X										X
RR123	How good at promoting EE are - Retail store managers?	Barriers		X													
RR124	How good at promoting EE are - Suppliers?	Barriers	X														X
RR125	How good at promoting EE are - Property Managers & landlords?	Barriers	X			X	X									X	
RR155	How good at promoting EE are - Contractors?	Barriers	X			X	X										X
RR126	Credibility of YEC wrt EE and DSM	Barriers	X	X	X	X	X									X	X
RR127	Credibility of the YECL wrt EE and DSM	Barriers	X	X	X	X	X									X	X
RR153	Credibility of YG organizations such as ESC and Yukon Housing	*Barriers*														X	X
RR154	Out-of-stock status on EE product vs Baseline (yes/no)	Barriers		X													
RR160	Extent of the double-agent barrier	Barriers			X											X	X
RR161	Overall satisfaction re: existing Yukon program - Good	Barriers			X												X
RR162	Overall satisfaction re: existing Yukon program - EcoEnergy	Barriers			X												X
Commercial Lighting Program																	
Research question #1: CL - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
CL201	Firmographics	Actors						X	X	X	X	X					
CL203	Challenges currently faced by the organisation	Actors						X	X	X	X	X					
CL205	Management framework/Org Chart	Actors						X		X		X					
CL206	Find the lighting designers	Actors						X	X								
CL240	Missing market actors	Actors						X	X	X							
Research question #2: CL - How do actors interact with each other in the absence of a program?																	
CL202	Major customer segments	Structure						X	X	X	X	X					
CL204	Major suppliers	Structure						X			X						
CL207	Best media outlets to reach your businesses	Structure						X	X	X	X	X					
CL208	Best media outlets used to reach out to clients	Structure					X	X	X	X	X						
CL209	Best source(s) of information on best practices	Structure						X	X	X	X						
CL210	Clients' purchase drivers	Structure					X	X	X	X	X	X					
CL212	Reasons for making special efforts wrt EE	Structure						X	X	X	X	X					
CL214	Drivers of salesforce	Structure						X									
CL240	Major means to train salesforce	Structure						X									
CL215	Organisation's purchase/stocking drivers	Structure						X				X					
CL227	Program activity most likely to partake in	Structure						X	X	X		X					
CL241	Occurrence of the electrical contractor to decide (or exert heavy influence) on what equipment to install	Structure								X	X	X					

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
Research question #3: CL - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
CL211	Clients' purchase barriers	Barriers					X	X	X	X	X						
CL213	Reasons for NOT making more efforts wrt EE	Barriers						X	X	X	X	X					
CL216	Perception of Applicability of the information available	Barriers					X	X		X							
CL217	Issues with availability of equipment and services	Barriers					X	X	X	X	X	X					
CL218	Technical issues with EE equipment and services	Barriers					X	X	X	X	X						
CL219	How good at promoting EE are - Lighting Distributors?	Barriers					X		X	X	X	X					
CL220	How good at promoting EE are - Independent Lighting Suppli	Barriers						X	X	X	X	X					
CL221	How good at promoting EE are - Lighting Designers?	Barriers					X	X	X		X	X					
CL222	How good at promoting EE are - Lighting manufacturers age	Barriers					X	X		X							
CL223	How good at promoting EE are - Electrical Contractors?	Barriers					X	X	X	X		X					
CL224	Current market penetration of certain EE-specific services	Barriers						X	X	X	X	X					
CL225	Credibility of YEC wrt EE and DSM	Barriers						X	X	X	X	X					
CL226	Credibility of the YECL wrt EE and DSM	Barriers						X	X	X	X	X					
CL242	Occurrence of the electrical contractors to substitute equipment after the design phase of the project	Barriers								X	X	X					
CL250	Credibility of YG organizations such as ESC and Yukon	*Barriers*															
Commercial HVAC & Control Retrofit Program																	
Research question #1: CH - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
CH301	Firmographics	Actors											X	X			
CH303	Challenges currently faced by the organisation	Actors											X	X			
CH304	Management framework/Org Chart	Actors											X				
CH306	Find the HVAC/Control designers	Actors										X	X				
CH307	Find the EE experts	Actors										X	X	X			
Research question #2: CH - How do actors interact with each other in the absence of a program?																	
CH302	Major customer segments	Structure											X	X			
CH308	Major suppliers	Structure										X	X				
CH309	Best media outlets to reach your businesses	Structure											X	X			
CH310	Best media outlets used to reach out to clients	Structure												X			
CH311	Best source(s) of information on best practices	Structure											X	X			
CH313	Reasons for making special efforts wrt EE	Structure											X	X			
CH322	Clients' purchase drivers	Structure											X	X			
CH327	Reasons for investing	Structure										X					
CH328	Program activity most likely to partake in	Structure										X	X	X			

Researchable Issues		Characte-rization Component	MRA01 Retail Managers	MRA02 Retail Staff	MRA03 Shoppers	MRA04 Retail Suppliers	MRA05 Indepen-dent Suppliers	MRA06 E/L Distri-butors	MRA07 Manufac-turers	MRA08 Lighting Desi-gners	MRA09 Electrical Contrac-tors	MRA10 Property Managers	MRA12 HVAC/ Control Contra-ctors	MRA13 HVAC/ Control Engi-neers	MRA14 Stake-holders	MRA15 Condo Develo-pers	MRA16 Resi-dential Land-lords
CH342	Occurrence of the contractor to decide (or exert heavy influence) on what equipment to install	Structure										X	X	X			
Research question #3: CH - Why doesn't energy efficiency have a higher uptake in the absence of a program?																	
CH312	Reasons for NOT making more efforts wrt EE	Barriers											X	X			
CH314	Clients' purchase barriers	Barriers											X	X			
CH315	Issues with availability of equipment and services	Barriers										X	X	X			
CH316	Technical issues with EE equipment and services	Barriers											X	X			
CH317	How good at promoting EE are - HVAC/Control Engineers?	Barriers										X	X				
CH318	How good at promoting EE are - HVAC/Control Contractors?	Barriers										X		X			
CH340	How good at promoting EE are - Equipment Suppliers?	Barriers											X	X			
CH320	Reasons for not entering the EE business or using EE to boost sales	Barriers											X	X			
CH323	Reasons for not investing (more)	Barriers															
CH324	Extent of the double-agent barrier	Barriers										X	X	X			
CH325	Credibility of YEC wrt EE and DSM	Barriers											X	X			
CH326	Credibility of the YECL wrt EE and DSM	Barriers											X	X			
CH350	Credibility of YG organizations such as ESC and Yukon	*Barriers*															
CH341	Perception of Applicability of the information available	Barriers												X			
Research question #4: CH - Why is the current market penetration of EE services and equipment and what is the naturally-occuring trend?																	
CH319	Current market penetration of certain EE-specific services	Baseline										X	X	X			
CH321	Recent investment in EE?	Baseline										X					
Other Organizations and Stakeholders																	
Research question #1: RR, CL & CH - Who are the actors, and what's their strenghts and weaknesses with regard to energy efficiency?																	
OO401	Mission and vision	Actors													X		
OO402	Existing conservation, sustainability, GHG reduction goals	Actors													X		
OO403	Challenges currently faced by the organisation	Actors													X		
OO404	General interest in EE	Actors													X		
OO405	Knowledge wrt EE	Actors													X		
OO406	Management framework/Org Chart	Actors													X		
OO407	Human resources	Actors													X		
OO408	Logistical resources (Office?, IT?)	Actors													X		
OO409	Size of membership or extend of visibility	Actors													X		
OO410	Media to the market that are being used	Actors													X		
OO411	Other resources (training materials?, methods?, data?)	Actors													X		

Saving energy your way

Survey results summary

Total No. of Surveys 449

Question #1 - USERS SHOULD LIMIT DEMAND BY USING ENERGY EFFICIENTLY

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
				75%	
39	10	9	56	335	449

Question #2 - DEVELOP EFFICIENCY PROGRAM - FUNDED BY CUSTOMERS

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
			39%		
35	26	58	177	153	449

Question #3 - DEVELOP EFFICIENCY PROGRAM - FUNDED BY UTILITIES & RESIDENTS

1	2	3	4	5	
STRONGLY DISAGREE	SOMEWHAT DISAGREE	NO STRONG OPINION	SOMEWHAT AGREE	STRONGLY AGREE	
				42%	
33	32	48	147	189	449

Question #4 - MOST EFFECTIVE WAYS TO REDUCE ENERGY USE IN THE YUKON

PUBLIC EDUCATION

Most Effective	Somewhat Effective	Not Effective	No Answer	
52%				
232	169	16	32	449

PROGRAMS THAT HELP PUBLIC TAKE ENERGY EFFICIENT ACTIONS

Most Effective	Somewhat Effective	Not Effective	No Answer	
55%				
246	149	15	39	449

SUBSIDIZE PRODUCTS THAT REDUCE CONSUMPTION

Most Effective	Somewhat Effective	Not Effective	No Answer	
61%				
276	121	13	39	449

TIME OF USE INCENTIVES

Most Effective	Somewhat Effective	Not Effective	No Answer	
	35%			
120	155	132	42	449

BETTER ENERGY EFFICIENCY STANDARDS FOR NEW CONSTRUCTION

Most Effective	Somewhat Effective	Not Effective	No Answer	
65%				
290	108	18	33	449

HIGHER EFFICIENCY STANDARDS FOR NEW APPLIANCES

Most Effective	Somewhat Effective	Not Effective	No Answer	
67%				
299	103	12	35	449

Question #5 - MOST EFFECTIVE WAYFOR YOU TO REDUCE YOUR ELECTRICITY CONSUMPTION

PUBLIC EDUCATION				
Most Effective	Somewhat Effective	Not Effective	No Answer	
49%				
219	140	48	42	449

PROGRAMS THAT HELP PUBLIC TAKE ENERGY EFFICIENT ACTIONS				
Most Effective	Somewhat Effective	Not Effective	No Answer	
50%				
224	147	33	45	449

SUBSIDIZE PRODUCTS THAT REDUCE CONSUMPTION				
Most Effective	Somewhat Effective	Not Effective	No Answer	
67%				
302	88	20	39	449

TIME OF USE INCENTIVES				
Most Effective	Somewhat Effective	Not Effective	No Answer	
	31%			
128	138	130	53	449

Yukon Energy Corporation

Knowledge, Awareness and Opinion Research
Public and Stakeholder Survey Results
Research Report 2

Prepared by
Andrew Hume and Associates Ltd.
In association with Aasman Brand Communications

July 21, 2010

aasman
branding on purpose

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YUKON ENERGY CORPORATION
PUBLIC OPINION ONLINE SURVEY RESULTS – JUNE 2010

Introduction

A combination of telephone and online surveys were conducted with the public and community and business leaders in communities throughout the Yukon between June 2 – July 15, 2010.

The survey methods covered a range of questions on the Yukon Energy Corporation and energy related issues.

This report focuses on the results of two online surveys: an open public survey; and a targeted survey directed to community and business leaders. A report on the result of two telephone surveys of these same groups was filed previously and should be reviewed as complimentary findings to this report. A narrative summary of findings of the two telephone surveys is included in this report. Data from the two telephone surveys can be found in the previously filed report.

Both phone surveys were conducted prior to the launch of the public awareness campaign. The online surveys were conducted simultaneous with the campaign.

Participation in the public survey was promoted through an awareness campaign as well as on the Yukon Energy Corporation's website and an incentive was offered (pubic survey only) to enhance participation.

Research Goals

- To provide the Yukon Energy Corporation with current Knowledge, Awareness and Behaviour (KAB) among Yukon residents and business and community leaders toward the corporation and current and future energy needs.
- To build a renewed sense of trust and confidence among Yukon residents in the corporation supporting its vision of a clean energy future.

Research Objectives

- To establish baseline KAB data
- To effectively position the Yukon Energy Corporation and its vision for a clean energy future
- To inform public communications initiatives and campaign information and messaging undertaken by the Yukon Energy Corporation

Research Targets

To achieve a confidence level of 95% an overall target for all methodologies was 380 respondents. Research targets were surpassed.

• Public phone survey:	184
• Public online survey:	356
• Business and community leaders phone survey:	25
• Business and community leaders online survey:	41
TOTAL:	**606**

SECTION I
Summary of Public Telephone Survey Findings

Introduction

A telephone survey of 184 randomly selected Yukon residents in six communities was conducted between June 2 – 8, 2010.

- The majority of Yukon residents are aware the Yukon Energy Corporation is both a producer and distributor of power. However a significant number are not aware of the dual responsibility of the corporation with regard to the production and distribution of power as indicated by those who said the corporation was only a producer or only a distributor or did not know.

- A strong majority of respondents said it is important for them to know who produces and who distributes power.

- Hydro generated power is a clearly preferred alternative to diesel-generated power across all communities.

- There is a strong preference for the development of alternative energy sources. (For the purposes of the survey, 'alternative' was described as wind and geo-thermal).

  - Carmacks showed the highest level of support for alternative sources at 70% and residents of Marsh Lake showed the lowest support at 56%. In Whitehorse 65% of respondents identified alternative as a preferred source of power.

- When asked to think about the energy production and future needs, only slightly more than half (52%) of residents agreed that Yukon will not have enough energy to meet future needs. This was relatively consistent across all communities with the exception of Carmacks where 80% of respondents agree with this projection.

- A clear majority of respondents do not support diesel-generated power as a future energy source. The strongest support is for the development of new alternative energy sources followed by hydro.

- Yukon residents see large scale industry as the big driver in terms of creating the greatest demand for future energy needs followed by population growth (residential consumption). There was however a wide variance in response by different communities to this question ranging from a low of 50% (Dawson City) who see large industry as the biggest future power consumer, to 80% of respondents from Carmacks. In Whitehorse 52% of respondents said they saw large industry as creating the biggest energy demand.

- With reliability of the power supply, the majority of respondents feel there has been little change or it has improved over the past 12 months . Responses varied marginally by community with most in the 75%+ range in saying reliability has been better or the same.

- The majority of Yukon residents (78%) feel the reliability of power over the next five years is likely to remain unchanged or get better.

- Using Nunavaut/NWT and Edmonton for comparison, survey respondents were asked to indicate if they felt they paid more, less or the same for power. While Yukon residents feel they pay less or are not sure in relation to other northern residents they clearly feel they pay more than residents of Edmonton. Forty-four per cent (44%) of respondents said they were not sure.

- On the question of confidence in the Yukon Energy Corporation related to planning and developing clean energy sources to meet future needs, 58% said they had confidence in the corporation. The level of confidence ranged from a low of 30% in Haines Junction to a high of 80% in Carmacks. In Whitehorse 62% said they have confidence in the corporation.

- On the question of Yukoners assuming more personal responsibility toward energy conservation, 89% are in agreement.

- An equally high number (87%) of respondents agreed with a planning approach that would see new alternative energy sources developed in conjunction with hydro development to meet future needs.

- A strong majority (88%) reinforced their support for alternative and hydro by saying the Yukon needs to move away from diesel-generated power. Support for moving away from diesel-generated power ranged from a low of 70% in Haines Junction to a high of 90% in Whitehorse and Dawson City.

- Almost half (49%) of respondents were 51 years or older with over a one-third (37%) in the 31 to 50 year age group. The majority of respondents were also longer-term residents with 59% indicating 20 or more years of residency. Gender of respondents was relatively evenly divided.

- Sixty percent (60%) of respondents were surveyed in Whitehorse with 25 residents in Marsh Lake and Dawson City participating in the survey. For the smaller communities of Haines Junction and Carmacks 10 phone surveys were done in each community. In Teslin four surveys were conducted.

    - Note: It is important to note that the sample size in communities outside Whitehorse is not significant enough from which any conclusions can be drawn with any degree of confidence at an individual community level. The data indicated on a community-basis for some questions in this report is provided as a point of interest only and cannot be considered statistically significant unto itself.

SECTION II
Summary of Community and Business Leaders Telephone Survey Findings

Introduction
A telephone survey of 25 business and community leaders representing a cross sample of businesses, Yukon-wide associations and local community leaders was conducted between June 4 – 11, 2010.

- Yukon business and community leaders indicate a high degree of confidence (88%) in the Yukon Energy Corporations' assessment that new energy sources will be needed within the next five years in order to meet future demands.

- Consistent with the public phone survey, business and community leaders believe large industry will be a primary driver in future energy demands and indicate a strong preference for alternative energy followed by hydro development. Support for diesel-generated power is very low.

- Approximately one-third (32%) of business and community leaders feel energy reliability worsened over the past 12 months as compared to about 18% of public survey respondents while two thirds (66%) said reliability was the same or better .

- In terms of expected reliability over the next five years, business and community leaders feel more confident with almost half (45%) expecting reliability to improve and only 16% expecting reliability to get worse and over one-quarter (28%) expecting no change.

- Over three-quarters (76%) of business and community leaders feel Yukon businesses need to do more toward energy conservation. While this is a strong indicator that businesses feel the need to assume greater responsibility for conservation, the public's sense of personal responsibility is much higher at 89%.

    - Comments related to this question indicate that conservations is a 'shared responsibility' across all sectors.

- There is a high degree of support (84%) among business and community leaders for the development of alternative energy sources in combination with hydro. Alternative energy also received strong support from the general public.

- Also consistent with the public's view, business and community leaders strongly believe that moving away from a reliance on diesel-generated power is the right goal for the Yukon Energy Corporation to be pursuing.

- Additional comments suggested that multiple alternative sources need to be further explored including things like bio-fuels and waste-energy in addition to hydro, wind and geo-thermal and natural gas should also considered. Some suggest the corporation lacks creativity with respect to new clean energy sources and opportunities.

- While a strong majority (84%) believe the Yukon Energy Corporation should be developing clean energy sources, just over half (56%) of business and community leaders have confidence in the corporation's ability to effectively plan and develop clean energy.

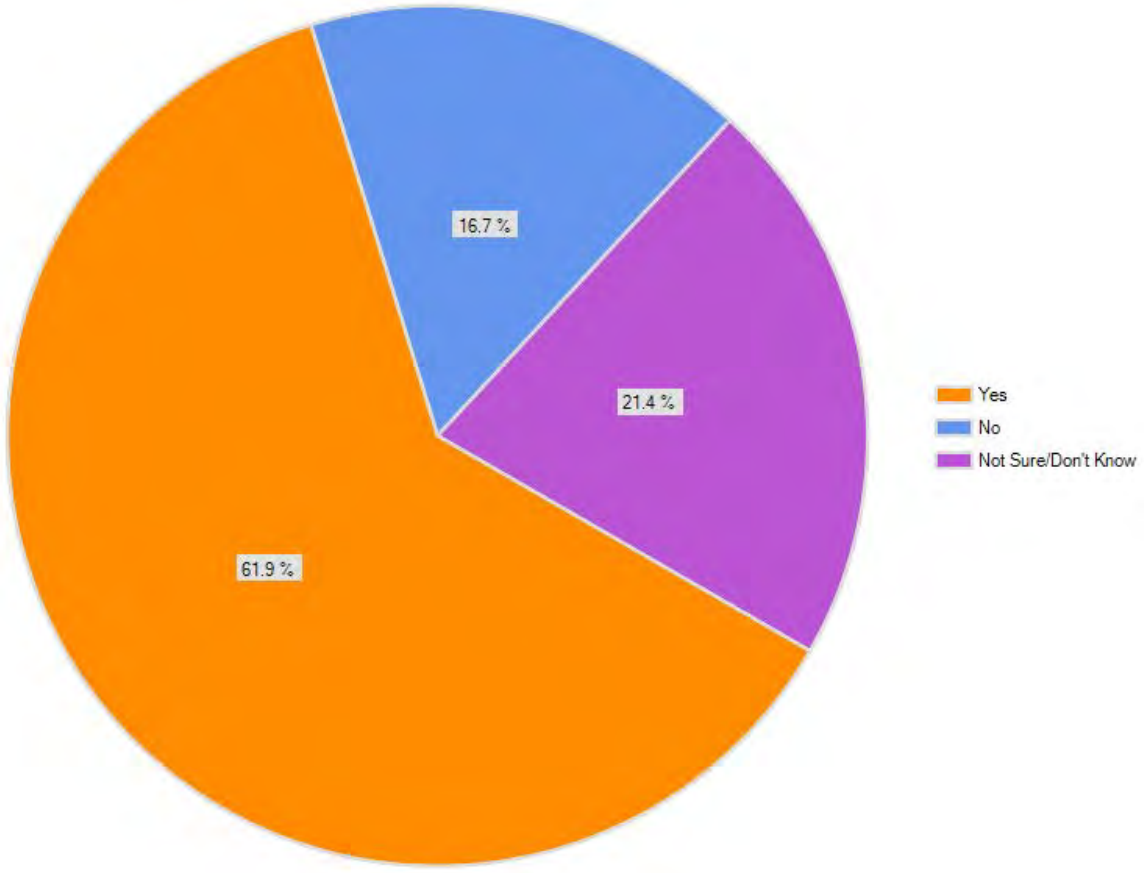
Additional comments included:

- Political influence and interference with the Yukon energy sector affects productivity and the ability to plan effectively. (Several mentions)
- Responding to external opposition and special interest groups interferes with effective planning.
- Years of opportunity to develop new clean energy sources have yielded little results.
- Reliability and cost need to be considered when developing alternative energy sources.
- Investment needs to be made in Yukon's power distribution system.
- Open up power generation to enable third parties to be become involved.
- The corporation needs to do more public consultation (this survey was a good start).
- Lack of a strategic plan and cost-benefit analysis.
- Lack of talk related to encouraging energy conservation.
- Important to plan and develop now to meet future needs and not get caught energy short. (Yukon Energy Corporation appears to be doing a good job projecting what future needs will be).
- More communication is needed on energy issues and options.

SECTION III
Findings from Community and Business Leaders Online Survey

Introduction
An online survey of 41 community and business leaders was conducted between July 7 – 15, 2010 representing individual businesses and organizations, Yukon-wide associations and local community leaders.

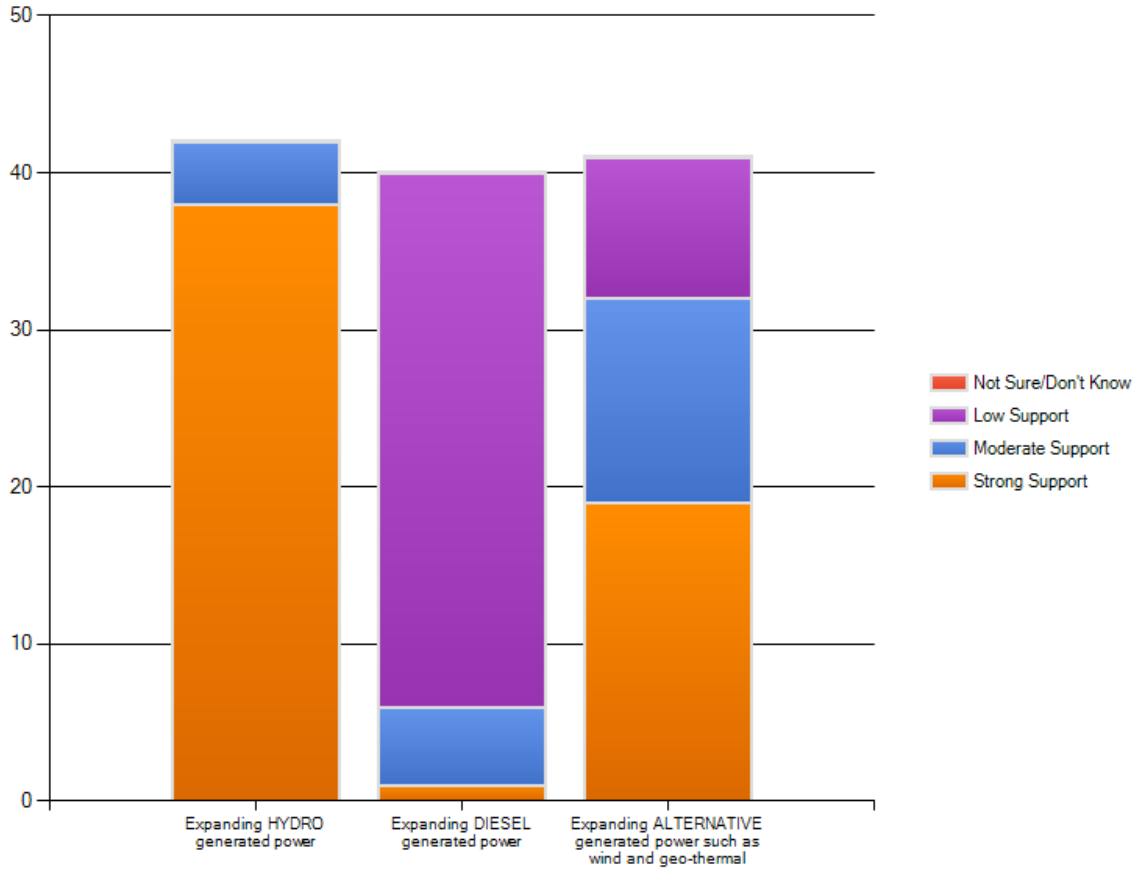
1. The Yukon Energy Corporation has identified the need for new sources of energy within the next five years to meet near future anticipated demands. Do you have confidence with this assessment?



Results show a 62% confidence level in the Yukon Energy Corporations' assessment of future energy needs with almost one-quarter (21%) of respondents unsure of their confidence. This reflects a statistically significant lower level of confidence than the telephone survey where 88% of respondents indicated a high degree of confidence in the corporation's future energy needs assessment.

The difference may be related to a greater level of comfort of anonymity with an online survey.

2. What level of support do you give each of the following power generation options?

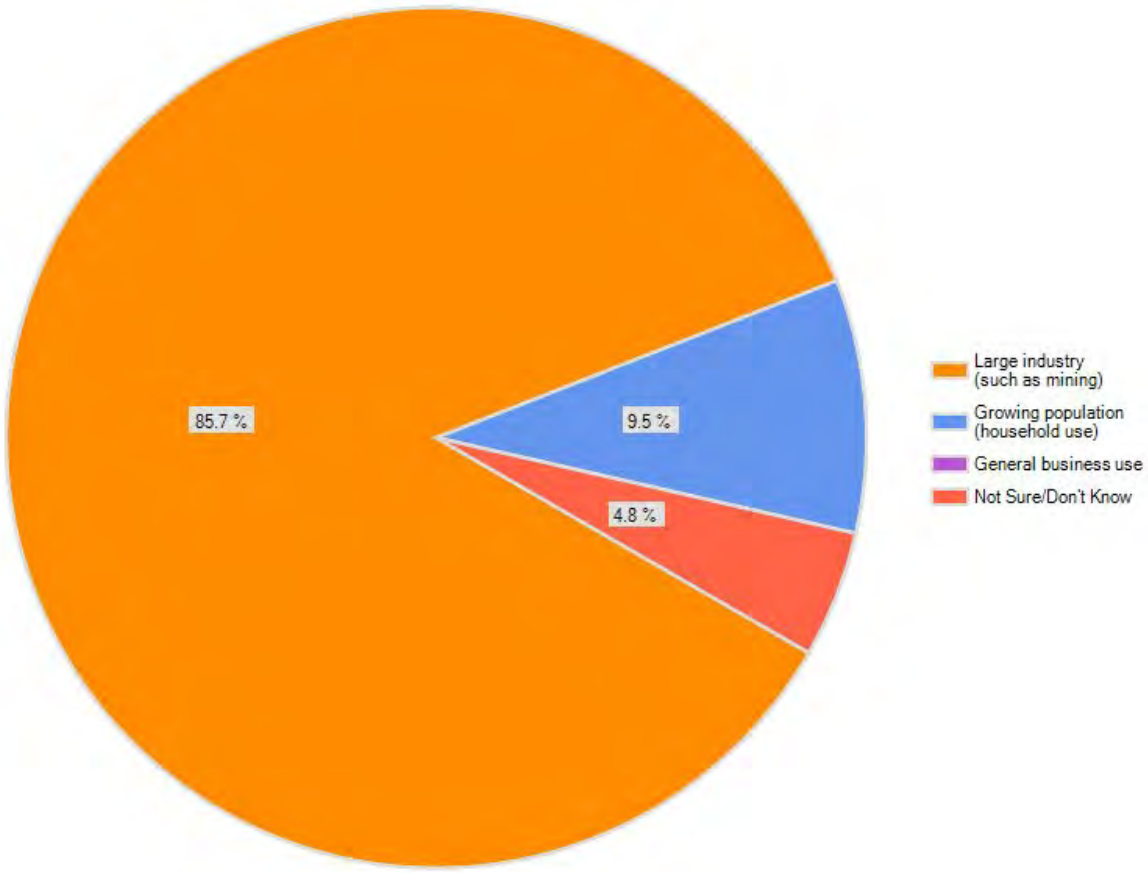


The online survey shows that business and community leaders have the strongest support (90%) for expanding hydro power followed by alternative generated power with 46% strong support. This differs from the community leaders phone survey which gave the expansion of alternative energy the strongest support followed by hydro sources.

The difference between the phone and online survey results may be related to an ideal preference reflected in the phone survey versus a more pragmatic view of what is realistically achievable as indicated by the online survey. Online surveys allow respondents more time to contemplate their view.

Phone surveys can include a degree of bias with respondents responding in what they perceive as the most politically or socially correct way, where online surveys allow for a greater sense of anonymity. Phone surveys also indicate 'top-of-mind' response whereas online surveys provide greater reflection time on a question. It is important therefore to consider both methodologies when assessing the data.

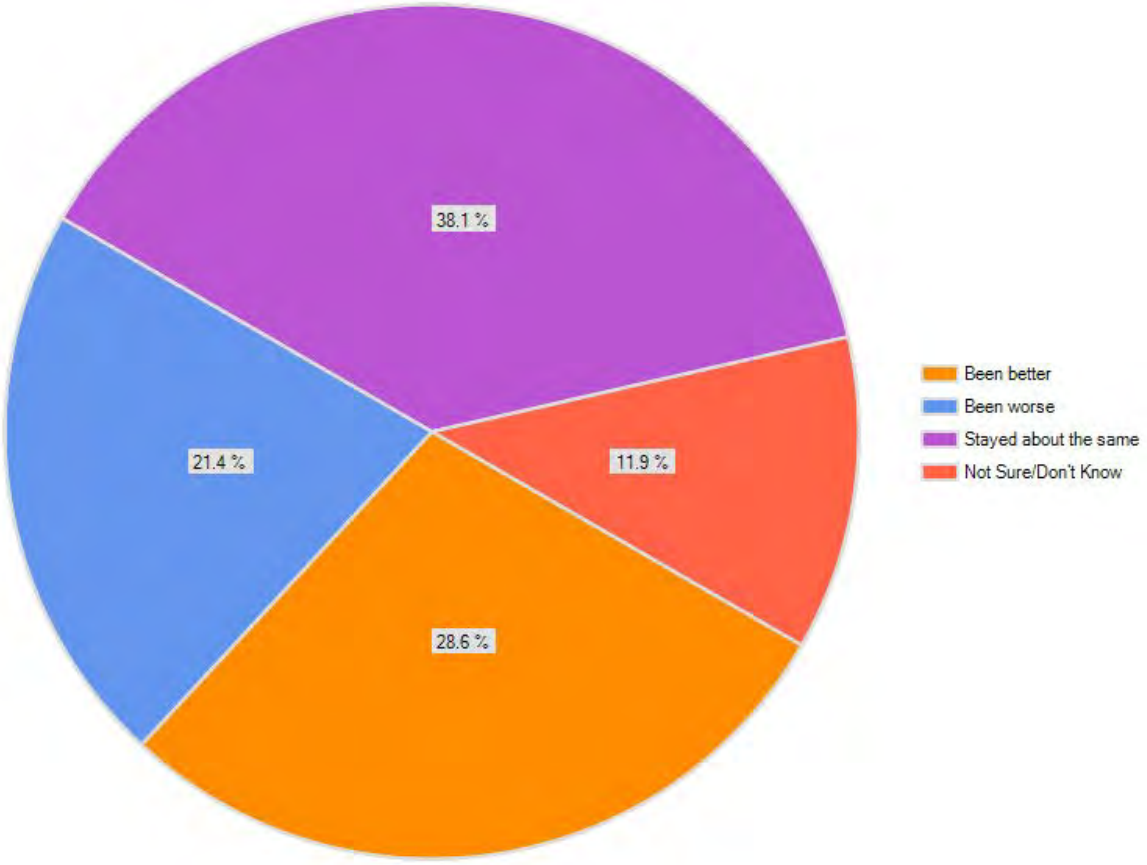
3. Which of the following will create the SINGLE GREATEST DEMAND on Yukon's future energy needs?



Both the online and phone surveys show community leaders believe large industry will create the greatest demand on future energy needs, however more respondents to the phone survey were unsure on this question than those who responded to the online survey.

- Phone Survey: 20% unsure
- Online Survey: 5% unsure

4. Over the past 12 months, has reliability in the supply of power:



On the question of past energy reliability, two-thirds (66%) of respondents to both the phone and online surveys said their power supply had remained the same or been better over the past 12 months.

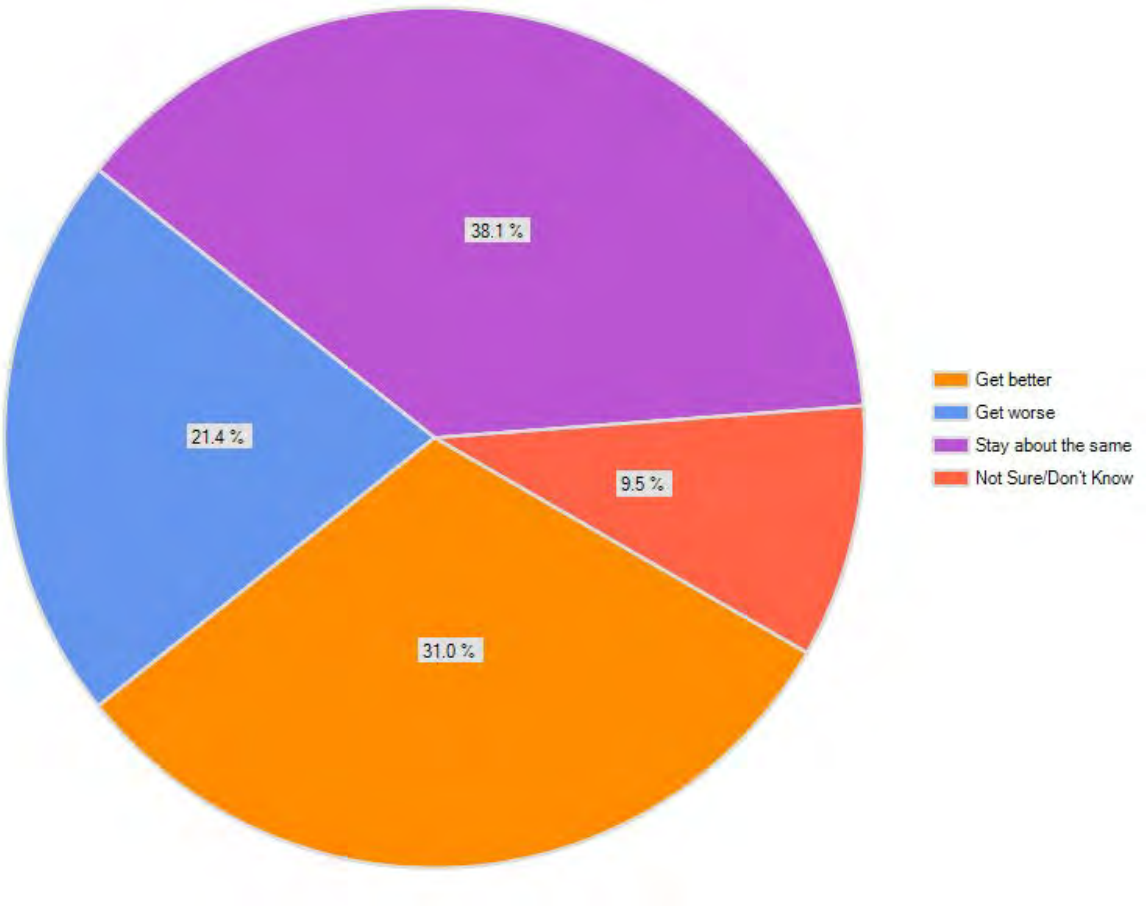
Note: The survey provided two 'confidence' indicators:

- One that relates to the corporation's ability to effectively plan and develop 'clean energy sources' to meet future needs; and
- One that relates to the provision of a stable or improved supply of energy in the future.

Q 5 (following page) relates to the later issue (stay the same or get better over the next 5 years) and shows a higher confidence level (68%) as opposed to Q 9 which focuses on confidence relative to the development of 'clean energy' sources to which 46% said they had confidence in the corporation's ability.

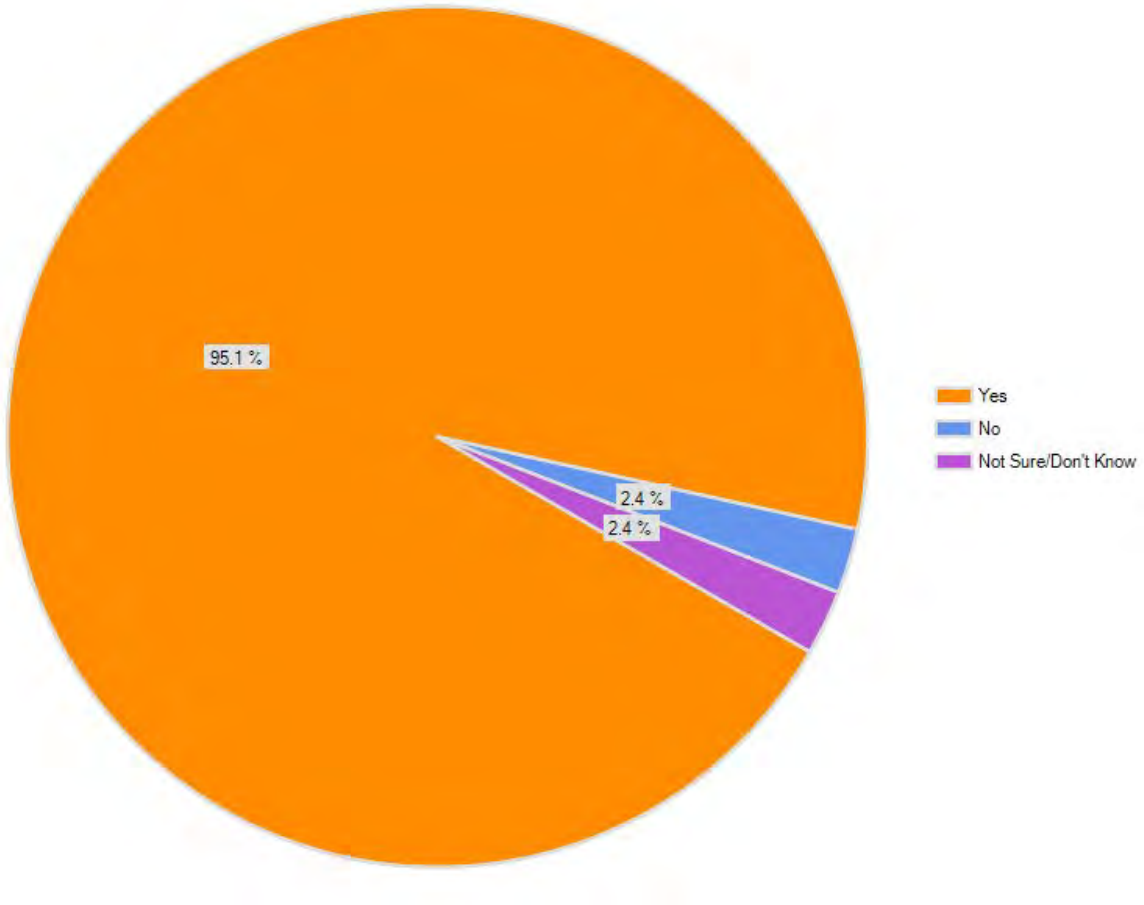
It should be further noted however that 20% of respondents to Q 9 also indicated they "did not know/not sure" about their level of confidence indicating an important margin for improvement in the overall confidence level in relation to planning a clean energy future.

5. In the next 5 years, do you expect the reliability of power to:



Thinking about anticipated energy reliability over the next five years an equal number of respondents to both survey methods (69%) expect the energy supply to remain the same or get better while a slightly higher percentage of online survey respondents versus phone respondents anticipated energy reliability would worsen (22% vs 16% respectively). An equal number from both survey methods (12%) indicated they are not sure about the future in terms of energy reliability.

6. Should business and industrial energy users be developing plans to use better energy conservation technologies, equipment and operational practices to help reduce demand?

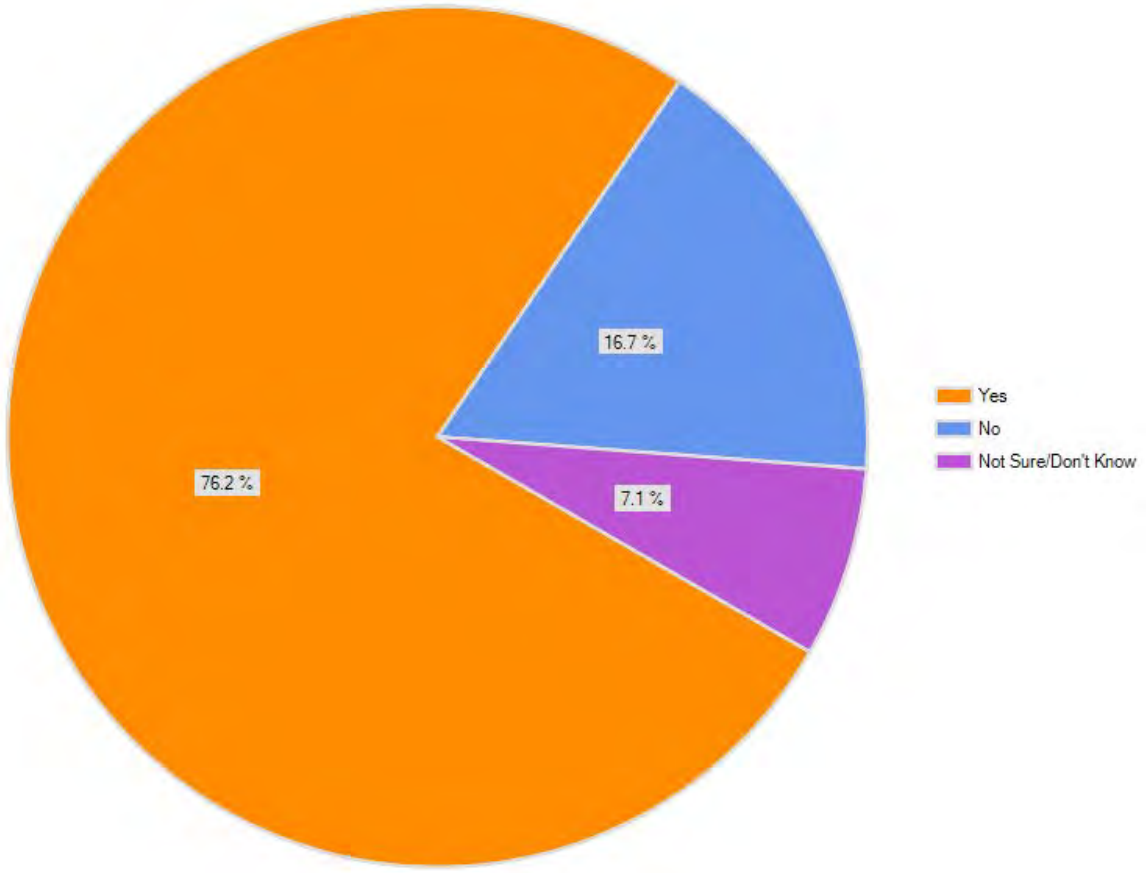


Both survey methods (phone and online) show a high degree of a sense of responsibility among business and community leaders with regard to the need for business and industry to do more toward energy conservation (95% online vs 76% phone).

The combined level of agreement on this issue between both survey methods shows strong support for the need for business and industry to develop plans for better energy conservation.

This high degree of awareness and acknowledgement of responsibility will be helpful should the Yukon Energy Corporation consider a future energy conservation program that requires the support and engagement of industry, business and community leaders.

7. Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?

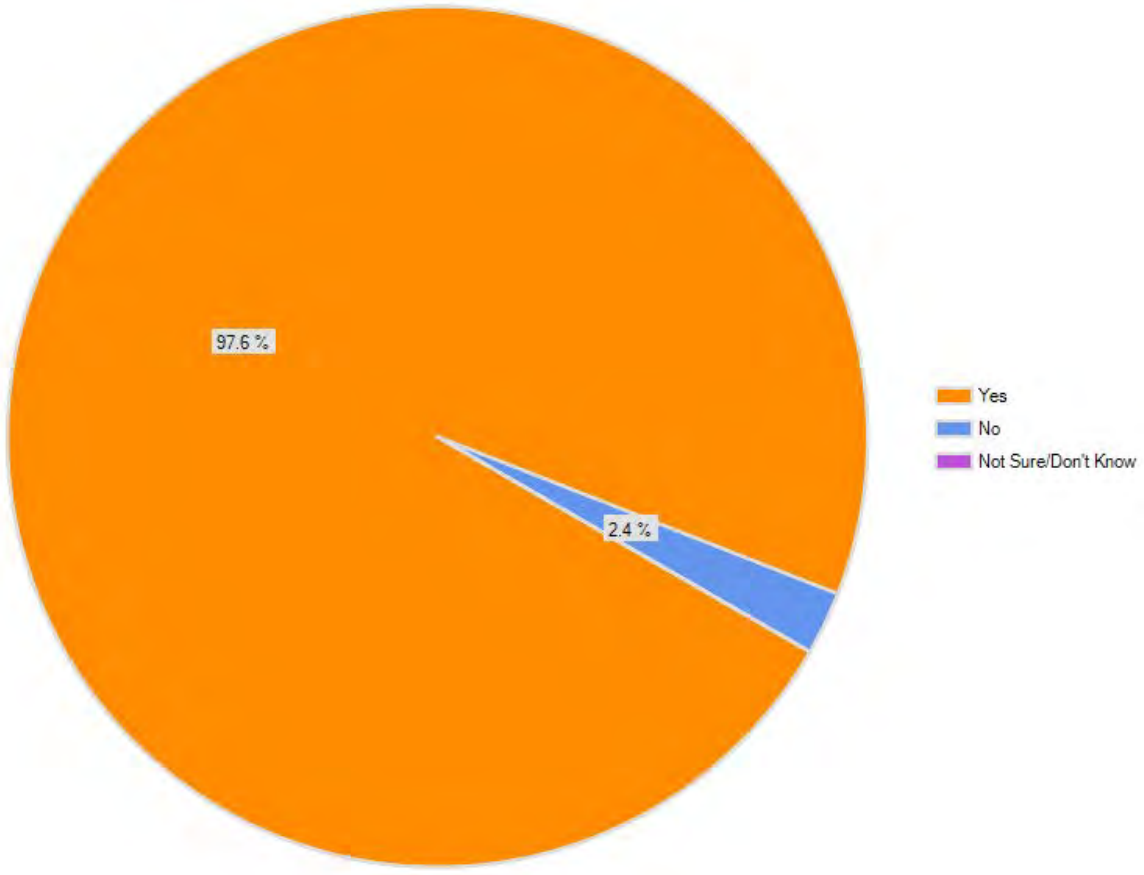


Consistent with the high degree of support for energy conservation measures, community and business leaders are also very supportive of continuing to develop clean energy sources in combination with new hydro sources.

The phone and online surveys showed 84% and 76% support respectively for developing new clean energy sources (described as wind and geo-thermal).

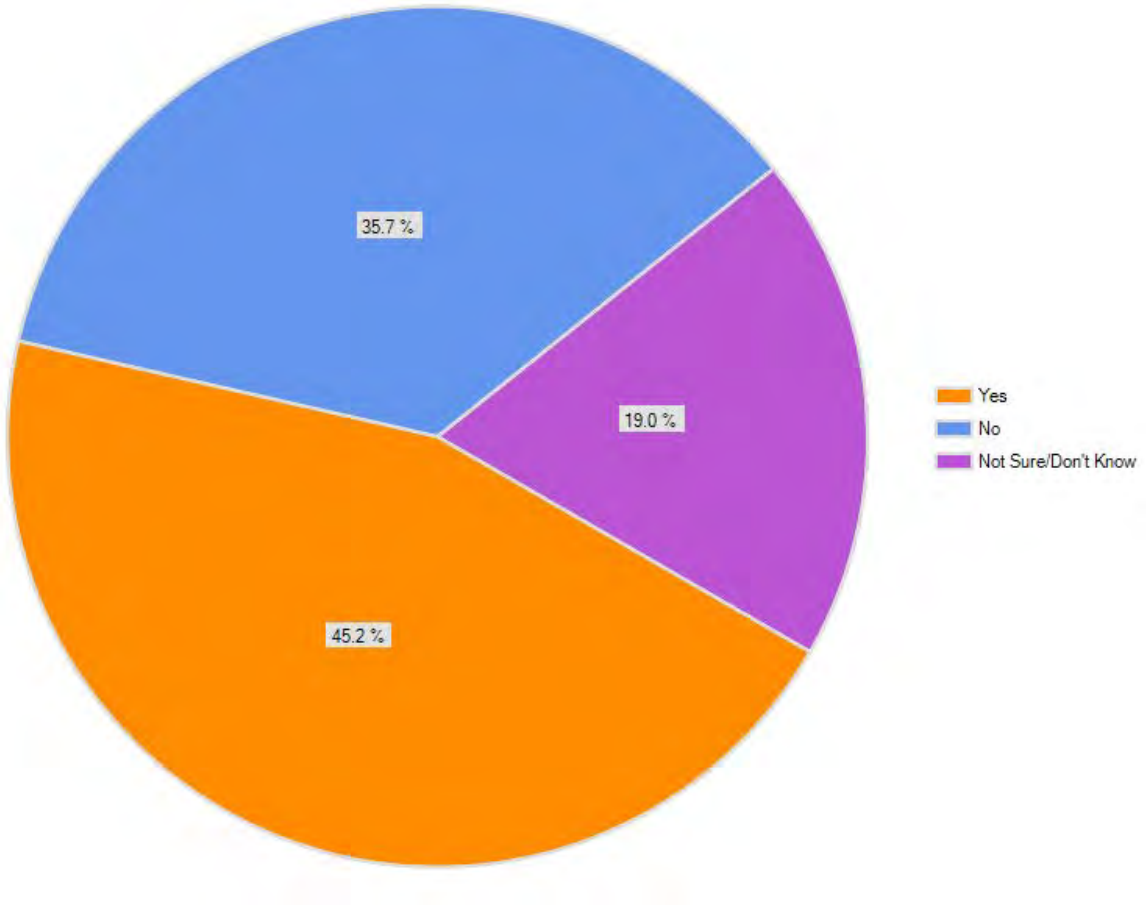
Note: Open comments collected through the survey suggest some felt the description of “wind and geo-thermal” was too narrow to represent alternative energy.

8. Is moving away from a reliance on diesel-generated power the right thing to do?



The view that Yukon should be moving away from the use of diesel-generated power is consistent between community leaders and the public. Several comments from community and business leaders however, recognize the important role diesel-generated power plays in smaller communities and as a back-up system

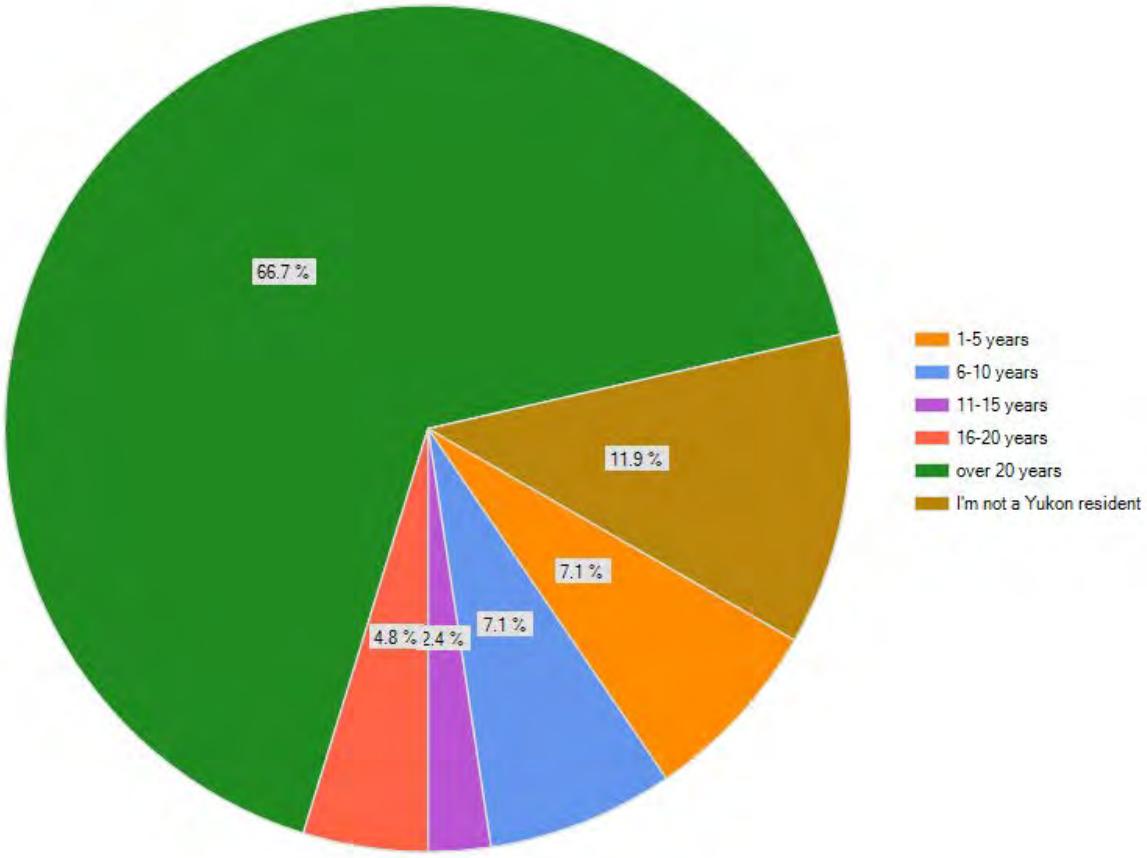
9. Do you have confidence in the Yukon Energy Corporation to plan and develop clean energy sources to meet future demands?



While community and business leaders support the development of clean energy sources, less than half of those surveyed (45%) say they have confidence in the Yukon Energy to plan and develop new clean energy. The confidence level indicated in the phone survey showed a slightly higher level of confidence at 56%. Using both data sources suggests about half of community business leaders have confidence in the corporation in this area.

> Note: Question 10 asked respondents to identify what they felt was the 'most important' thing the Yukon Energy Corporation needs to consider regarding Yukon's future energy needs. See Appendix B for verbatim comments.

11. How many years have you been a Yukon resident?



Consistent with the phone survey of community and business leaders, two-thirds (67%) indicated they have been a Yukon resident for over 20 years. This length of residency provides a strong historical perspective and experience in relation to Yukon energy issues.

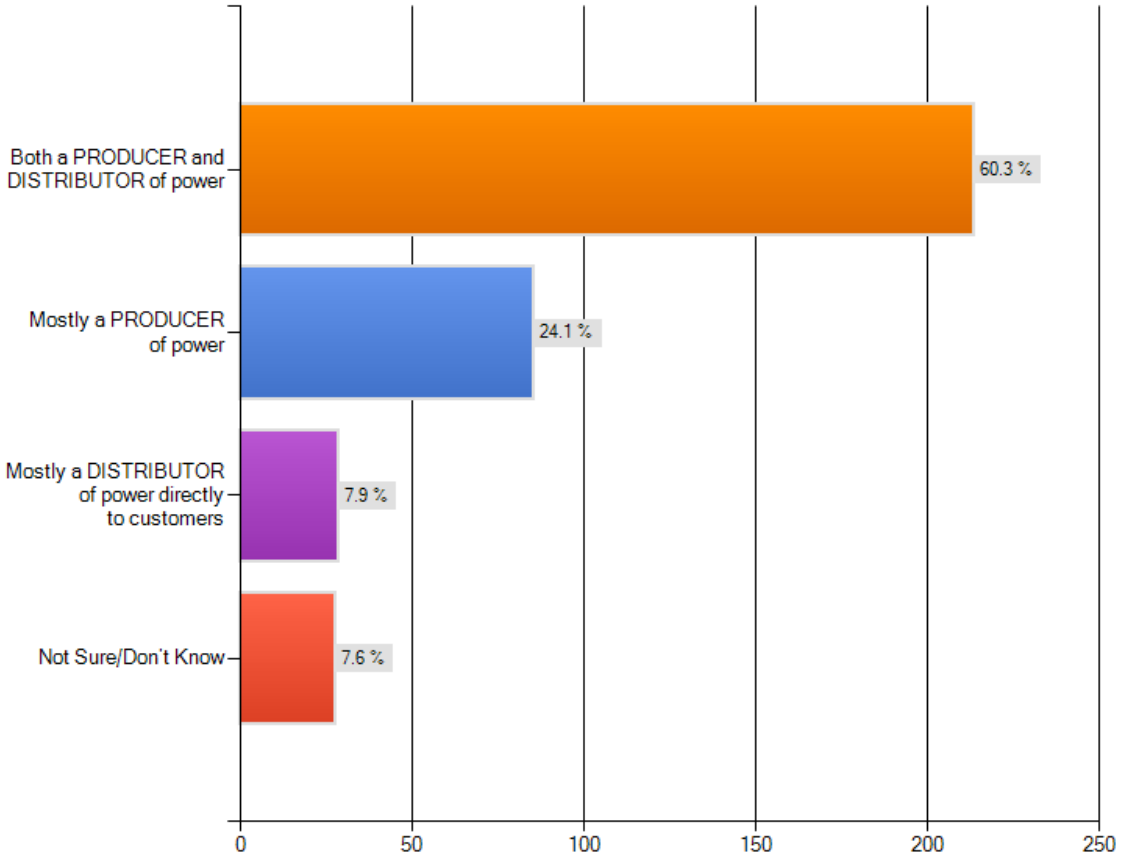
> Note: Twelve per cent (12%) of the community and business leaders who were sent an email invitation by the corporation to participate in the survey indicated they are not Yukon residents.

SECTION IV
Findings from the Public Online Survey

Introduction

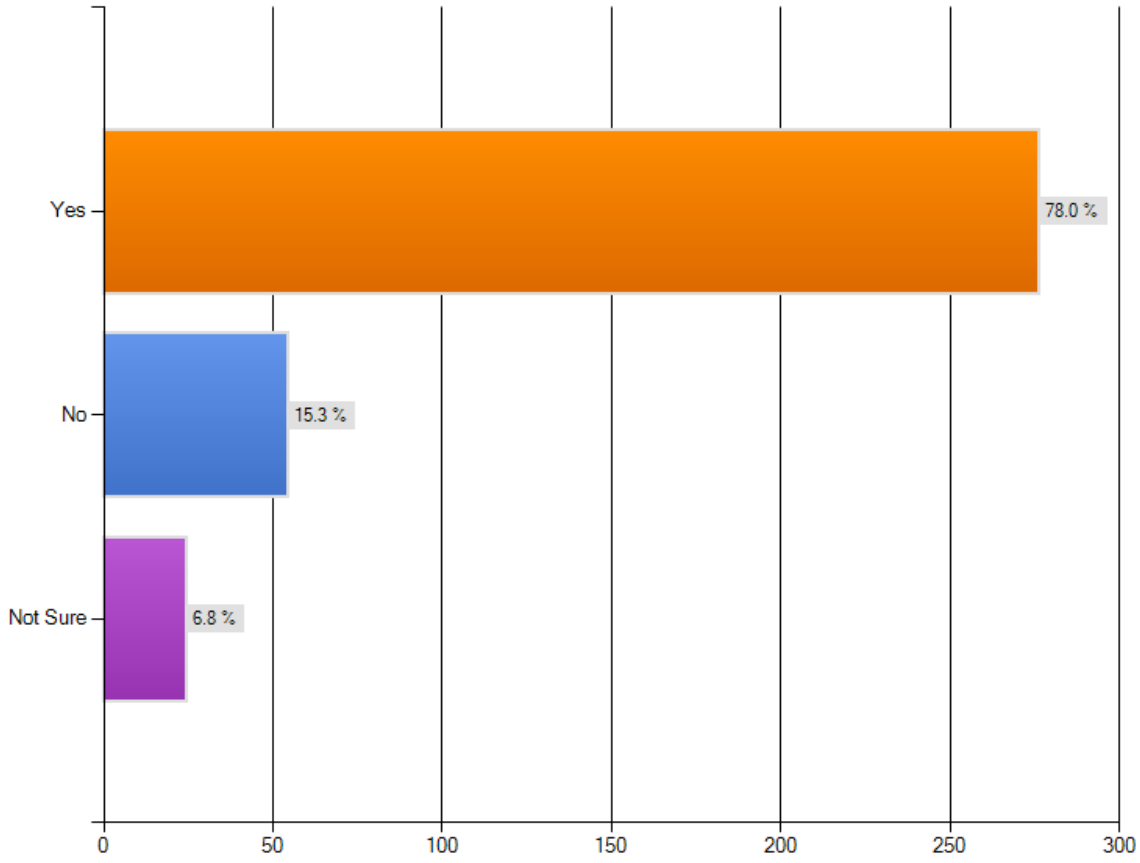
An open online survey of Yukon residents was conducted between June 15 – July 1, 2010. The survey was promoted through social and mainstream media and the Yukon Energy Corporation website. An incentive was offered to increase participation. The target of 180-200 respondents was surpassed at 356 participants. The survey achieved a 93% completion rate which means of the 356 who started the survey, 330 completed and submitted the survey.

1.1 Which of the following best describes the Yukon Energy Corporation.



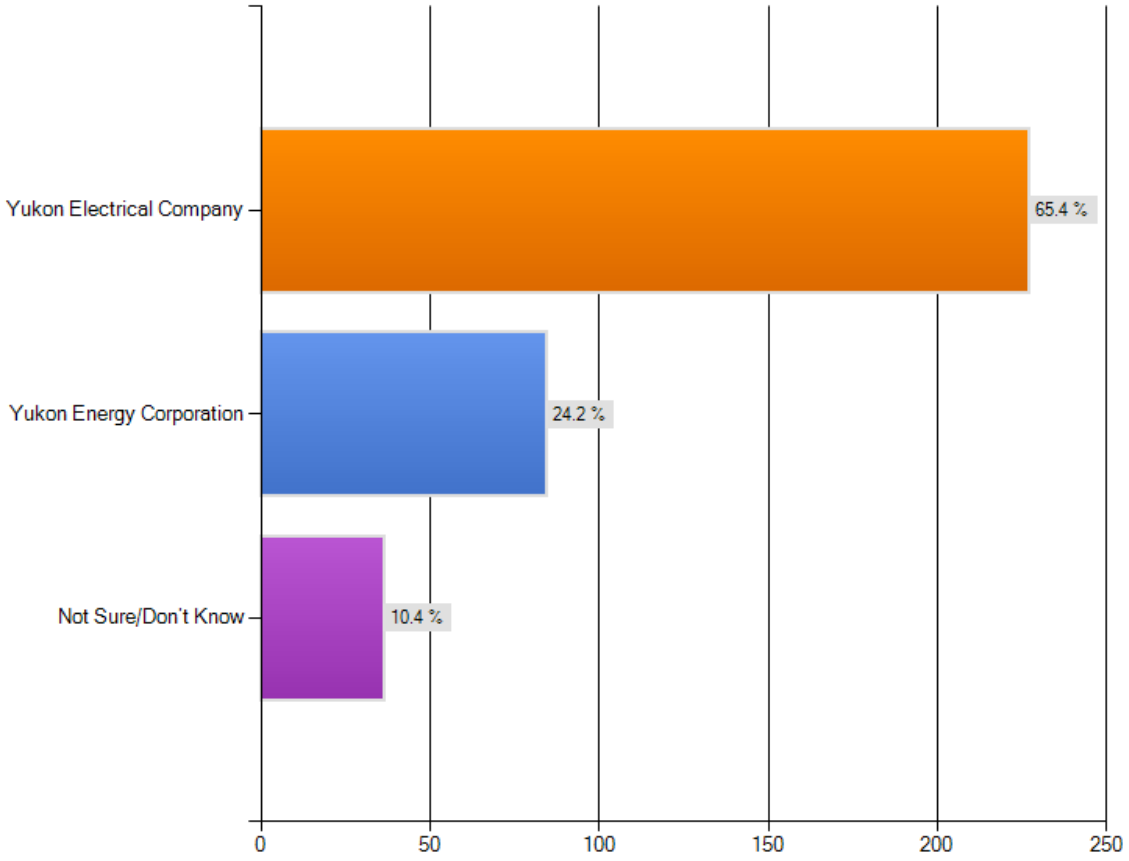
Just over fifteen per cent (15.5%) of Yukon residents indicated they either did not know (7.6%) the primary function of the Yukon Energy Corporation or thought the corporation primarily distributed power (7.9%). The majority (60%) of respondents are aware the corporation has a dual role of producing and distributing power and almost one-quarter (24%) said the corporation is mostly a producer of power.

1.2 Is it important to you to know who PRODUCES power and who DISTRIBUTES power in the Yukon?



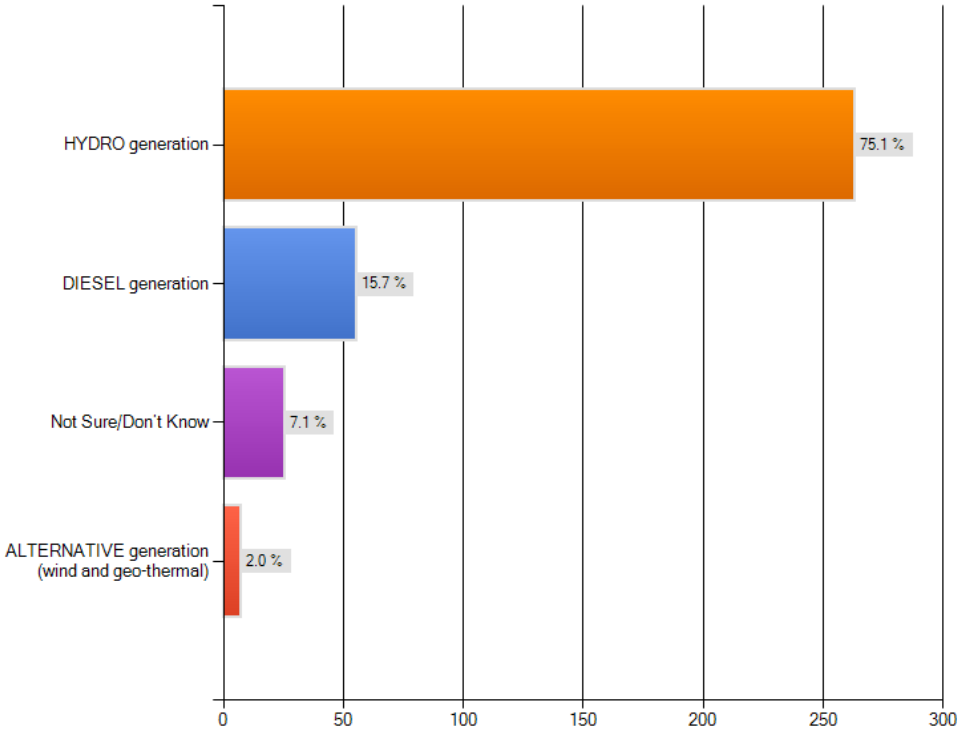
Seventy-eight per cent (78%) of Yukon residents said it is important to know who produces power versus who primarily distributes power. Clarity about the corporation's mandate may be a consideration for future public communications.

1.3 Who would you most likely call to report a power outage?

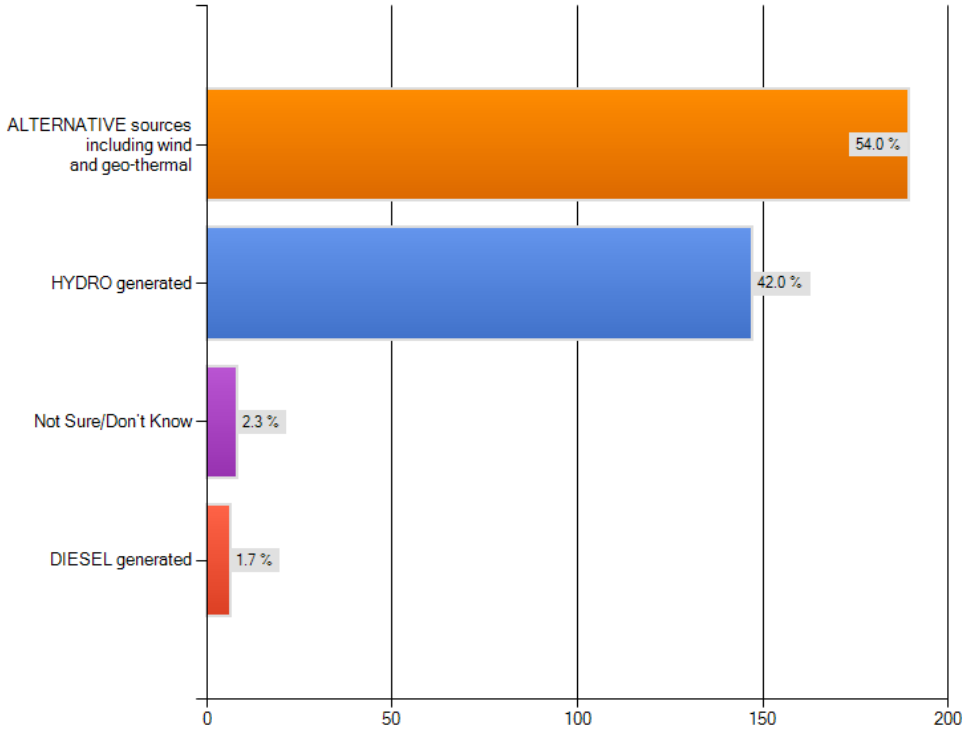


In assessing responses to the question of who to call to report a power outage, it is important to recognize that respondents included communities where the Yukon Energy Corporation is both the producer and supplier of power. It is also important to note the majority of survey respondents were Whitehorse residents and see the Yukon Electrical Company as their supplier and therefore the company they would call to report a power outage.

2.1 Which generates the MOST power in meeting Yukon's energy needs?



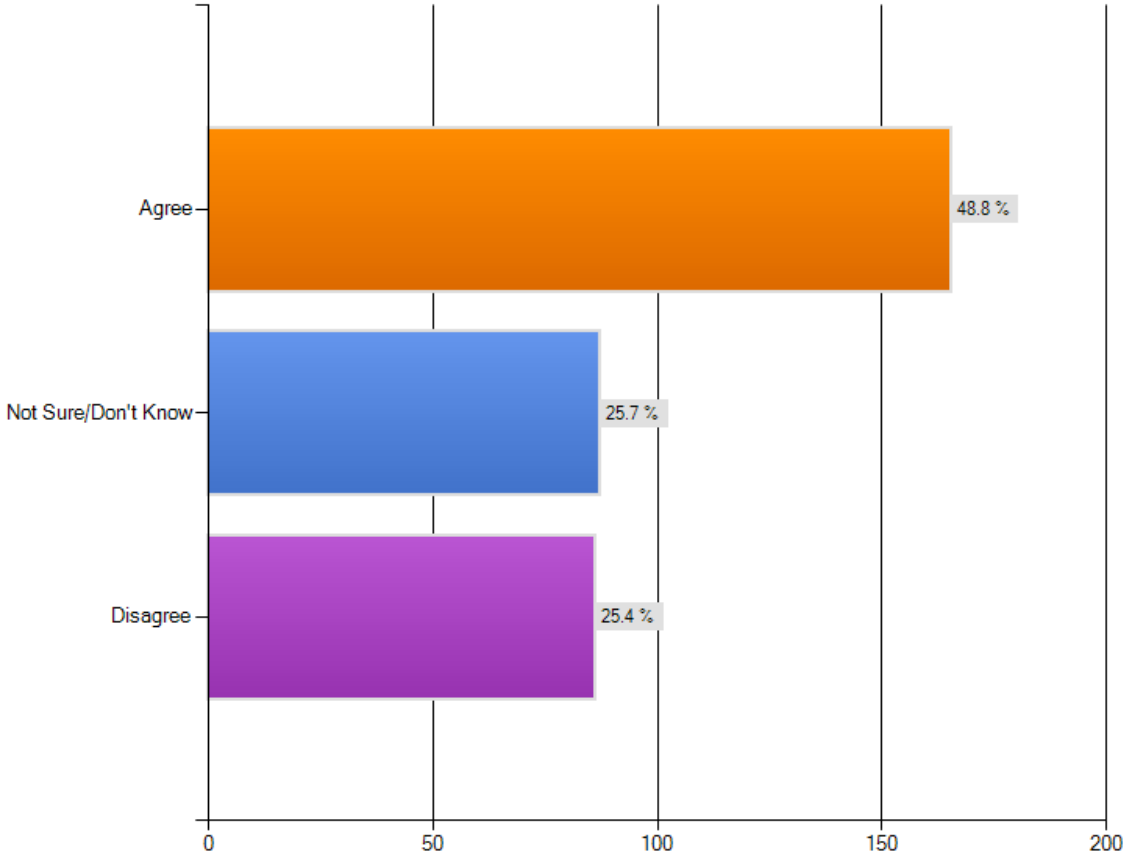
2.2 If you could choose how the power you use is generated, which would be your PREFERRED choice?



Three of every four (75%) Yukoners are aware the majority of their energy is generated by hydro, and over half (54%) would prefer to get their power from alternative sources if it were an option.

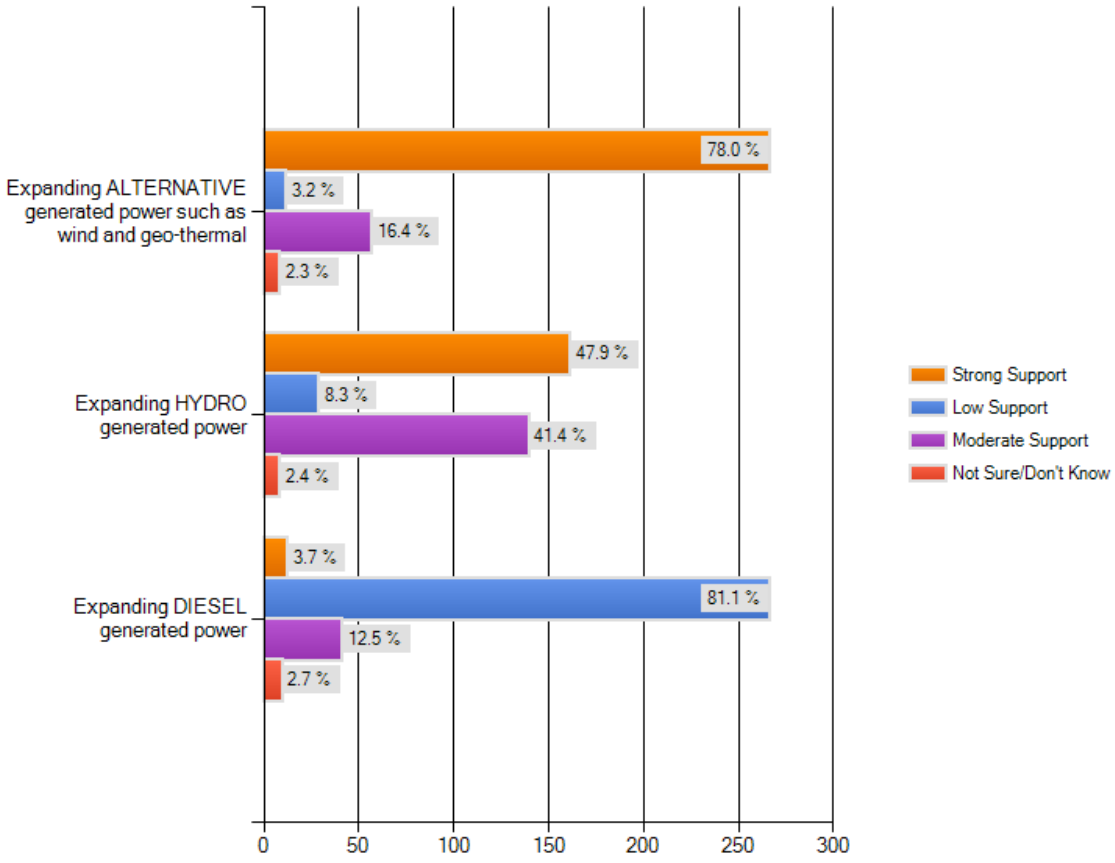
Note: No cost factors were included when survey respondents were asked to identify their "preferred choice". For the purposes of analysis, it is assumed that – all things being equal – respondents answered this question with an understanding that, when asked to compare, the cost of alternative source generated power would be the same as hydro generated power.

3.1 At the current rate of growth in power production, Yukon will not have enough power to meet future needs.



Almost half (49%) of Yukoners agree with the position that action needs to be taken to ensure Yukon's future energy needs are met if the current rate of growth continues. An equal number (25%) said they disagreed with this statement and a equal number were not sure of the accuracy of the statement.

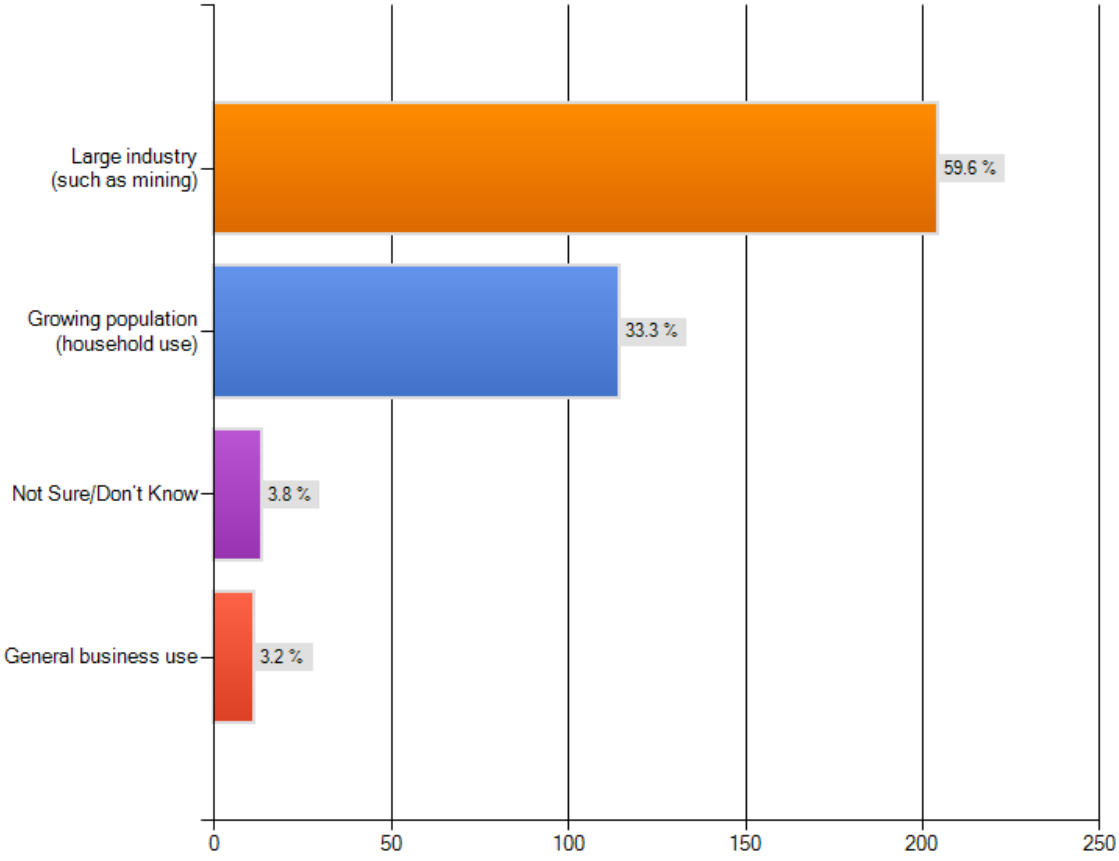
3.2 What level of support do you give each of the following power generation options?



A strong majority of Yukoners (78%) clearly favor expanding alternative generated power sources and are 81% are not in favour of expanding diesel-generated power. Slightly less than half (48%) indicated strong support for hydro generated power with an additional 41% giving moderate support to hydro power.

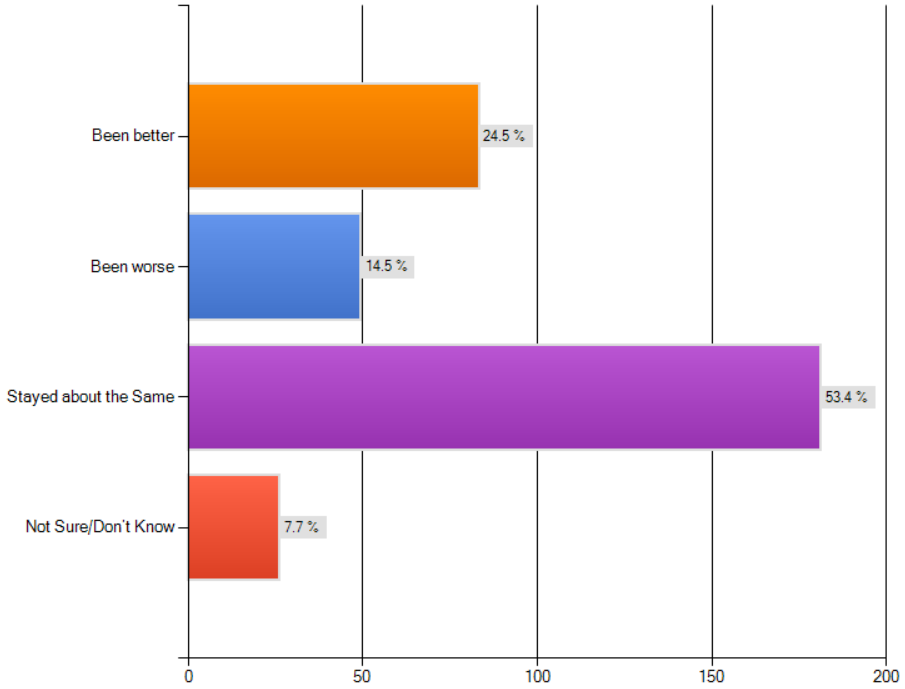
No development related costs were attached to the various power generation options, therefore alternative sources should be viewed as an “ideal” for most Yukoners. Factors related to cost, distribution, availability and reliability are all key to developing a fuller understanding of where Yukoners stand on alternative versus other energy sources.

3.3 Which of the following will create the SINGLE GREATEST DEMAND on Yukon's future energy needs.

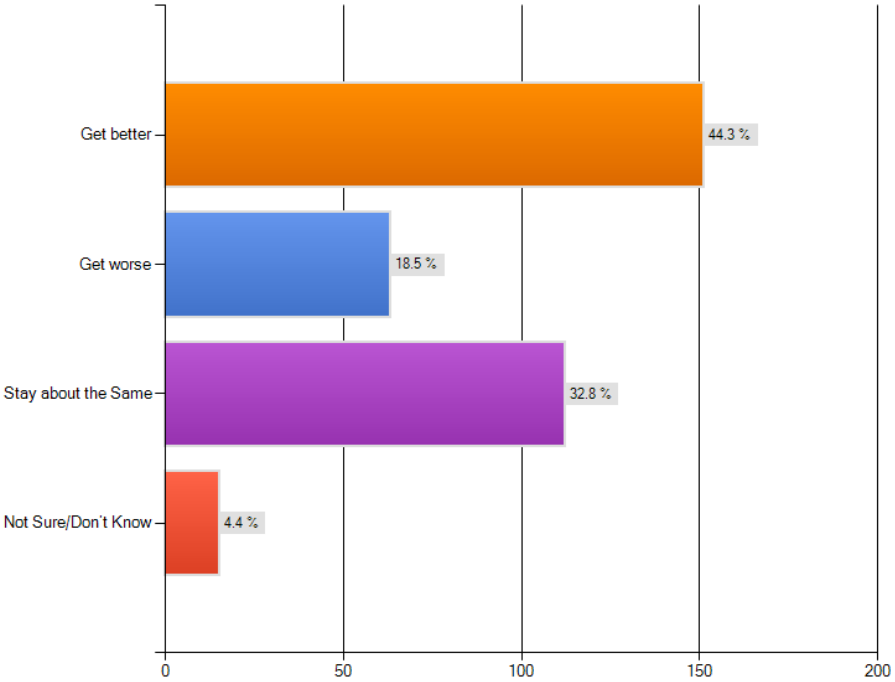


A majority of Yukoners (60%) see large industry as the big driver when it comes to meeting future energy needs while fully one-third (33%) see the growing population and related household use as being of greatest impact.

4.1 Over the past 12 months, reliability in the supply of power has:

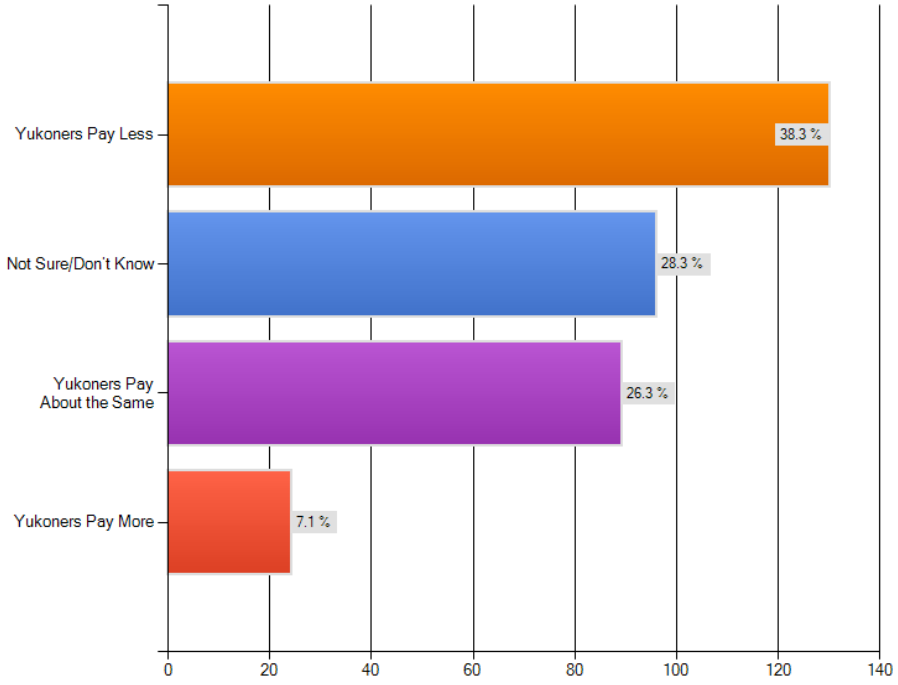


4.2 In the next 5 years, I expect the reliability of power to:

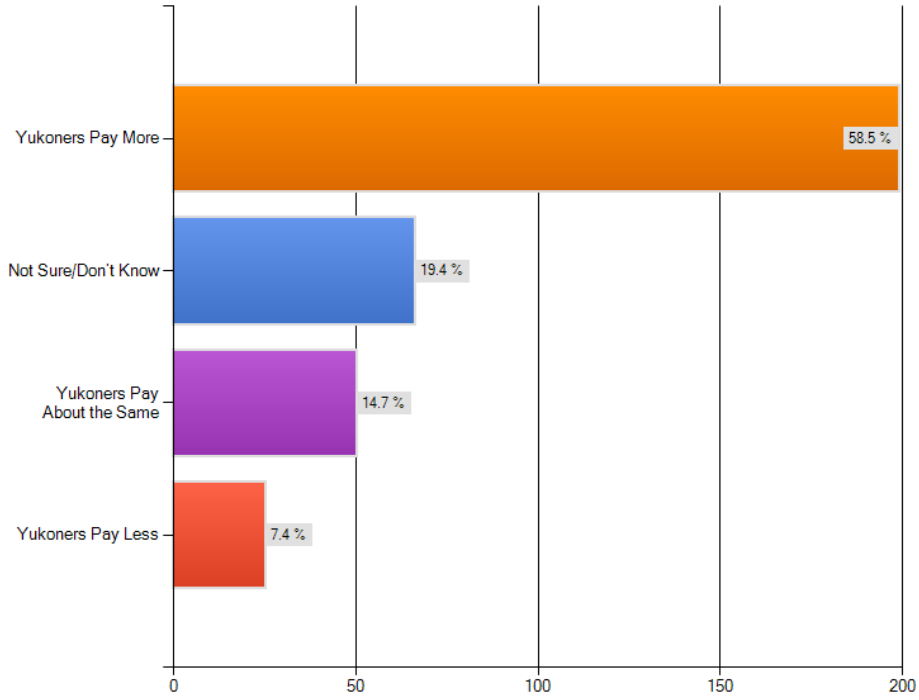


A slight majority (53%) of Yukoners feel the reliability of their power supply has remained about the same over the past 12 months, and 44% feel that the reliability is going to improve in the next five years. One-third (33%) expect no change in reliability. Just under 15% of Yukoners said reliability worsened over the past 12 months and just under 19% feel reliability will continue to get worse over the next five years.

4.3 Do you think Yukoners pay MORE, ABOUT THE SAME or LESS for power as compared to what residents in the NWT and Nunavut pay?

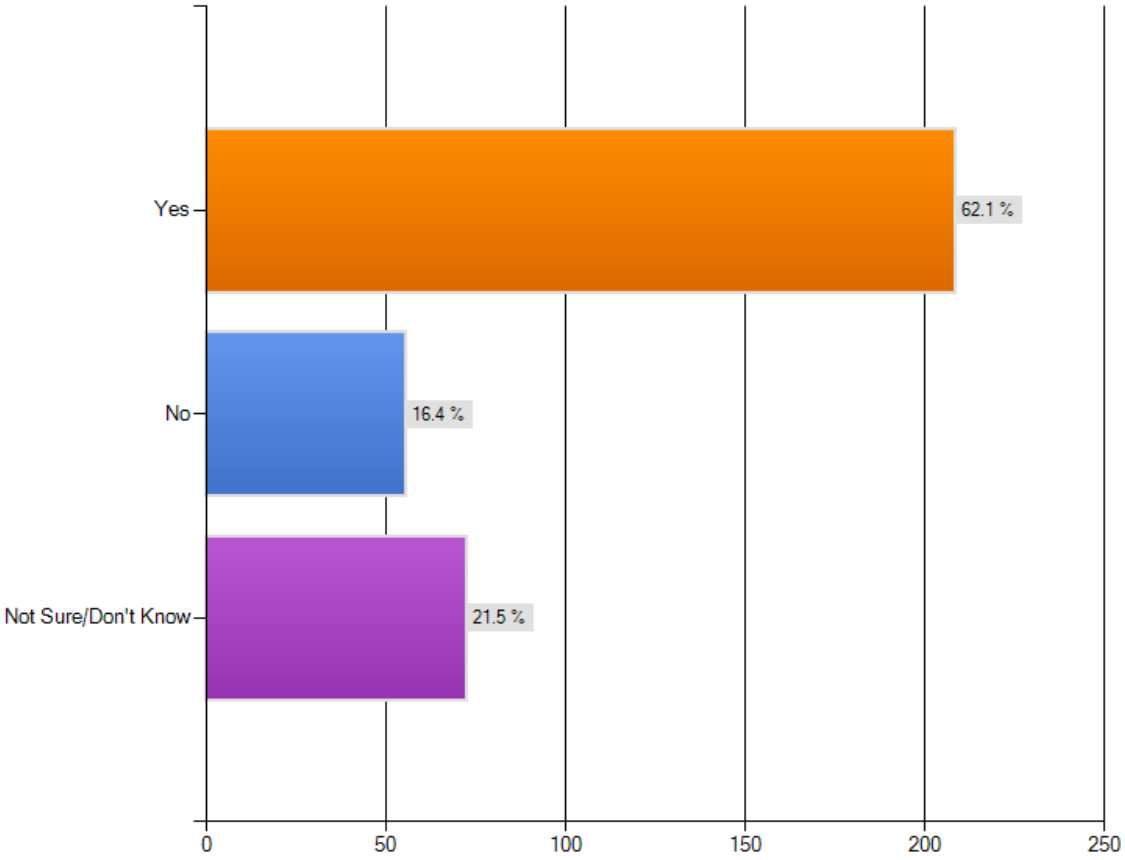


4.4 Do you think Yukoners pay MORE, ABOUT THE SAME or LESS for power as compared to what residents of Edmonton pay?



With regard to the perception of how much Yukoners pay for power relative to their northern neighbours in the NWT and Nunavut and residents of Edmonton, almost two-thirds (65%) said they pay the “same or more” than other northerners and an equal number (66%) said the pay the “same or less” than residents of Edmonton. This indicates a general sense that power costs more in the north than in southern regions.

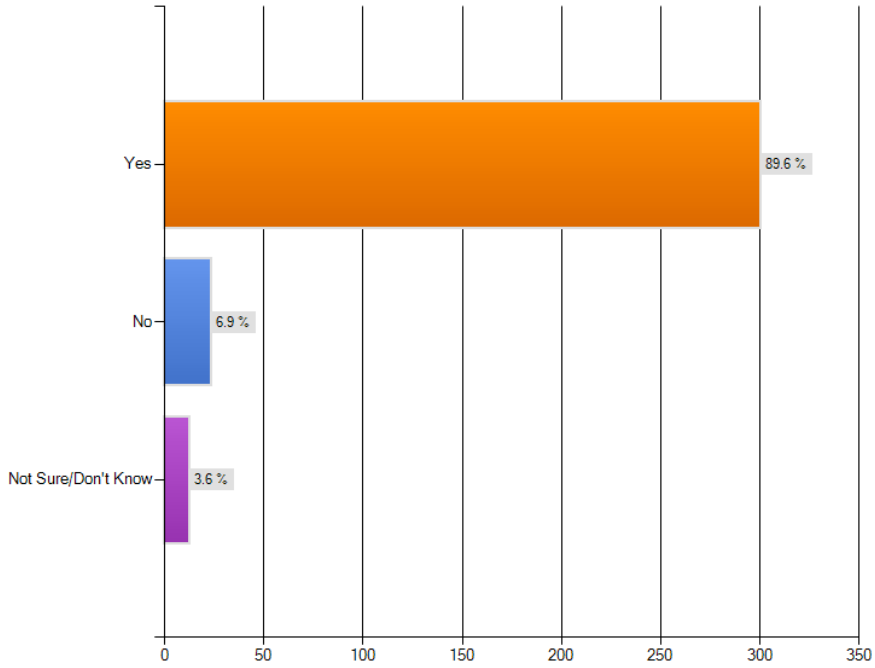
5.1 Do you have confidence in the Yukon Energy Corporation to plan and develop clean energy sources to meet future demands?



Over 60% of Yukoners said they have confidence in the Yukon Energy Corporation’s ability to effectively plan and develop clean energy sources to meet future needs. This is slightly higher than those who responded to the telephone survey where 58% said they have confidence in the corporation. Of important note is that between 18% (phone survey) and 22% (online survey) were unable to state their confidence or lack confidence in the corporation’s ability.

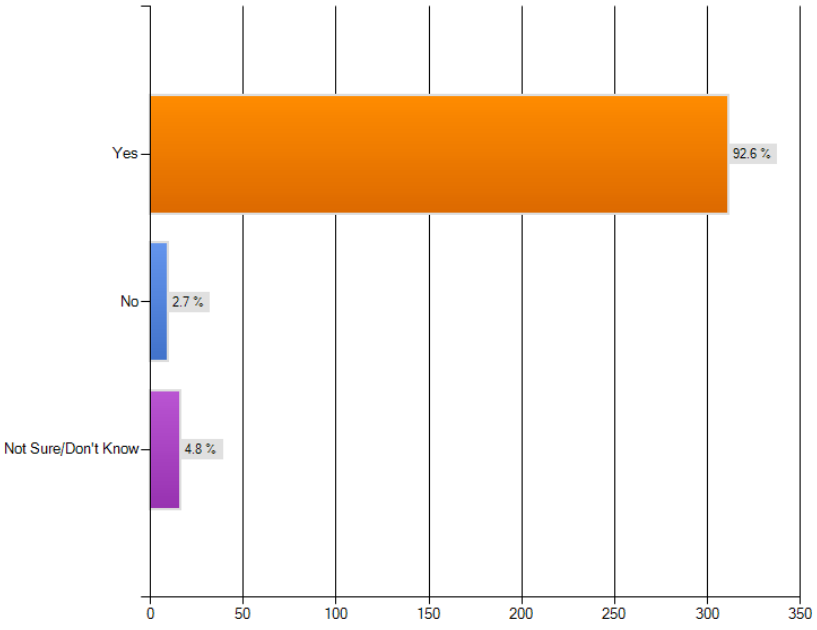
The results reflect an opportunity to improve overall confidence levels.

5.2 Do Yukoners need to do more on a personal level to conserve energy use?

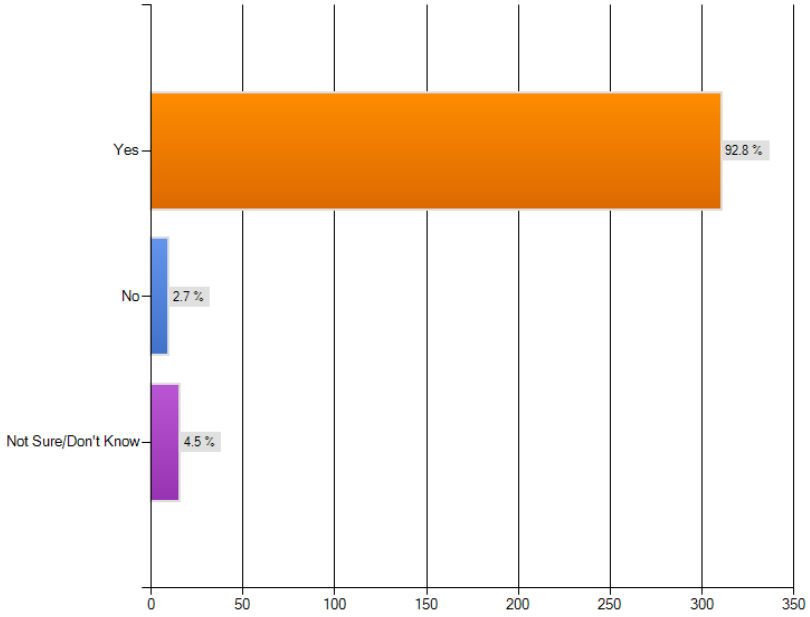


A high percentage (89%) of Yukoners agree they need to do more on a personal level to conserve energy. Response rates to this question were identical in both the online and phone surveys. This indicates a key opportunity for educating and assisting Yukoners in becoming better energy consumers. Ninety-three percent say business and industry needs to do more to conserve energy indicating energy conservation is seen as a shared responsibility.

5.3 Do business and industrial users need to do more to conserve energy use?

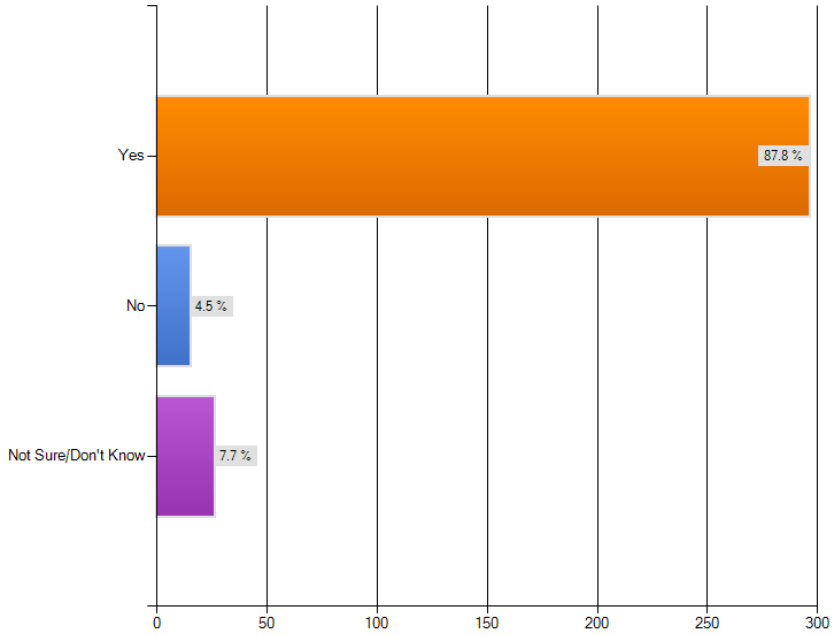


5.4 Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?



Almost 93% support for developing alternative energy sources is consistent with a previous question that showed 78% strong support and 16% moderate support (94% combined strong/medium support) for the development of alternative energy sources in addition to new hydro sources. This indicates a very strong desire for the Yukon Energy Corporation to pursue development of alternative energy sources as the corporation moves forward with larger scale hydro development to meet future needs.

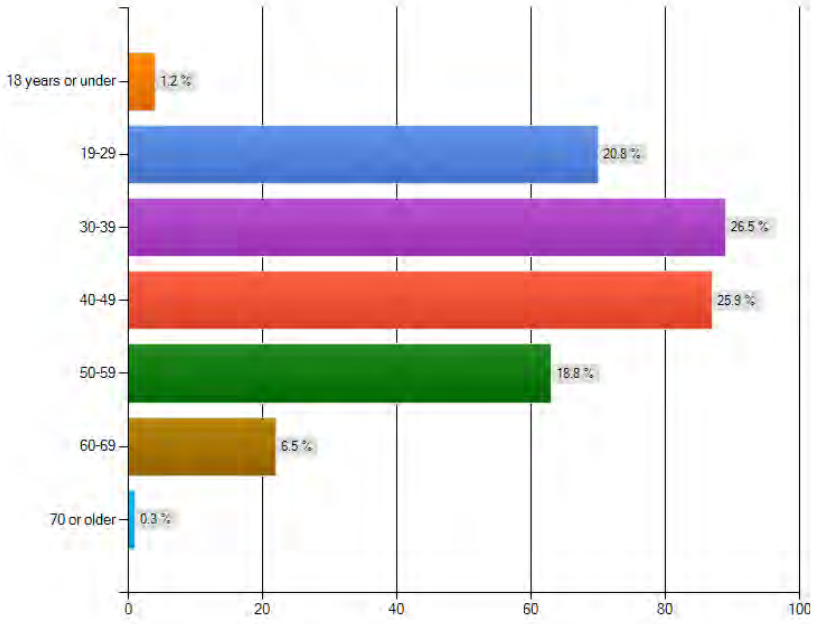
5.5 Is moving away from a reliance on diesel-generated power the right thing to do?



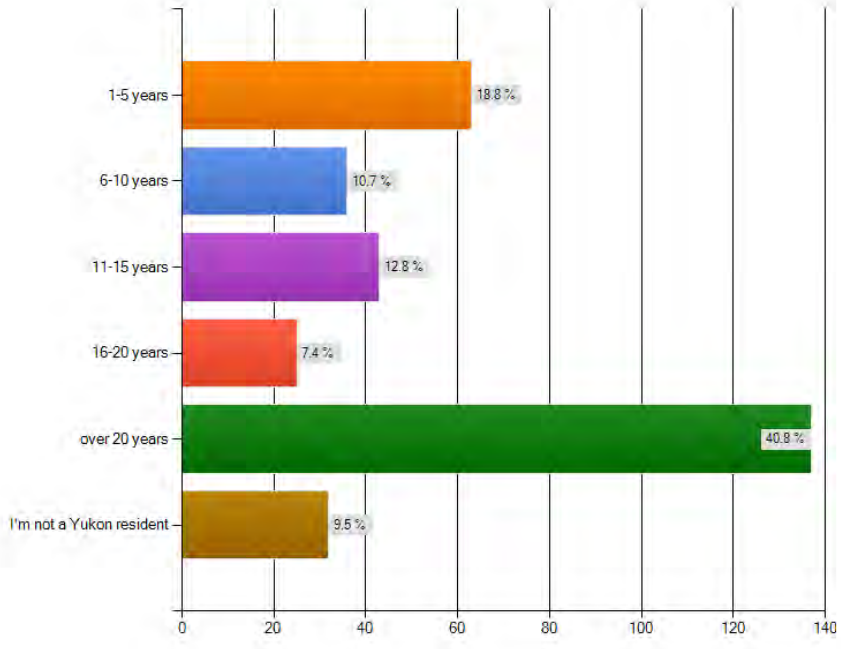
Consistent with support for the development of alternative energy, Yukoners also see diesel-generated power as the least desirable energy source with 88% agreeing that moving away from this source of power is desirable. Comments from the survey however, also indicate an understanding among some respondents that diesel is necessary in some communities and that it provides an important back-up system.

Online Survey: Demographic Data

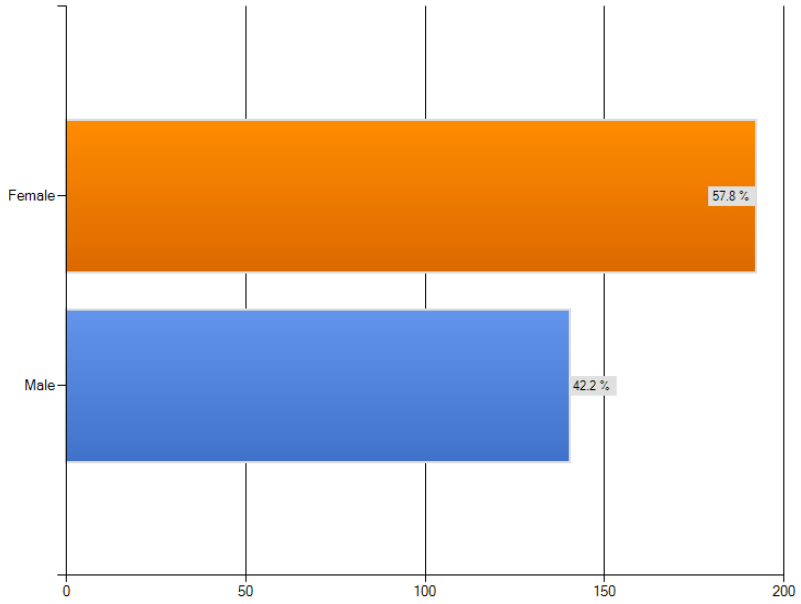
Respondents by age grouping.



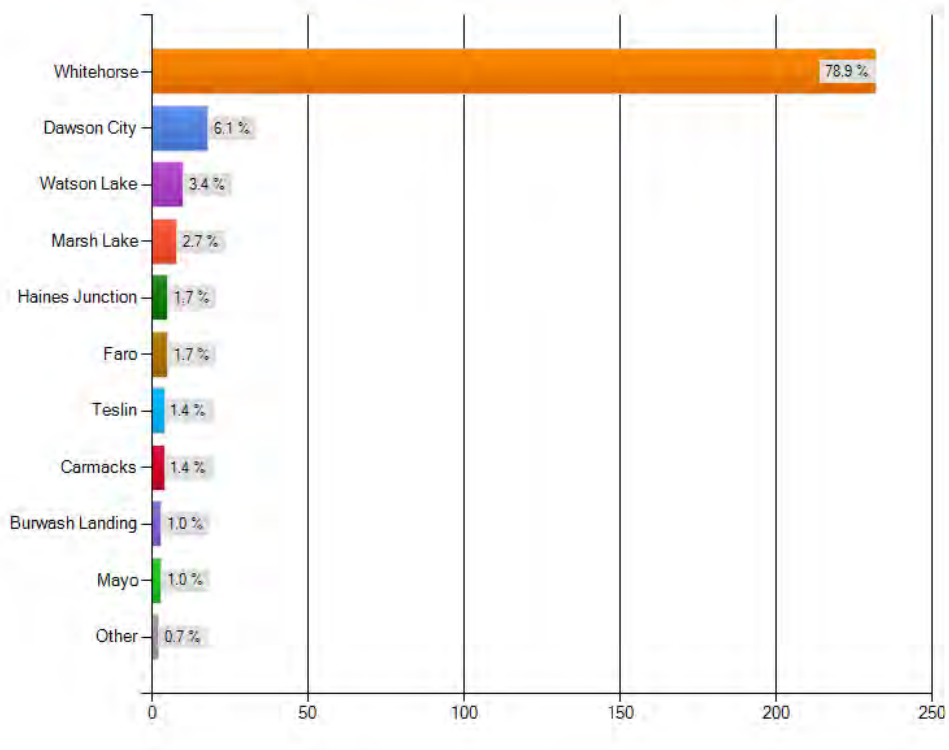
Length-of-residency in Yukon.



Respondents by gender.



Respondents by community.



APPENDIX A
Knowledge, Awareness and Opinion Research Overview

Public Telephone Survey:

Conducted:	June 2 – 8, 2010
Sample Size:	184
Selection:	Random
Surveyed Communities:	(6) Whitehorse , Marsh Lk., Teslin, Carmacks, Haines Jct., Dawson City

Public Online Survey:

Conducted:	June 15 – July 1, 2010
Sample Size:	356
Completion Rate:	93%
Selection:	Open, web-based, promoted via media/social media
Communities:	17 (Yukon) 20 (non-Yukon) (326 = Yukon residents: 30 = Non-residents)

Community and Business Leaders Telephone Survey:

Conducted:	June 4 – 11, 2010
Sample Size:	25
Selection:	Client/Agency Consultation
Communities:	(5) Whitehorse; Mayo; Faro; Watson Lk.; Champagne-Aishihik

Community and Business Leaders Online Survey:

Conducted:	July 7 – 15, 2010
Sample Size:	41
Selection:	Email invitation
Response Rate:	82%
Completion Rate:	100%

Total all Methodologies:	**606**
Confidence Level:	**95%**
Confidence Interval:	**4**

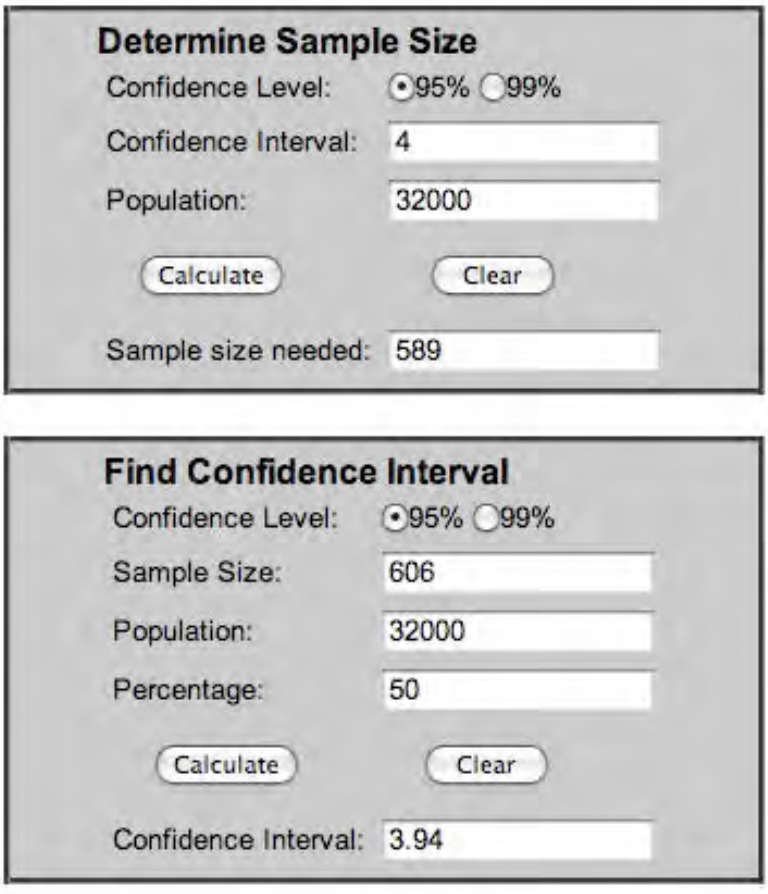
See following page for description of sample size calculation for confidence interval and confidence level.

Sample Size Calculation:
Confidence Interval and Confidence Level

The **confidence interval** (also called margin of error) is the plus-or-minus figure usually reported in newspaper or television opinion poll results. For example, if you use a confidence interval of 4 and 47% percent of your sample picks an answer you can be "sure" that if you had asked the question of the entire relevant population between 43% (47-4) and 51% (47+4) would have picked that answer.

The **confidence level** tells you how sure you can be. It is expressed as a percentage and represents how often the true percentage of the population who would pick an answer lies within the confidence interval. The 95% confidence level means you can be 95% certain; the 99% confidence level means you can be 99% certain. Most public opinion research uses the 95% confidence level.

When you put the confidence level and the confidence interval together, you can say that you are 95% sure that the true percentage of the population would have answered the question in the same way as indicated in the obtained survey responses within an 8% range. The wider the confidence interval you are willing to accept, the more certain you can be that the whole population answers would be within that range.



APPENDIX B

Verbatim Comments: Business and Community Leaders Online Survey

Following are verbatim comments from the community leaders online survey. The survey was conducted in July 2010. Approximately 50 community and business leaders were invited by email to take the survey with 41 (82%) participating. Completion rate was 100% meaning that everyone who started the survey completed the entire survey.

Comments should be viewed in conjunction with the statistical data for these questions.

Author's Note: While the survey comments below are presented verbatim, some have been edited to ensure confidentiality including the removal of any names, personal references or identifiers.

Q 6. Should business and industrial energy users be developing plans to use better energy conservation technologies, equipment and operational practices to help reduce demand?

1	The best energy conservation policy is charging what it really costs to generate power as well as expand generation capacity.
2	Need a rate structure to give off-peak hour use
3	The high price of power in the Yukon ensures that users are already focusing on this; I do not believe that further studies would be cost effective.
4	i think govt and its depts need to lead the way on this.
5	New power sources are expensive and some energy conservation should be employed.
6	Power should be more affordable
7	government should not always feel the need to subsidize energy for mines. if the mine can't afford to create its own energy or pay a fair price its not viable
8	Higher efficiencies are good as they save businesses money and reduce demand, however there needs to be support for using electricity as an energy source as it's clean and easy to use. Don't penalize companies for wanting to use electricity.
9	All businesses and industries should be trying to conserve and reduce energy use.
10	this is a stupid question. Any business will try to achieve economies wherever they can.
11	no
12	Obviously better development planning and lowering costs should improve the bottom line.
13	Turn computer off, turn lights off, power electronic devises down.
14	Business and industrial users will respond to costs...if demand costs dictate conservation, then conservation will happen. Otherwise, it will not. So, structure the rates accordingly.
15	Only as long as costs do not get out of hand.
16	Of course, only a fool would say no to this.
17	But it has to be at a reasonable cost...we all have our own contributions to make to the overall energy challenge in Canada as a whole.
18	Time-of-day metering (cheaper rates at low demand times/seasons). Permit homeowners and business to generate power (solar panels, wind, etc.)

Q 7. Should Yukon continue to develop alternative energy sources such as wind and geo-thermal in combination with new hydro sources?

1	Consider Natural Gas
2	Alternative energy sources will never provide base load generation but they should be developed as a companion to expansion of base load capacity
3	Geothermal – Yes. Wind -No
4	Where they are cost competitive. Alternative energy sources must be cost competitive - considering both capital and operating costs and effective utilization
5	2 things; i believe we need to be interconnected to the north American grid - expand the lines south, not north. and are we not able to look at natural gas generators instead of diesel?
6	Some forms of alternative energy will provide a cost-effective method of meeting new generation requirements and improve electrical grid stability and reliability as well as keep more of our ratepayer's money in the Yukon
7	maybe geothermal but so far the wind energy at heckle hill is a failure
8	Geothermal may be an option. Yukon Energy hasn't explained to the public enough of what's happening in regards to geothermal. Wind energy I do not support in combination with hydro.
9	Wind power in the Yukon has been a joke. Not sure about geo-thermal Hydro if it makes sense. LNG makes a lot of sense. Natural gas turbine plant makes sense
10	Absolutely not, unless these are the most economically viable energy sources. So called alternate energy sources should not be subsidized by the rate-payer nor the taxpayer. It is a waste of limited economic resources. It is a boon only for utilities (receiving taxpayer and ratepayer subsidy).
11	Hydrogen. The key is not generation but storage, effort should be directed at storage research/solutions
12	no
13	If either wind or geothermal sources can be cost effectively developed and operated and not just token efforts to keep the greenies happy, then certainly. YEC should be run as a business and its' decisions should make economic sense.
14	We don't use enough, more wind for sure
15	Not until it is cost effective. At present, I don't believe that it is so.
16	Costs are the limiting factor with these alternatives. What about natural gas?
17	If it is feasible and affordable, of course.
18	They tend to be very high cost and not generate a lot of power so looking at them for a solution to the energy challenge for large industrial operations is probably quite impractical
19	where economically feasible

Q 8. Is moving away from a reliance on diesel-generated power the right thing to do?

1	Yes. However they do provide much needed back up
2	Petroleum fuels are a limited resource and continue to escalate in cost whereas renewable projects have fixed costs and do not rely on depleting resources
3	lets be realistic. sure its the right thing to do but only if and when its cost effective
4	But not entirely, particularly in the remote areas. Some diesel-generated capacity is also necessary for standby emergency purposes.
5	Need diesel as a back up and maybe remote communities
6	Where diesel is the more expensive energy sources we should be looking for other alternatives - like Hydro, clean coal, mini nukes, natural gas from the Dempster. What is most economical?
7	Unless you can economically use the waste heat.
8	Of course, but it should remain as a reliable back-up source.
9	It should incorporate other options such as clean coal and natural gas
10	Where economically feasible

Q 10. What is the ONE MOST IMPORTANT thing that Yukon Energy needs to consider regarding Yukon's future energy needs?

1	Keep energy cost effective
2	Consider clean coal or coal gas generation from the Division Mtn coal field at Braeburn
3	The focus should be on projects which are large enough to ensure a consistent supply with a margin of overcapacity to supply future industrial activities.
4	Need to think about individual customers and not just big industry. i tried calling to speak to someone about outages - no response and no one really cared. i would imagine if i was minto mine, someone would talk to me.
5	Yukon Energy needs to first solicit all of its new power from independent power producers on a take or pay basis as is done in most of the rest of North America. Yukon Energy should stay on to manage the transmission and existing production but should look to the private sector for new energy sources. The Mayo B project is an example of the high cost of new utility-based projects. This load requirement should have been put out to the private sector first
6	Developing alternate source of energy such as Hydro, Wind power etc.
7	Bring in Power to support mining development. There are major deposits in Yukon that could be developed if power was available. This would create a lot of jobs and wealth for Yukon. These developments are not likely to proceed unless the power situation improves.
8	Cheap long term power
9	Greenhouse gas
10	Complete a grid of all yukon/northern bc
11	I don't think government or government corporations are agile and creative enough private sector will provide energy solutions in the future as energy becomes more expensive.
12	I have confidence that they can deliver the energy. I do not believe Yukon Energy has done a good job or is continuing to do a good job in making the clean energy projects cost effective. Private industry can build it cheaper by far.
13	Location of new / additional power generation infrastructure relative to new industrial developments (e.g. mines).
14	Look at developing a Natural gas Turbine plant. Tie the grid into B.C.
15	Develop our energy needs in the most prudent, economically efficient manner possible. Your job is to develop energy at the lowest possible cost to the rate payer with no subsidy from other levels of government. All other agenda's are someone else's responsiblity. The Mayo B is a travesty. 160 million for 6 megawatts of power is not providing electricity at a very economic price. 26million per megawatt - what a joke.
16	a multi faceted approach which will bring a diversity of options and solutions; the traditional utility model does not do well with uncertain circumstances and the ability to deliver innovative and creative solutions. So, in addition to the traditional consultants, non- traditional creative thinkers/entrepreneurs should be encouraged. Vision will be required
17	Future demand
18	Sustainability
19	Availability of petroleum will become constrained, and cost will increase greatly. Guaranteed.
20	SE Yukon's dependence on diesel
21	Reliability and accountability. That means don't blame every brown out or spike or outage on squirrels and ravens. If the line is 10 metres off the ground and the trees 15 meters tall, the right of way should be cut and maintained so no tree can hit the line.
22	Become self-substainable. Get off of diesel, ridiculous and disgusting, and embarrassing.
23	Reliability, followed closely by affordability
24	Large mines should develop and pay for their own power generation. Yukon Energy Corp should not be involved in short term, large scale projects. It is not their job. If we have excess generation, by all means sell it, but don't develop large-scale projects for short term projects at our risk and expense. Stick to the mandate of providing reliable, affordable power to the Yukon people. This is a simple task if not confounded by mining mega projects that are risky at best. If they are not feasible without grid power, let them wait until they are.
25	Be prepared for future needs by industry.
26	How to derive large energy sources...+50MW...for operations like Casino, Northern Dancer,

	Selwyn...and the Klondike/Rau/Eagle will likely generate new projects requiring clusters of energy
27	Reasonable cost with reliable service.
28	Reliability -- I'm tired of re-setting my clocks every couple of days
29	Let Yukoners invest in the Yukon to promote YEC ie: Like Air North did to get off the ground
30	Clean energy and protection of fresh water.
31	Forays into alternative energy seem hesitant (e.g. wind), and the proposals for private energy producers (micro-hydro, solar, etc.) are restrictive compared to other jurisdictions.
32	cost to customers
33	Stable rates.

APPENDIX C

Verbatim Comments: Public Online Survey

Following are verbatim comments from the public online survey that was conducted between June 15 and July 1, 2010 and achieved 356 responses with a 93% completion rated, meaning that 93% of those who started the survey completed it. In total, residents from 17 Yukon communities participated. In addition, 30 non-residents of the Yukon also participated in the survey.

Of particular note is that 27% of survey respondents took the time to write a comment. Coupled with the high response and completion rates, the number of comments recorded indicates a high degree of interest in the topic of Yukon's energy future.

Author's Note: While the survey comments below are presented verbatim, some have been edited to ensure confidentiality including the removal of any names, personal references or identifiers.

Q . Do you have a comment about Yukon's energy future?

1	One word: Geothermal.
2	I am curious what is happening with the windmills. They don't always seem to be operating. I hope the YEC Board is supportive of alternative energy, including energy conservation.
3	Where any hydro expansion is necessary to meet power demands, it should be accompanied by education campaigns targeted to both private and industrial users on the importance of limiting consumption. While in an ideal world we could expand only with alternative energy sources, we don't seem to be there yet, and Yukoners don't seem to be prepared to foot the bill. Any new hydro undertaking or expansion must be carefully studied, preferably by an independant third party, to ensure that habitat is not being negatively impacted by YE activities or infrastructure. Monitoring of impacted terrestrial and aquatic environments should take place over the duration of the project at a much greater degree than what may be provided for by the water license.
4	Start by promoting conservation.
5	Less of a foot print is the goal. renewable energy is a blessing and we are aware of the technology. We must use it. Geo-thermal has barely been tapped, and it can do so much.
6	Behind door politics, such as (reference removed) trying to sell off part of our assets, should be avoided at all costs.
7	I do not want an unregulated, private owned energy corporation.
8	I hope they have a plan for the future if industry leaves.
9	Sounds like Yukon Energy already knows what to do, just needs Yukoners and the YG buy in! Can't wait to see what happens!!
10	Should promote homestead small scale energy generation and be able to sell excess back to grid.
11	Develop alternative energy
12	Make it more reliable - less unplanned power outages
13	Not at the expense of the environment!
14	Focus on micro-hydro, wind, geothermal and allowing people to generate their own power and sell it to the grid.
15	I am extremely opposed to the idea of clients using less power getting a discount. I installed electric baseboards in my new house as back-up for my woodstove, because I felt it was the greenest option. It does not fit with Yukon Energy's mission & philosophy to reward & encourage people to burn oil for heat. I can see how it would be less of a problem for Yukon Energy, but if you want to build better, healthier communities, this is not the way to do it. I would like to see a lower evening rate. I have no idea of how much that would cost, but it

	may be able to balance the draw better. It would be incentive for people & businesses to make changes and be more aware of their power usage.
17	Natural gas (alternative)
18	What about natural gas?
19	promoting the use of hydro and wind electric is better for the environment and possible for the North. Yet YEC continues to penalize people for choosing this form of green power to heat their homes. YEC has the ability to one day provide hydro power with out the use of diesel to all of us. This should be encouraged, rather than discouraged.
20	I will add my comment here since there seems to be no other place.....I am very dissatisfied with the power we get in whitehorse. Numerous times I have measured the power at my house and it is NEVER 120, always 110 or less. Constant brownouts, power outages make me think I am in a 3rd world country at times. The power supply in the Yukon is substandard in my experience. Hard on equipment, motors, computers etc. It has gotten better in the last year but has a long way to go.
22	hopefully they use the wind as it is always blowing up here but i am no expert on that type of use
23	Question 4 should have an option offering developing alternative energy sources without tying it to new hydro sources. By selecting Yes to agree with developing wind energy etc., by default I must endorse development of new hydro sources. I do NOT endorse new hydro energy sources carte blanche and feel this is a dishonest question.
25	Over dependence on fossil fuels is a major cause of global instability.
26	Because of our geographic location and the associated challenges, diesel power backup of our grid is essential to the safety of all Yukoners,
28	They will do well if we can get rid of the territories dependency on fuel to light their homes etc.
30	Hydro should be expanded where possible and supplemented by large amounts of wind. I feel that wind is the most economical, reliable and realistic clean energy source for YEC to pursue. It may not be available at all times but when it is the reservoirs for hydro can be filling (storing) power for later use. Furthermore, combined heat and power using biomass (our forests) as fuel would make a lot of sense here since when the heat demand is the greatest, the electrical demand also peaks! This would require YEC to sell heat as well as electricity, but it is a large utility that could figure that out as well. Downtown Whitehorse has potential for a district energy system that could be the first consumer of this heat.
33	Yukon is a beautiful, fairly pollution-free place. Reliance on diesel-generated power is unfortunate, as it creates more air pollution. It's fantastic to see new projects like Mayo B being brought in, to help with hydro power generation.
32	sustainable energy is key
33	Quite frankly I have been angry at the exorbatent rates we have been getting - but through our observance of ways to lower our power bills we can tell that if others followed suit they could lower theirs as well - while we need power we also should be more careful how we use it - small/home businesses should also have their rates lower - our small local businesses get bit in the butt every month by a huge amount for power - that a lone closes many of them down - our small local businesses should be thriving rather then closing due to every cent they make going to the power and phone bills. etc. If you can't make any money then how can your business survive ..... we all need to eat and pay the bills!!!! The power is the worst of it!
34	Do everything they can to get away from Diesel .... the cost will be too high
36	Be realistic and yet think of the people who live there. To help people with their health and the environment.
37	it's time to accept the reality of our situation. time to change our ways. time for clean, efficient, affordable energy systems that put back 'in' not just take out. NO COAL, NO NUCLEAR, no more hydro, no more diesel.
38	Good to have as a backup power source
40	Emergency back-up power by diesel should be maintained, but some communities run diesel all the time. These should be priorities.
41	Let's get off fossil fuels. It is hypocritical to refuse to develop oil and gas in our own backyard while we use much much more than other parts of the world who suffer from the development that our use requires.
43	The future of energy in the Yukon or Yukon Energy's future? Very confusing questions.

	Congrats to whomever worded it-you're good! Yes we want enough environmentally responsible and affordable energy to meet our needs, but it should be developed in a fiscally responsible way as well.
44	I'd like to see more alternative choices, but realise that's easier said than done - expense, challenges to connect to the grid, technology issues etc.
45	Please allow home owners to produce electricity, and to be able to sell it back to the grid.
46	Bio fuel/Co-generation
47	Hopefully you'll stay Yukon owned and push for more alternative energy.
48	use your resources wisely and keep the Yukon a viable living space
49	Quit with the elaborate plans, and rate hikes! Affordable Power with out spending capitol because you can to get your 10% on investment!
50	Work with Yukoners to promote energy efficient programs and environmentally friendly alternative energy. This also will protect and promote our beautiful territory.
51	Go nuclear!
52	develop a better maintenance program in repair/replace outdated lines and equipment
53	all I'm saying.. if its not broken? why fix it?
54	Get rid of diesel!
55	I think there is a lot more to be done with alternative energy sources. The windmills could be hooked up to something viable, e.g. greenhouses, so people can actually see the opportunities alternative sources can provide. The use of geo-thermal in heating homes is another area that should be looked into more, and used.
56	I would like to see the legislation move forward allowing private power producers to sell their wind/hydro generated power to the grid.
57	they should have both as one can be a backup
58	DO NOT OUTSOURCE!!
59	More exploration into geothermal would be nice to see, even establish a pilot project like the Heckel Hill windmills
60	IPP must become a reality in Yukon.
61	The goal should not be a combined effort, but a process of switching completely to greener sources.
62	Yukon has already created scales of economy based upon hydro electricity... the ecological footprint is less in continuing to develop hydro electricity then it is in developing alternative energy sources. Alternative energy sources are not all that they are perceived to be. We may need to be reliant on diesel generation for back up systems and that is understandable...
63	Yes. Set the conditions for success. Meaning do what is right and move into the alternative energy sources. to continue to use diesel is just wrong and creating impoundments is not the answer either. I accept a balance but more wind and geo thermal would be better. It may cost a lot up front but the payoff down the road is worth it.
64	I've heard there's a radar-detection method of stopping windpower ...er, fans...to prevent bird deaths.
66	I think it's important to keep Yukoners informed as to what the future plans are and what we need to do to help (as the general public)....Provide schools and teachers with more hands-on materials to educate our young people.... Help us to help ourselves!!!! :)
67	bio-diesel
68	You have collapsed two very different sources (wind and geo-thermal) into one. I'm not in favour of any more wind-related investments. Geo-thermal is worthy of investigation. The key thing is to build more supply. The price per kW I paid for electricity in the lower mainland is a fraction of the cost I pay here. We need affordable, reliable energy as a key ingredient in our economic future. Yes, NWT & NU pay more, but look at the precarious state of their economies; more private development, especially in mining and industry, will only happen with reliable, affordable energy.
69	So far Yukon Energy has been reliable and cost-effective provider of electrical energy and consumers would like to see the same high level of customer service from this company. The company definitely needs to add alternate sources of energy like wind and geo as Yukoners believe in environment friendly solutions are the best key to some key challenges of future.
70	Even investigating bio-diesel would be a step in the right direction.

71	Diesel is the most reliable power.
72	At least in the short term, demand shaping (cheaper off peak power) should be considered. And WHY is it not common knowledge when the generating capacity is at the edge? People could schedule discretionary power use to help everyone if that information was available.
73	until some other source of power can be developed
74	We need to use the environment in a healthy way to provide us with the energy generation we require now and in the future. Along with that all Yukoners need to learn to conserve energy in their homes and businesses. Yukon Energy needs to ensure it can provide enough power for us to grow in industry and private homes. This may mean research into alternative energy sources.
75	(Don't) sell Yukon's interests down the road. I dont trust them (gov't)
76	More consistency & less power bumps would be easier to live with, or some protection device at the meter?
77	We need to get the 'politics out of the picture, we need the diesels as back-up power in case of outages
78	Yukon Energy needs to diversify their energy sources by developing wind farms, near Whitehorse.
79	YE is awesome! Have spoken to people in the company - very nice and helpful
80	Have a positive belief in an energy conscience population to do the right thing.
81	just want to make sure we keep warm in the winter !
82	More windmills, More geothermal, - more renewable, reusable, and clean energy. It will better many things.
83	It is more important to control demand than supply. It is almost as important that we have a widely distributed system of micro producers- all customers should be producers and Yukon Energy could be relegated to a producer of last resort and a coordinator of power production. Only thus will our energy security be assured
85	i hope to see more encouragement on people having their own power generation at home and it being able to feed back into the grid.
86	question 4 is double barreled. i want yukon to DEVELOP alternative energy sources on its own for its own accord, NOT in combination with new hydro. i have lots more to say about yukon's energy future. call me (name and phone number removed for confidentiality)
87	Yes, why is question 4 a loaded question? What if I support wind/geo-thermal, yet don't want to see new hydro developed?
88	Energy includes more than just power. We need to also be thinking about heat and transportation as well. Changes to these sectors may put more demand back on to the power sector if it is clean power.
89	For obvious economic reasons today and into our future, we must put our energy plans in place now. This kind of plan attracts investment in our communities and in our people. The longer delayed, the longer we remain a "have not" part of Canada.

Prepared for the Yukon Energy Corporation
by Andrew Hume and Associates Ltd.
in association with Aasman Brand Communications

July 21, 2010

SUMMARY REPORT

Knowledge, Awareness and Opinion Research

- Public Telephone and Online Survey Results
- Community and Business Leaders Survey Results

July 2011

YUKON ENERGY

Prepared by Aasman Brand Communications and Andrew Hume and Associates Ltd.

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SECTION I
(Public Research)

Introduction

Telephone and online surveys were conducted throughout Yukon communities in January and February 2011 as part of a Phase II research initiative. The overarching intent of this research is to provide the Yukon Energy Corporation with reliable information relative to the knowledge, awareness and views of Yukon residents toward the corporation and current and future energy needs.

The research was also designed to identify the knowledge of Yukoners concerning energy issues and strategic alternatives and actions of Yukon Energy toward achieving a clean, reliable and economically viable energy future.

Several of the survey questions paralleled questions asked in telephone and online surveys conducted in Phase I research (May-June 2010) to identify changes in knowledge, awareness and view of Yukoners concerning energy related issues.

Research Goals:

1. To provide Yukon Energy with reliable information relative to the knowledge, awareness and views of Yukon residents toward the corporation and current and future energy needs.
2. To identify knowledge levels of Yukoners concerning Yukon energy issues and strategic alternatives and actions of Yukon Energy toward a clean, reliable and economically viable energy future.

Research Objectives:

1. To identify changes in knowledge and awareness around key energy needs, issues and experiences.
2. To identify awareness of various information campaign components initiated between Nov. 2010 and Jan. 2011.
3. To identify recall of core messages provided through campaign materials.

Research Methods

A combination of telephone and online surveys and pulse polls were conducted with the Yukon public in communities throughout the Yukon in February-March 2011.

The survey methods covered a range of questions on energy related issues affecting Yukoners.

This report focuses on the results of an online survey and a telephone survey undertaken in early 2011 and compares some (benchmark) responses from telephone and online surveys undertaken in Phase I (May-June 2010).

The online survey was promoted through a communications campaign using traditional and online media and information delivered to Yukon households. An incentive was offered to enhance survey participation.

The telephone survey used a randomized process in selecting individuals in several Yukon communities.

A series of pulse polls were also used. Pulse polls were published in the online edition of the Yukon News and on the Yukon Energy website. This method was designed to gather quick snapshot, top-of-mind responses to a few key issues and formed part of Yukon Energy's public communications initiatives. Pulse polls were also used to promote the online survey. While pulse poll responses are reported, they do not form part of the formal research analysis in assessing current knowledge and awareness.

To achieve an overall confidence level of 95% Yukon Energy wanted to hear from 380 respondents. In total 563 Yukoners responded to the telephone (174) and online (389) surveys. The series of pulse polls received a total of 849 responses.

Respondents by Community

Online Survey
The online survey captured 389 respondents. Eleven Yukon communities participated. Some respondents did not indicate their community of residence. Identified response communities included:

Whitehorse:	303	Carcross:	3	Old Crow:	1
Dawson City:	19	Dest. Bay:	3	Stewart X:	1
Marsh Lk:	14	Mt. Lorne:	3	Rock Cr:	1
Watson Lk:	8	Teslin:	2	Mayo Rd.	1
Mayo:	7	Burwash Ld:	2	Golden Horn:	1
Tagish:	6	Carmacks:	2	Alaska Hwy:	1
Haines Jct:	5	Faro:	2	Unknown:	4

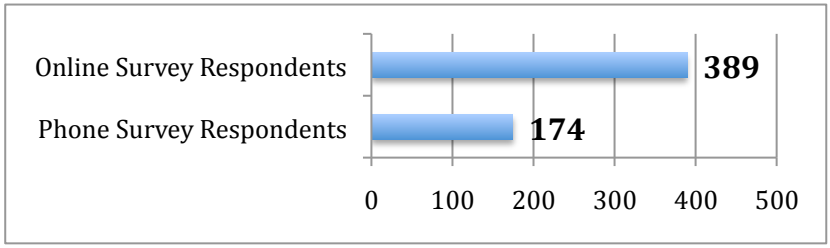
Telephone Survey
The public telephone survey included a randomized sample of 174 Yukon residents from seven communities. Response communities included:

Whitehorse	97
Marsh Lake	27
Dawson City	19
Haines Jct.	10
Carmacks	10
Teslin	10
Ross River	1

Summary of Key Findings

Engagement and Interest in Energy Issues

The overall response rate to the online survey and pulse polls and the willingness to participate in a telephone interview (with a very low decline rate) indicates Yukoners are significantly engaged and interested in energy related issues.



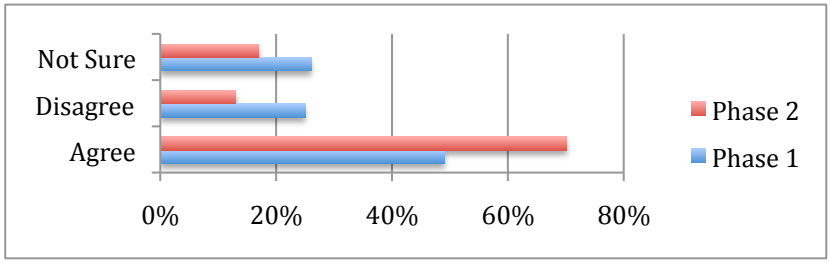
Knowledge/Awareness

Yukoners have a good understanding of energy issues and are aware that strategies are needed to increase production to meet future demands – particularly those of industry that is seen as the big energy consumer.

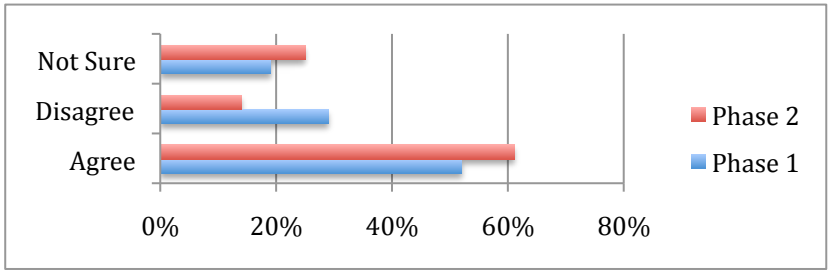
There was an increase in the level of knowledge and awareness around energy issues over the eight-month period between Phase I and Phase II research.

Most Yukoners agreed that power production in the Yukon needs to increase to meet projected future demands and a majority were able to identify some awareness related to a number of Yukon Energy production or system enhancement initiatives.

Do you agreed or disagree with the view that at the current rate of growth Yukon will not have enough energy to meet future needs?

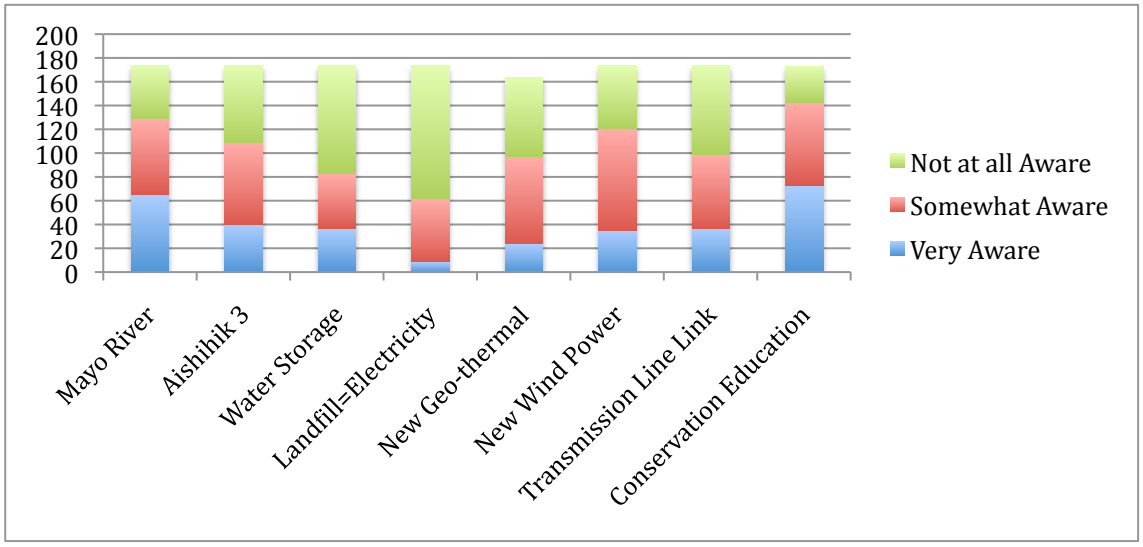


Online Survey



Telephone Survey

Telephone Survey: How aware are you of the following energy development initiatives?



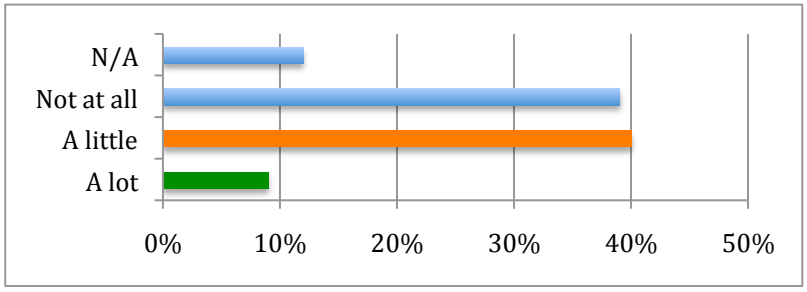
Online survey responses to this question showed a higher level of awareness related to the Mayo River project and to conservation and education initiatives. Low awareness related to the conversion of landfill waste to electricity was evident in both online and telephone survey methods.

Views and Perspectives

Respondents who *have not* changed their views between Phase I and Phase II research periods (39%) indicated it was because they had no new information, or not enough information to influence a change in views. Those who *have* changed their views a little or a lot (49%) said it was because of exposure and access to new information or increased information availability.

Results were consistent between both survey methods.

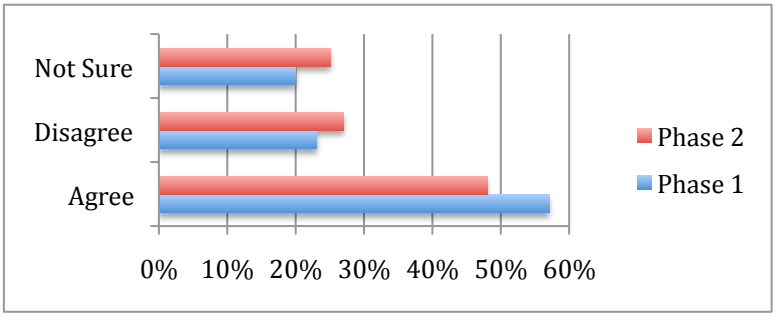
Telephone Survey: Have your views (on energy related issues) changed in the past six months?



Public Confidence

Between Phase I and Phase II, public confidence has declined (from 57% to 48%) on the question of Yukon Energy's ability to *'effectively plan and develop clean energy sources to meet future needs'*.

Telephone and Online Surveys (Phases I and II) combined and averaged response: Do you agree or disagree with the following statement: Yukon Energy has the ability to effectively plan and develop clean energy sources to meet future needs.

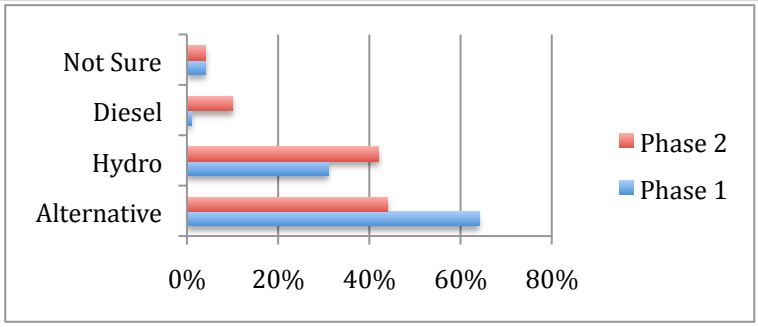


Note: 'Clean energy' was not defined and the reasons or factors affecting the public's views related to confidence were not explored in this research.

Preference for Alternative Energy and Conservation

There is a strong view among Yukoners that alternative energy is important from both an environmental perspective and to diversify capacity to meet future demands. Many feel Yukon could be a leader in alternative energy development and that greater conservation measures need to be taken. At the same time, there is an increasing view that alternatively produced energy may need to be supplemented with hydro generated energy.

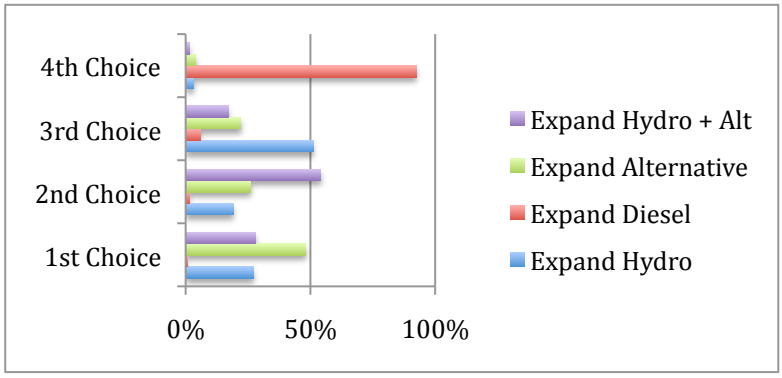
Telephone Survey: If you could choose where your energy comes from what would be your preferred source?



With telephone survey respondents there has been a leveling of support between alternative and hydro as a preferred choice for power generation when comparing the Phase I and Phase II surveys. Phase I survey respondents clearly favor alternative energy over hydro while the Phase II responses show a much closer balance between alternative and hydro. This may be attributed to increasing awareness of the overall future capacity that will be needed relative to the ability to meet this capacity through alternative energy alone.

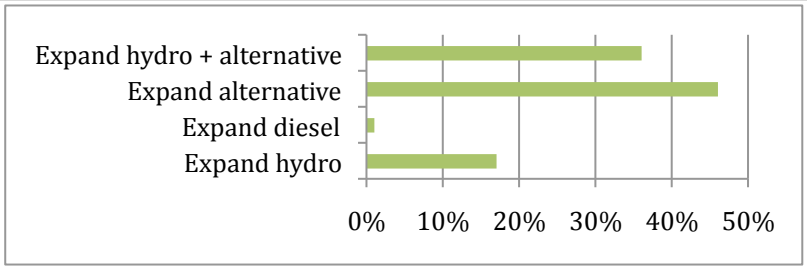
The Phase II online survey, using a ranking option, shows strong support for expanding alternative energy and for a combined alternative/hydro approach.

Online Survey: Indicate your choice preferences regarding expanding energy sources.



In addition to the telephone and online surveys a series of 'pulse polls' were published in the online edition of the Yukon News and on the Yukon Energy website allowing readers to cast a ballot on a specific question. The pulse poll on preferred energy sources reinforced the publics' views on developing alternative energy sources (as well as pursuing a combined hydro/alternative approach).

Pulse Poll: What is your #1 preference for future energy production? (362 votes)

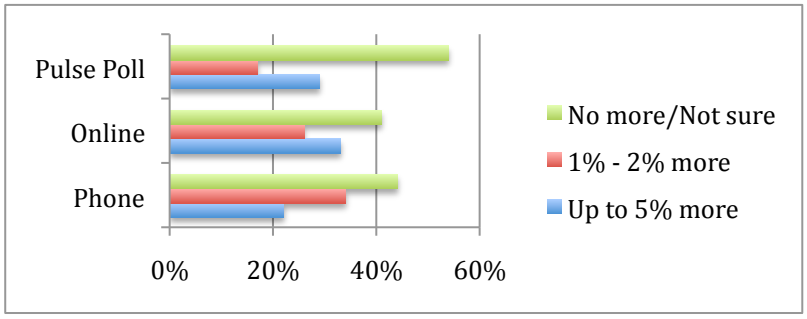


Willingness to Pay for Alternative Sourced Energy

While there were differences in responses between the telephone and online surveys on the question of the willingness to pay more for electricity if it is generated from an alternate source such as wind or geo-thermal, the majority of Yukoners said they would pay more for alternatively produced energy.

With the pulse poll question, a majority said they would not be willing to pay any more than what they are paying now.

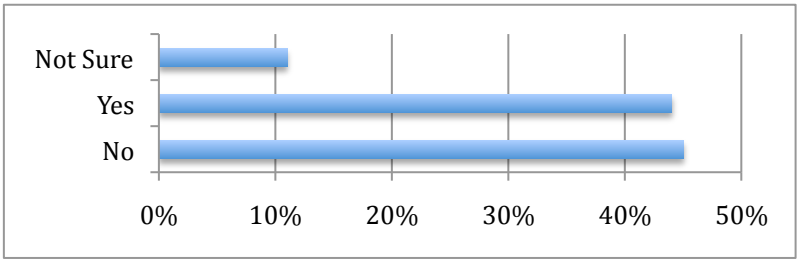
Telephone/Online/Pulse Poll results: Willingness to pay more for alternatively sourced energy.



Communications and Awareness

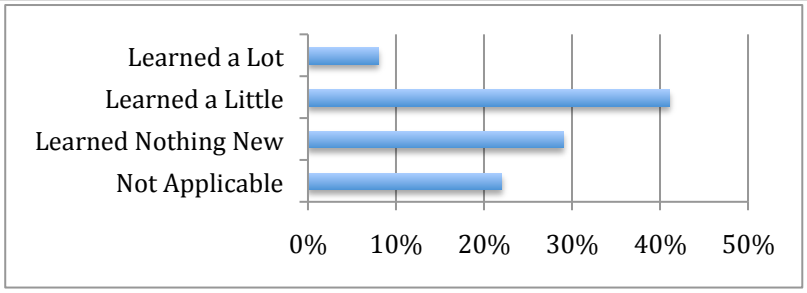
Recent communications initiatives undertaken by Yukon Energy show that an equal number of those surveyed recalled seeing communications material (advertising or household mailer) as those who did not recall seeing information sponsored by Yukon Energy.

Combined and Averaged Telephone/Online Surveys: Do you recall seeing sponsored advertising or a household mailer from Yukon Energy on energy issues?



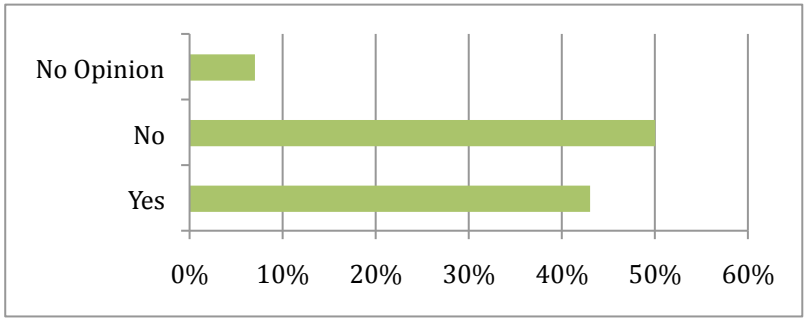
When Yukoners were asked if their knowledge and awareness have increased over the past six months, half (49%) said they have learned a little or a lot.

Combined Results from Telephone and Online Surveys: In the past six months, have you learned a little, a lot or nothing new about Yukon energy issues?



(Note: The knowledge question was asked in the context of Yukon Energy's communications initiatives. The Not Applicable response refers to those who said they couldn't recall seeing information materials provided by Yukon Energy or who declined to answer the question)

Pulse Poll result: Do you know more about Yukon's power issues today than 6 months ago? (166 votes)



Both the telephone and online survey methods provided an opportunity for respondents to provide additional comments related to key issues.

Desire for Change

- From online survey respondents, there were about twice as many comments that reflect a general opposition to the way things are today with respect to energy supply, demand and production issues (particularly the use of diesel for power generation).

- Comments supporting change focused on a concern that current planning is not going to meet future demand. Some discontent also stems from the frequency of power outages.

- Many expressed comments supporting hydro as the right way to go in meeting current and future needs. A noted previously, there is strong support for a combined alternative/hydro approach as well as continuing support for the development of new alternative energy sources and continued conservation and education efforts.

Consumption and Future Demands

- Many respondents are unsupportive of industry's needs and the increasing demand that large industry places on energy consumption and the perceived impact this has on the cost of power to residential consumers.

- There is a perception industry is not paying fairly (i.e. paying below-cost for their power). There is also a perception that industry is a higher priority than Yukon residents. Some respondents said industry should be made entirely responsible for producing and paying for the energy it needs. There is a concern that as new industry and large-scale developments comes on-line, demands for power will increase significantly.

SECTION II
(Community and Business Leaders Research)

Introduction

Between April 20 and May 6, 2011, a total of 54 business and community leaders were invited to participate in a survey on energy issues in the Yukon. A total of 42 people (79%) responded to the survey invitation.

This data complements a similar survey of 41 community and business leaders conducted in July 7-15, 2010. For comparative analysis where the same question was asked in both research phases, the findings are shown as Phase I (July 2010) and Phase II (April/May 2011).

In addition to the core benchmark questions included in the Phase I survey, the Phase II survey included several supplementary questions related to a willingness to pay more for power generated from alternative energy sources and awareness of current Yukon Energy projects and programs.

Research Goals

- To provide the Yukon Energy with current knowledge, awareness and views among Yukon business and community leaders toward the corporation and current and future energy needs.
- To compare any changes in knowledge, awareness and views over the period from July 2010 to May 2011.

Research Objectives

- To establish baseline knowledge, awareness and views
- To assess change in knowledge, awareness and views over time
- To inform the design and development of communications initiatives targeted to community and business leaders regarding Yukon Energy's planning, priorities and actions

Research Methods

The survey was sent by email to community and business leaders in the communities of Whitehorse, Carcross, Burwash Landing, Haines Junction, Mayo and Carmacks. Ninety percent of respondents identified themselves as living/working in Whitehorse. The remaining 10% were from Haines Junction and Destruction Bay/Burwash Landing.

The majority (61%) of respondents to the Phase II survey self-identified as coming from the private sector, balanced by those from the public or community sector or an advocacy based organization.

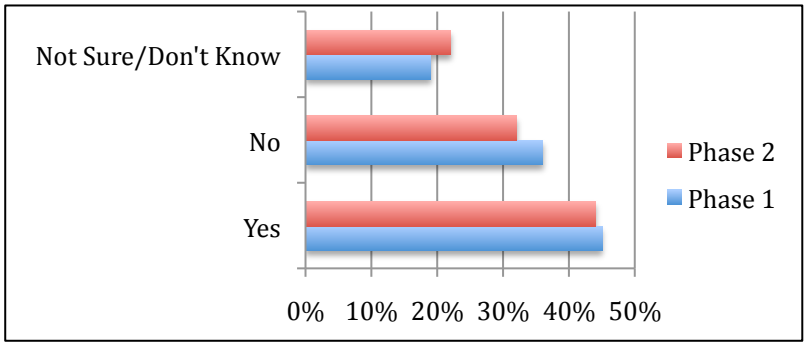
The survey included telephone interviews and an online survey with corresponding questions used in each method. For respondents who preferred to be interviewed on the telephone, their responses were captured in the same format as the online survey.

Confidence Indicators

The level of confidence among community and business leaders in Yukon Energy's ability to *'assess Yukon's future energy needs' increased* from 62% to 85% over the past 10 months.

Over the same time, the level of confidence in the corporation's ability to *'plan and develop clean energy sources to meet future demands'* remains unchanged at approximately 45%. Just over 20% remain unsure of their level of confidence on this question.

Do you have confidence in Yukon Energy to plan and develop clean energy sources to meet future demands?

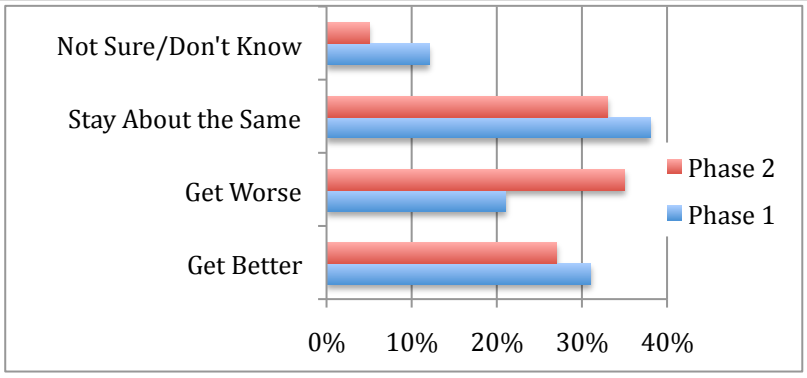


Past Experience and Confidence in Future Reliability of Power Supply

The survey asked respondents to think retrospectively over the past 12 months in terms of their past experience with energy supply issues as well as consider their relative confidence in the future reliability in the supply of power over the next five years.

Business and community leaders expect the availability of power supplies to get worse over the next five years. This shows a negative shift in confidence related to future reliability from 21% of Phase I survey respondents saying reliability will get worse, to 35% of Phase II respondents expecting supply reliability to worsen.

Expected reliability in the power supply over the next 5 years:



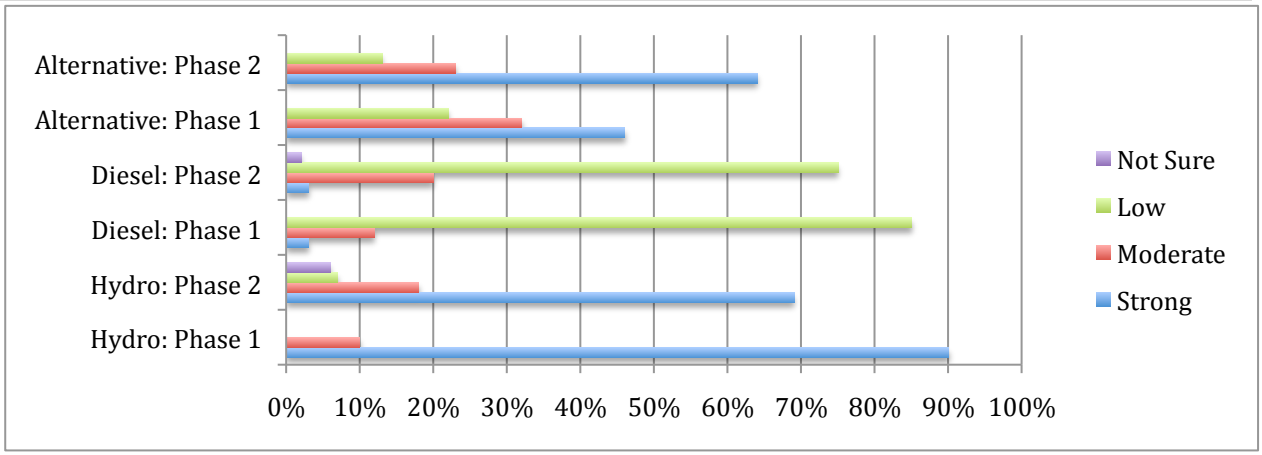
Support for Alternative Sourced Energy

Responses over the two research periods show a decline in strong support for hydro and increased support for alternative sources. Support for the continued development of alternative energy sources in combination with new hydro sources was identified by just over three-quarters (77%) of respondents as a first or second choice preferred option for meeting future energy needs in a Phase II optional question.

(Note: The 'Hydro + Alternative' response is not shown in the chart below as the question was asked as an additional option in Phase II research).

A very low level of support for diesel-sourced power remained consistent between both research periods. There was an increase in the level of 'moderate' support for diesel in Phase II responses. This may be related to those who expect supply reliability to worsen over the next five years and see a continued need for back-up diesel generated power until overall capacity from other sources is increased.

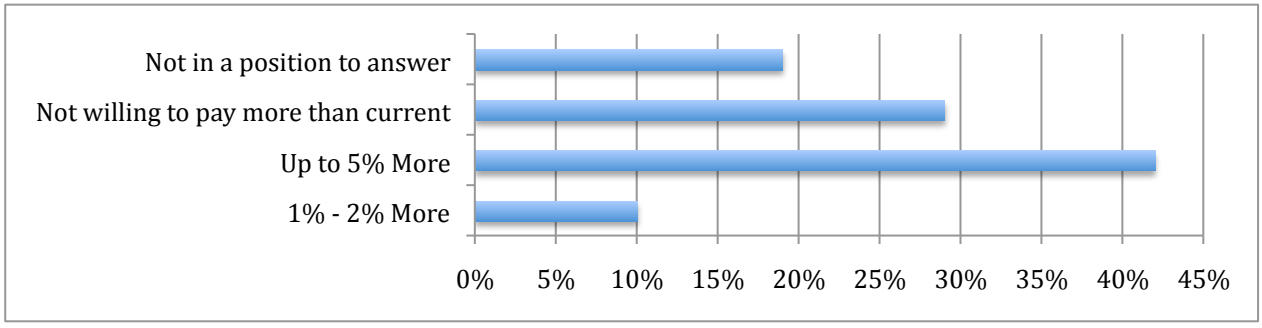
What level of support do you give each of the following power generation options?



Willingness to Pay More for Alternative Sourced Energy

Just over half of respondents (52%) said they would be willing to pay more for electricity produced from alternative sources ranging from 10% who said they would pay 1%-2% more and 42% who indicated a willingness to pay up to 5% more. This indicates support for the continued development of alternative sourced energy as well as an understanding that these technologies will cost more to design, develop and bring on-line.

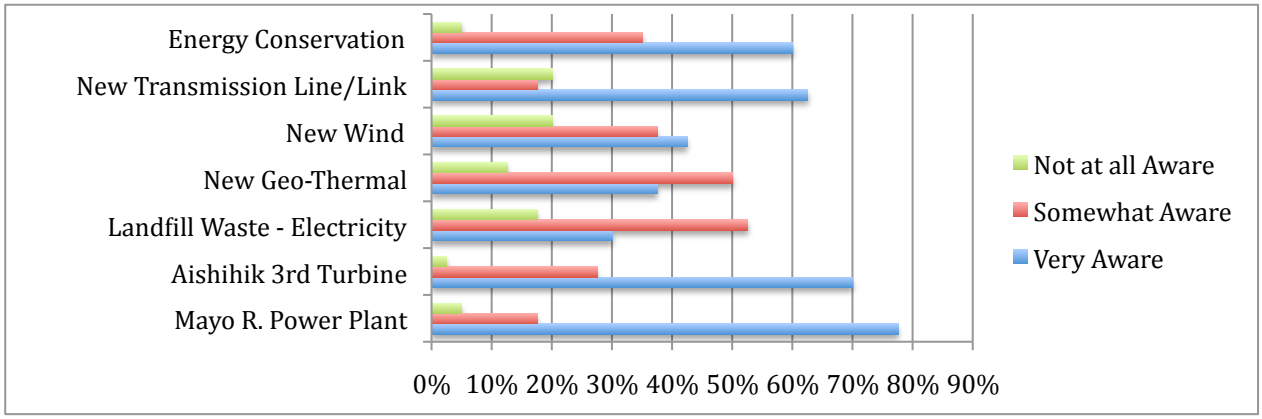
Thinking about your company or organization, are you willing to pay more for electricity if it is generated from an alternative source such as wind or geo-thermal?



Awareness of Yukon Energy Projects

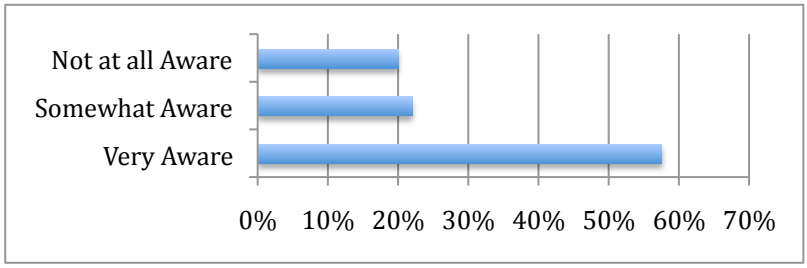
The Mayo River power plant and third turbine at Aishihik show a high awareness followed closely by the new transmission line link and energy conservation measures. Wind-based energy shows a reasonably strong awareness with 42% indicating high awareness and 38% somewhat aware. Geo-thermal energy sources and converting landfill waste to electricity show the lowest awareness levels.

How aware are you of the following Yukon Energy projects?



A question related to water storage planning being undertaken by Yukon Energy shows that almost 60% are Very Aware and just over 20% Somewhat Aware of this initiative

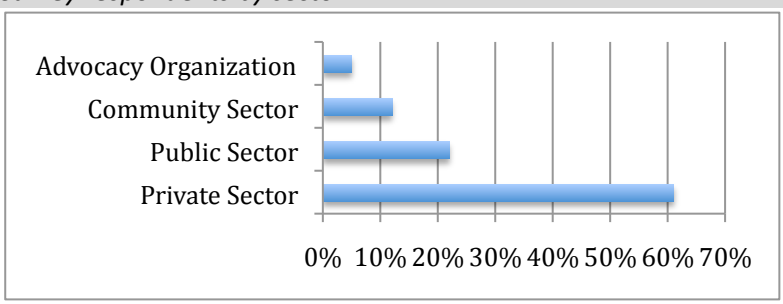
To help meet peak power demands in the winter when water levels are low, Yukon Energy is exploring ways to store more water in the Atlin, Marsh and Gladstone Lakes systems. How aware are you of Yukon Energy's research and planning for increased water storage?



Sector Response

A majority of respondents to the community and business leaders survey identified themselves as being associated with the private sector, followed by the public and community sectors. Several respondents identified association with an advocacy-based organization.

Survey respondents by sector:



Summary of Comments
About 80% of respondents for the survey took the time to write a comment outlining concerns, ideas and observations about Yukon Energy and related energy issues and priorities. This type and level of response reflects a highly interested target group.

A review of responses indicates the following key points of interest and concerns:

- **Education and Communication**
  The public, business, industry and interest groups need to know more about what is needed to meet current and future energy needs, what is being planned and when new energy sources will come on line.

- **Conservation and Incentives**
  There is a strong desire to enhance energy conservation efforts through education as well as by providing incentives for individuals and families, business and industry to participate in energy conservation efforts. The availability of funding help through small grants and loans to enable participation in energy conservation (such as energy retrofits etc.) was also noted. Both industry and political leaders are seen as being important in creating a climate for positive change.

- **Evidence-based Costing**
  Professional energy audits of buildings and operations resulting in clear options and quantifiable benefits derived through energy conservation was noted along with the need to use new technologies such as smart meters to be able to assess variable costs based on time-of-day usage.

  In keeping with the conservation and education theme, several respondents commented on the need to make people more aware of peak usage times of day and encourage more off-peak usage. Comments also reflected a need to design and provide incentives (such as rebates) for those who actively demonstrate conservation measures.

- **Alternative Sourced Energy**
  Consistent with overall survey responses, there continues to be an underlying theme of support for the development of alternative sourced energy as a way to supplement the overall supply of power.

Note: The length of residency of respondents to was consistent between Phase I and Phase II research with a strong majority being resident in the Yukon for over 20 years. The second highest group (at 10%) indicated they have been a Yukon resident for one-to-five years.

Yukon Energy Corporation

Public and Stakeholder Phone Survey Results
Public Awareness Campaign Phase 1:
Research Report 1

Prepared by
Andrew Hume and Associates Ltd.
In association with Aasman Brand Communications

June 25, 2010

aasman
branding on purpose

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Introduction

The research component of the public awareness campaign was developed to establish benchmark indicators among target audiences to assess and evaluate knowledge of Yukon Energy and awareness of energy related issues.

The research model was built in a knowledge, awareness, and behaviour (KAB) evaluation design. KAB essentially begins by testing current knowledge levels, assesses any change in awareness levels over time (ie: as a result of an educational or communications intervention) and finally whether any increase in knowledge and awareness or change in beliefs and expectations.

Two audience groups are targeted in this research:

1. Allies: Allies include businesses and associations, community organizations, First Nations, governments, and other groups who have a vested interest in supporting a long-term clean energy strategy for the territory. By understanding the vision and strategy of Yukon, this audience will be more inclined to envision a positive investment future in Yukon resulting in economically stronger communities.

   This audience also includes potential allies-Yukon politicians, the Yukon Conservation Society, the Utilities Consumer Group, the Yukon Utilities Board, and others.

2. Public Audience: This audience is comprised of all Yukoners who use or have an interest in electrical energy. Typically, this audience is predisposed to renewable sources of energy versus fossil fuel sources of energy for both cost and environmental reasons.

A **Public telephone survey** was conducted with 184 randomly selected respondents in six Yukon communities between June 2 – 8, 2010 involving a 10-15 minute interview covering a range of questions on the Yukon Energy Corporation and energy related issues.

The six communities selected for the public phone survey included: Whitehorse; Marsh Lake; Teslin; Carmacks; Haines Junction; and Dawson City.

An **Allies telephone survey** involving 25 business and community leaders and interest groups was conducted between June 4 – 11, 2010. The survey recipients were selected to provide a cross sample of individual businesses, Yukon-wide associations and local community leaders. Communities included: Whitehorse; Mayo; Faro; Watson Lake; Haines Junction.

Both phone surveys were conducted prior to the launch of the public awareness campaign.

In addition to the telephone surveys an **online public survey** is also being conducted over a 4-6 week period (June 15 – June 30, 2010). The online survey is being conducted in conjunction with the campaign with participation promoted through the campaign as well as on the Yukon Energy Corporation's website.

Research

Research Goals

- To provide the Yukon Energy Corporation with current Knowledge, Awareness and Behaviour (KAB) among Yukon residents and business and community leaders toward the corporation and current and future energy needs

- To build a renewed sense of trust and confidence among Yukon residents in the corporation supporting its vision of a clean energy future

Research Objectives

- To establish baseline KAB data
- To acquire research support to effectively position the Yukon Energy Corporation and its vision for a clean energy future
- To inform public communications initiatives undertaken by the Yukon Energy Corporation
- To test effectiveness of communications, information and messaging

Research Targets

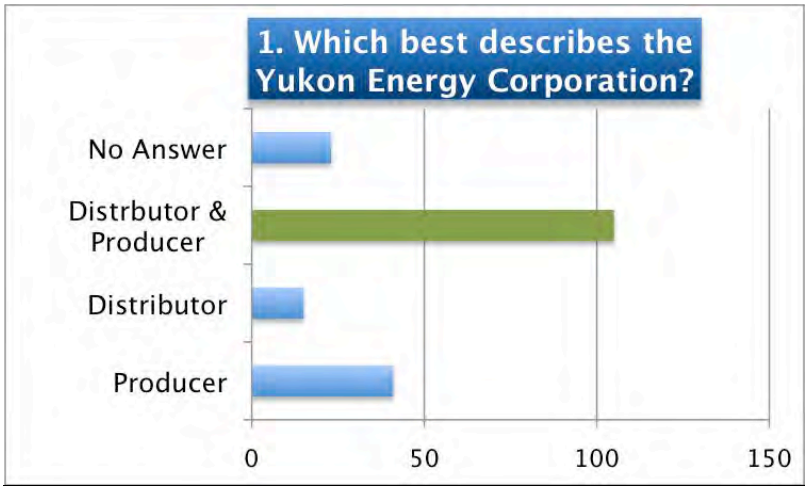
To achieve a confidence level of 95% an overall target for all methodologies is 380 respondents. The combined participation from both telephone surveys is 209 (public phone survey: 184; stakeholders phone survey: 25). The online survey will deliver the remaining responses.

Following are the findings of the public and stakeholders phone surveys.

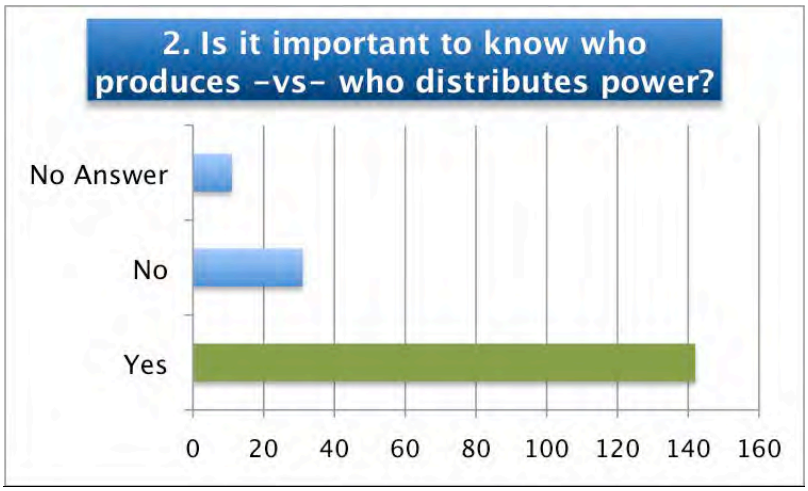
Public Telephone Survey Findings

The majority of Yukon residents are aware the Yukon Energy Corporation is both a producer and distributor of electrical power.

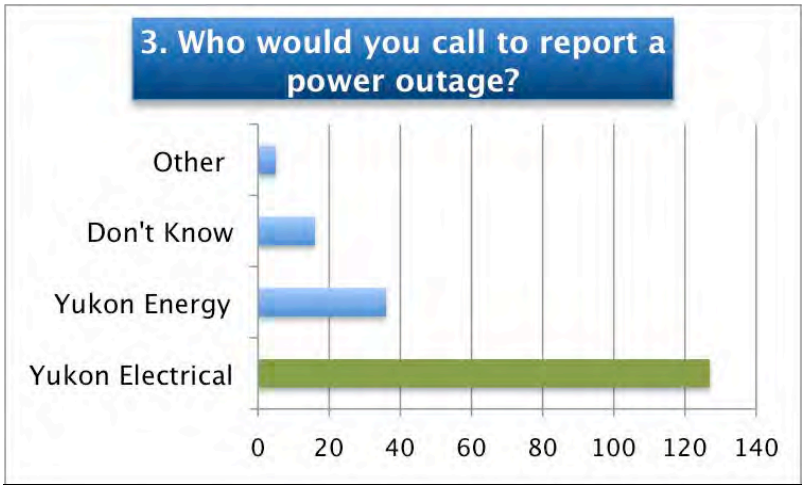
However a significant number are not aware of the dual responsibility of the corporation with regard to the production and distribution of electrical power as indicated by those who said the corporation was only a producer or only a distributor or did not know.



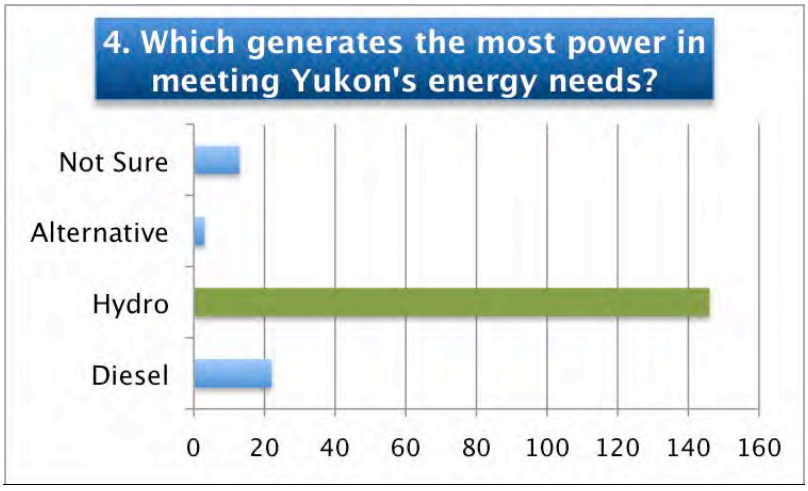
A strong majority of respondents said it is important for them to know who produces and who distributes power.



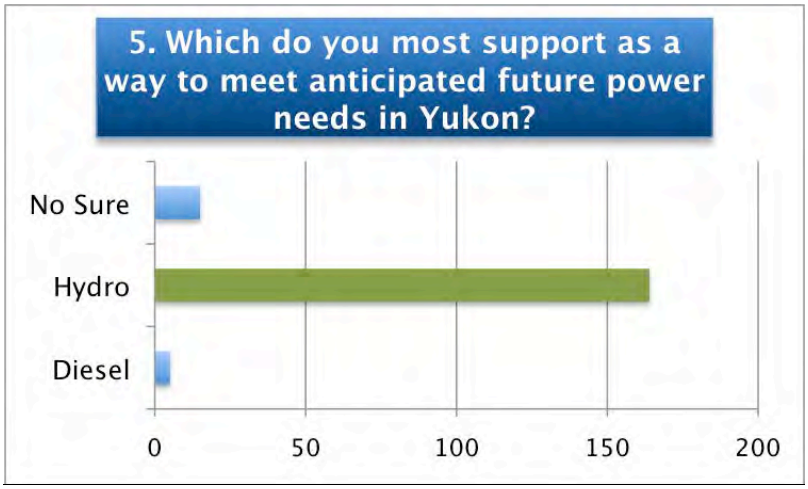
In terms of who residents would call if they experienced a power outage, a strong majority said they would call Yukon Electrical as the primary power provider. In looking at community variations on this question, responses ranged from a low of 25% (Dawson City) who said Yukon Electric would be their first point of contact to a high of 80% of residents (Carmacks and Haines Junction) who would call Yukon Electric first. Over three-quarters (76%) of Whitehorse residents identified Yukon Electric as a first contact point.



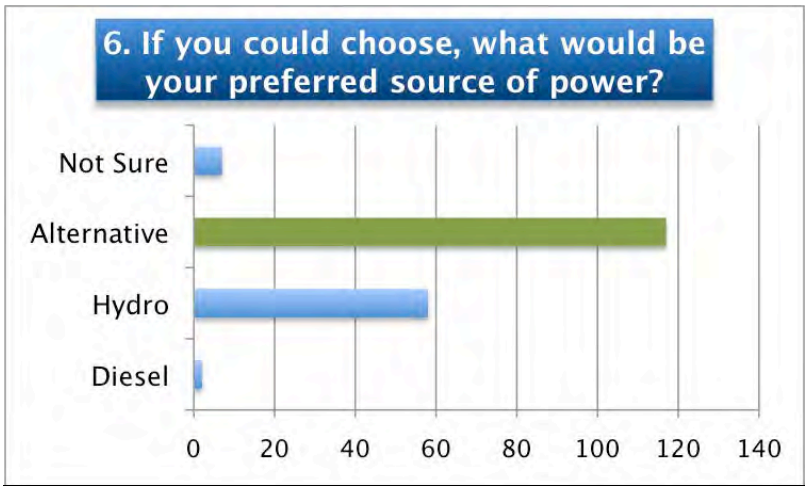
A strong majority of Yukon residents are aware that Yukon's power is primarily hydro generated. This is consistent across all communities surveyed.



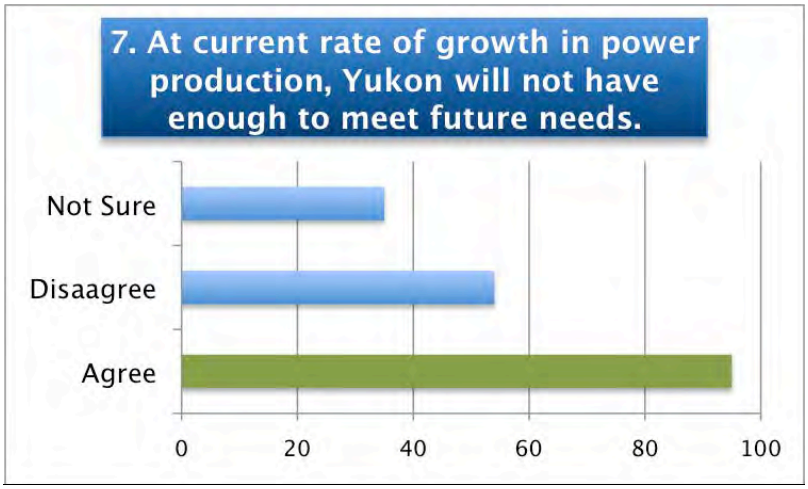
Hydro generated power is clearly a preferred alternative to diesel-generated power across all communities.



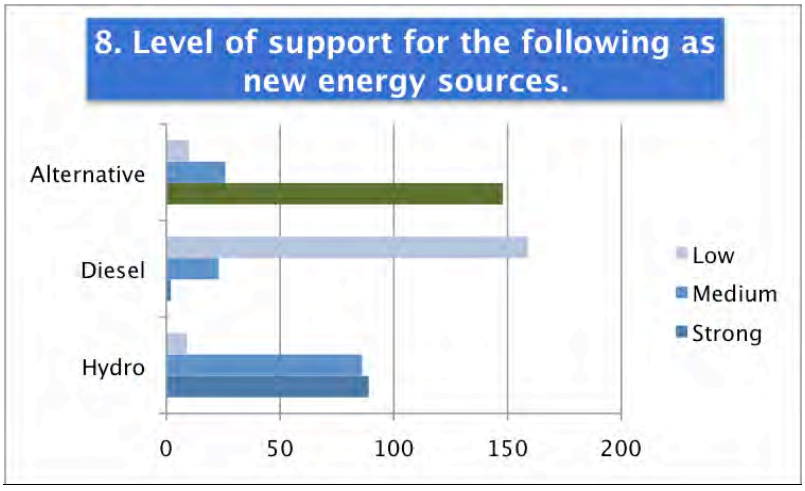
The phone survey identified a strong preference for the development of alternative energy sources. 'Alternative' was described as wind and geo-thermal. Carmacks showed the highest level of support for alternative sources at 70% and residents of Marsh Lake showed the lowest support at 56%. In Whitehorse 65% of respondents identified alternative as preferred source of power.



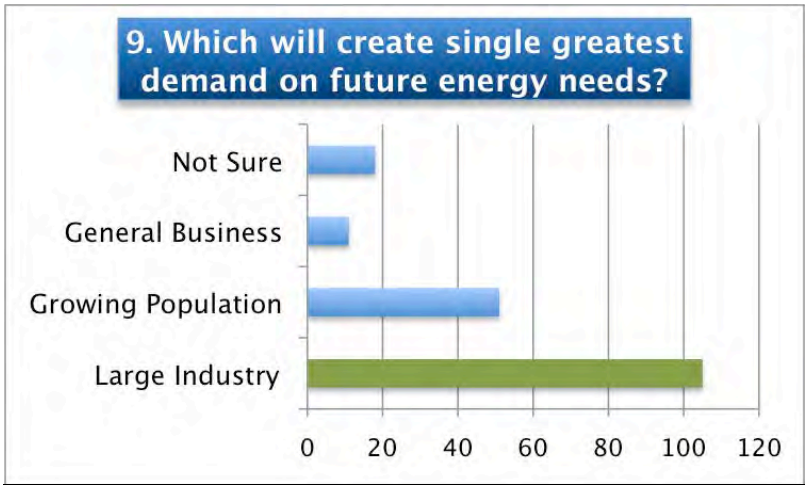
When asked to think about the energy production and future needs, only slightly more than half (52%) of residents agreed that Yukon will not have enough energy to meet future needs. This was relatively consistent across all communities with the exception of Carmacks where 80% of respondents agree with this projection.



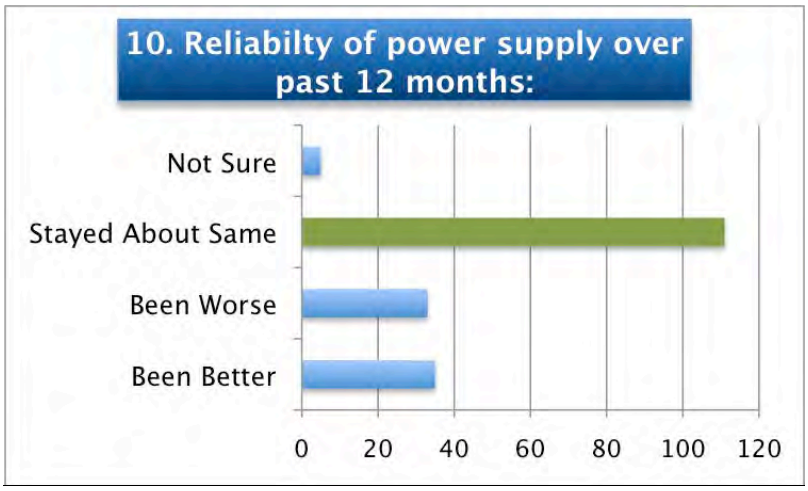
A clear majority of respondents do not support diesel-generated power as a future energy source. Consistent with question #6, the strongest support is indicated for the development of new alternative energy sources followed by hydro which received medium to strong support.



Yukon residents see large scale industry as the big driver in terms of creating the greatest demand for future energy needs followed by population growth (residential consumption). There was however a wide variance in response by different communities to this question ranging from a low of 50% (Dawson City) who see large industry as the biggest future power consumer, to 80% of respondents from Carmacks. In Whitehorse 52% of respondents said they saw large industry as creating the biggest energy demand.

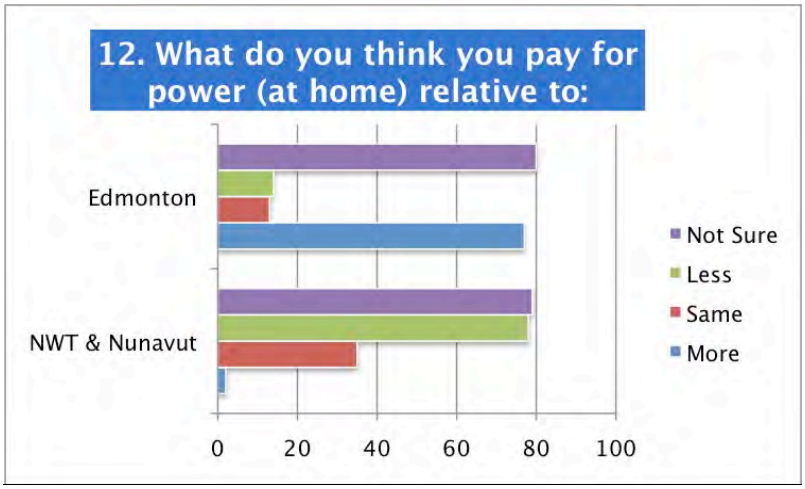


Questions #10 and #11 identified how reliable Yukon residents feel their energy supply has been over the past year and how reliable they think it will be over the next five years. The majority of respondents feel there has been little change in reliability over the past 12 months or that reliability has improved. Responses varied marginally by community with most in the 75%+ range in saying reliability has been better or the same.



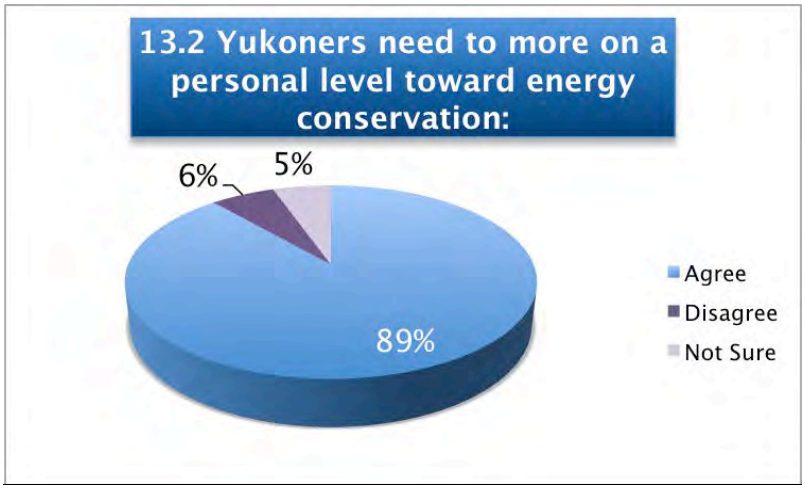
In the context of their recent experience (past 12 months) the majority of Yukon residents (78%) feel the reliability of power over the next five years is likely to remain unchanged or get better.

Using Nunavaut/NWT and Edmonton for comparison, survey respondents were asked to indicate if they felt they paid more, less or the same for power. While Yukon residents feel they pay less or are not sure in relation to other northern residents they clearly feel they pay more than residents of Edmonton. Forty-four per cent (44%) of respondents said they were not sure.

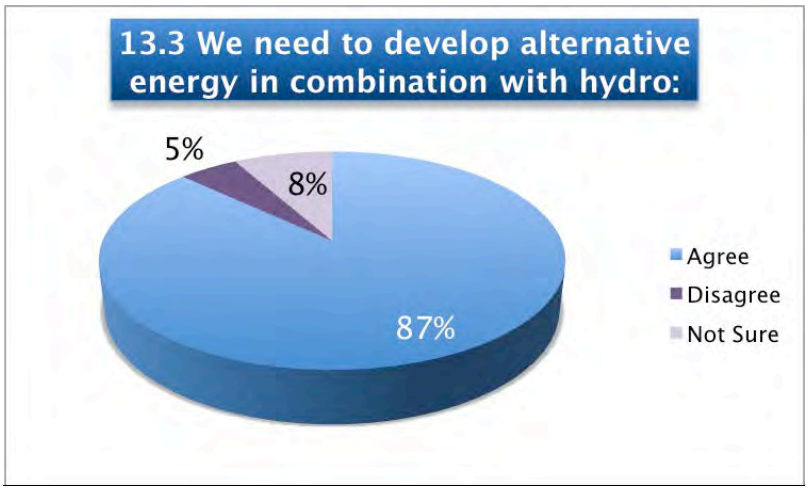


On the question of confidence in the Yukon Energy Corporation related to planning and developing clean energy sources to meet future needs, 58% said they had confidence in the corporation. The level of confidence ranged from a low of 30% in Haines Junction to a high of 80% in Carmacks. In Whitehorse 62% said they have confidence in the corporation.

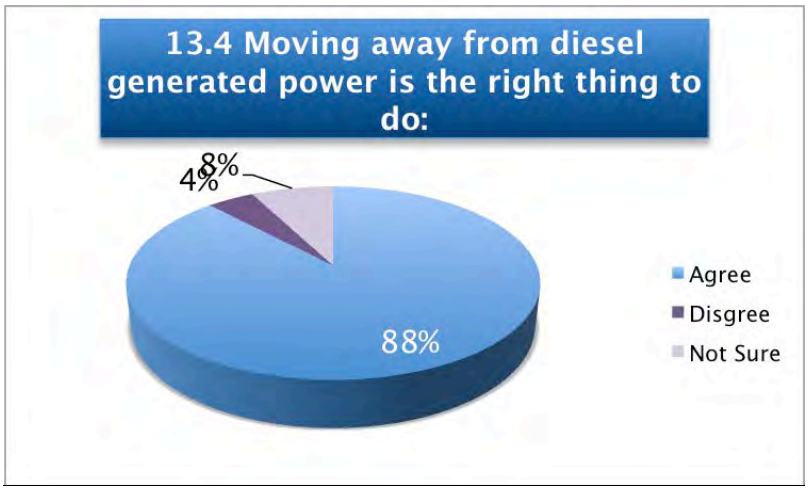
On the question of Yukoners assuming more personal responsibility toward energy conservation, 89% are in agreement.



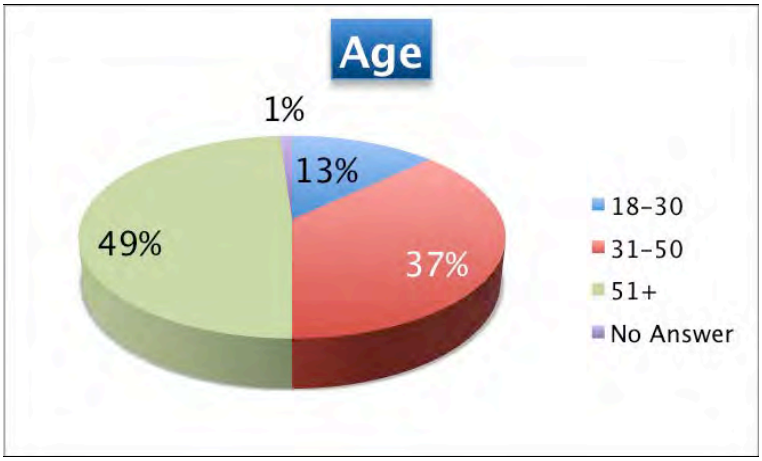
An equally high number (87%) of respondents agreed with a planning approach that would see new alternative energy sources developed in conjunction with hydro development to meet future needs.

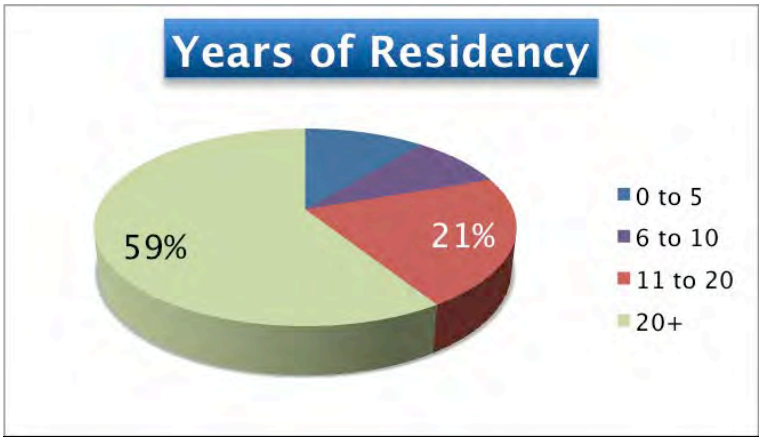


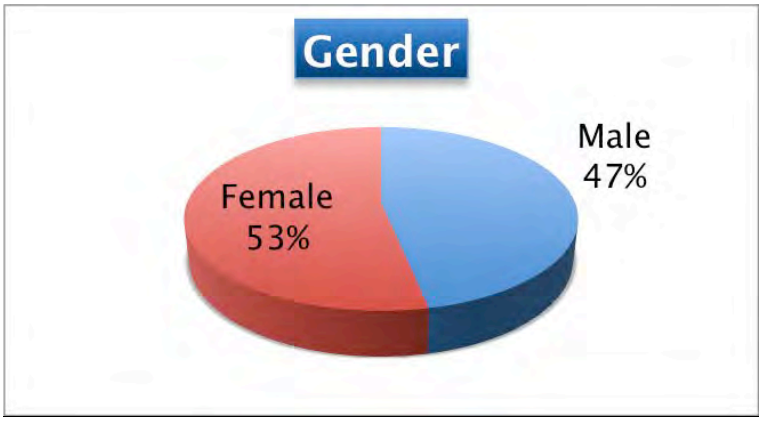
A strong majority (88%) reinforced their support for alternative and hydro by saying the Yukon needs to move away from diesel-generated power. Support for moving away from diesel-generated power ranged from a low of 70% in Haines Junction to a high of 90% in Whitehorse and Dawson City.



Almost half (49%) of respondents were 51 years or older with over a one-third (37%) in the 31 to 50 year age group. The majority of respondents were also longer-term residents with 59% indicating 20 or more years of residency. Gender of respondents was relatively evenly divided.

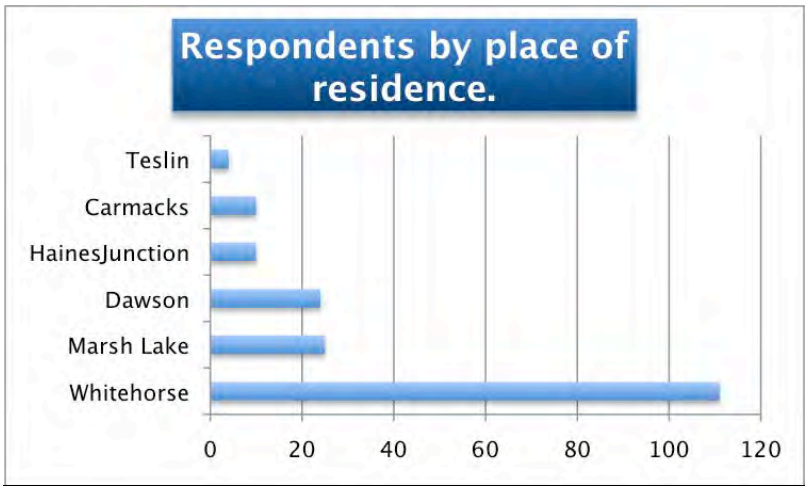






Sixty percent of respondents (111) were surveyed in Whitehorse with 25 residents in Marsh Lake and Dawson City participating in the survey. For the smaller communities of Haines Junction and Carmacks 10 phone surveys were done in each community. In Teslin four surveys were conducted.

> Note: It is important to note that the sample size in communities outside Whitehorse is not significant enough from which any conclusions can be drawn with any degree of confidence at an individual community level. The data was provided on a community-basis for some questions as a point of interest only.



Findings from the stakeholder telephone survey can be found the following section.

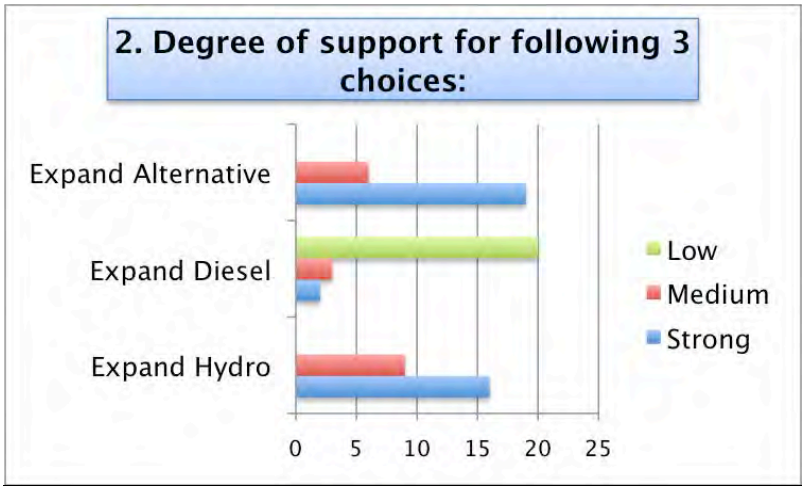
BUSINESS AND COMMUNITY LEADERS (ALLIES) PHONE SURVEY FINDINGS

Introduction

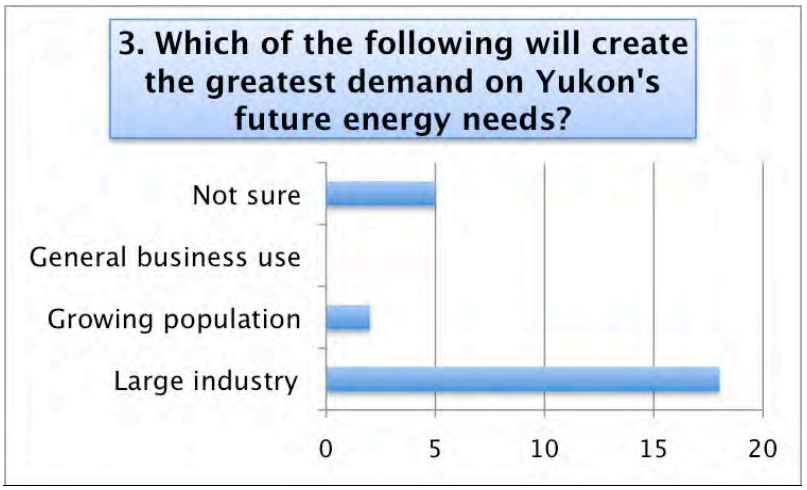
A telephone survey involved 25 business and community leaders representing a cross sample of businesses, Yukon-wide associations and local community leaders.

Yukon business and community leaders indicate a high degree of confidence (88%) in the Yukon Energy Corporations' assessment that new energy sources will be needed within the next five years in order to meet future demands.

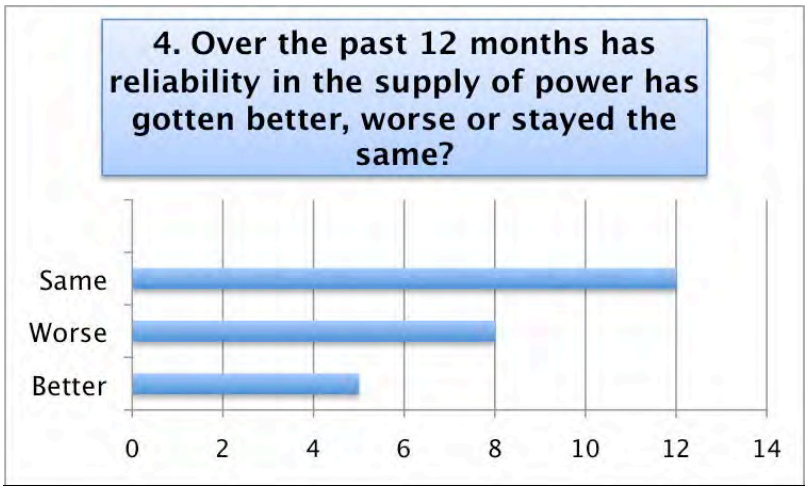
Business and community leaders indicate a strong preference for alternative energy followed by hydro development. Support for diesel-generated power is very low.



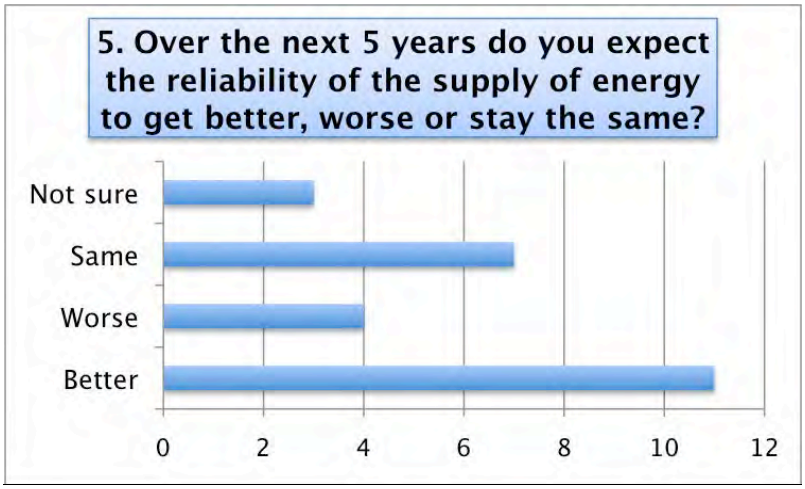
Consistent with the public phone survey, business and community leaders believe large industry will be a primary driver in future energy demands.



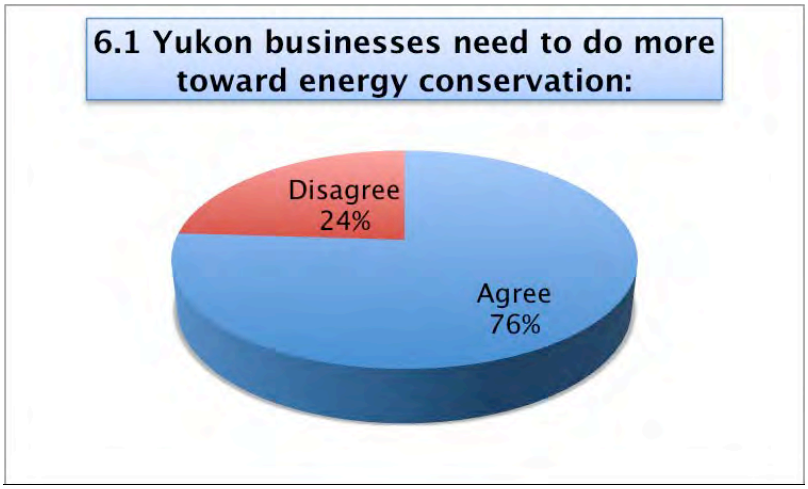
Approximately one-third of business and community leaders feel energy reliability worsened over the past 12 months as compared to about 18% of public survey respondents.



In terms of expected reliability over the next five years, business and community leaders feel more confident with almost half expecting reliability to improve and only 16% expecting reliability to get worse and over one-quarter (28%) expecting no change.

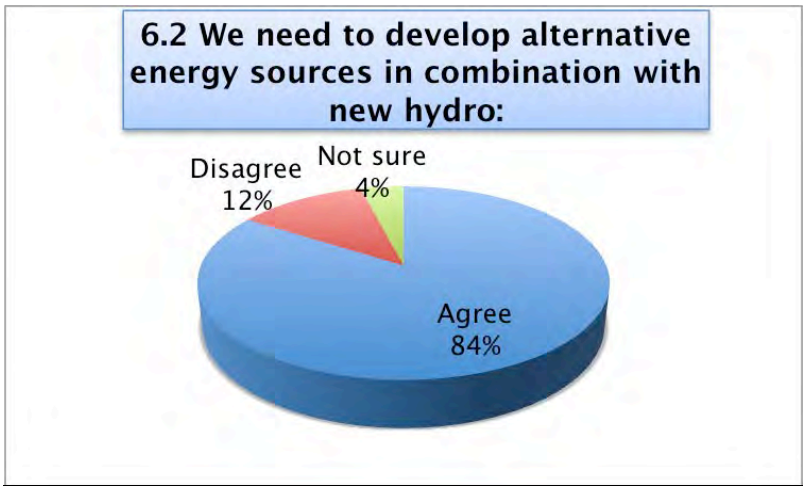


Over three-quarters (76%) of business and community leaders feel Yukon businesses need to do more toward energy conservation. While this is a strong indicator that businesses feel the need to assume greater responsibility for conservation, the public's sense of personal responsibility is much higher at 89%.

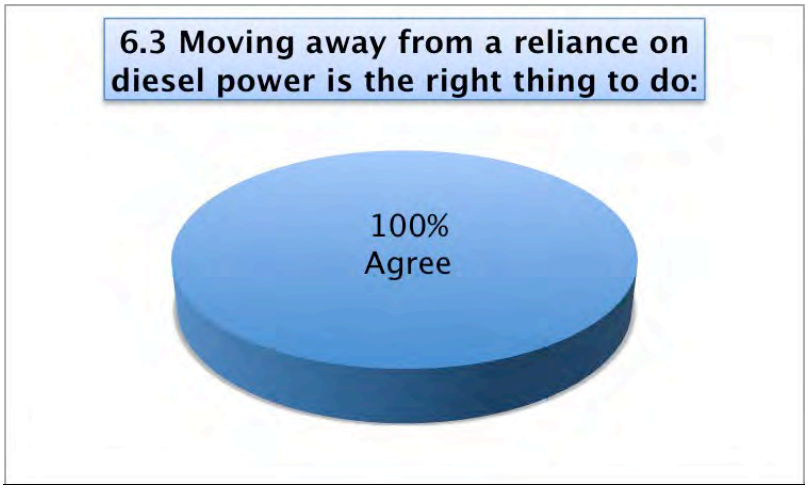


Comments related to this question indicate that conservations is a 'shared responsibility' across all sectors.

There is a high degree of support (84%) among business and community leaders for the development of alternative energy sources in combination with hydro. Alternative energy also received strong support from the general public.



Also consistent with the public's view, business and community leaders strongly believe that moving away from a reliance on diesel-generated power is the right goal for the Yukon Energy Corporation to be pursuing.



Additional comments suggested that multiple alternative sources need to be further explored including things like bio-fuels and waste-energy in addition to hydro, wind and geo-thermal and natural gas should also considered. Some suggest the corporation lacks creativity with respect to new clean energy sources and opportunities.

While a strong majority (84%) believe the Yukon Energy Corporation should be developing clean energy sources (see Q. 6.2), just over half (56%) of business and community leaders have confidence in the corporation's ability to effectively plan and develop clean energy.

Additional comments included:

- Political influence and interference with the Yukon energy sector affects productivity and the ability to plan effectively. (Several mentions)
- Responding to external opposition and special interest groups interferes with effective planning.
- Years of opportunity to develop new clean energy sources have yielded little results.
- Reliability and cost need to be considered when developing alternative energy sources.
- Investment needs to be made in Yukon's power distribution system.
- Open up power generation to enable third parties to be become involved.
- The corporation needs to do more public consultation (this survey was a good start).
- Lack of a strategic plan and cost-benefit analysis.
- Lack of talk related to encouraging energy conservation.
- Important to plan and develop now to meet future needs and not get caught energy short. (Yukon Energy Corporation appears to be doing a good job projecting what future needs will be).
- More communication is needed on energy issues and options.

General Service

Lighting Redesign and Equipment Incentive – *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 31-33/)*

Exhibit 1: Participation Projections – Lighting Redesign and Custom Lighting Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM91	Lighting Redesign Study	9,181 ft2	50,876 ft2	83,390 ft2	83,390 ft2	41,695 ft2	268,531 ft2
ECM80	Typical Lighting Project in	0 ft2	11,738 ft2	31,786 ft2	36,327 ft2	36,327 ft2	116,179 ft2
ECM81	Typical Lighting Project in Existing Bldg - Food Retail	0 ft2	2,702 ft2	7,139 ft2	8,159 ft2	8,159 ft2	26,160 ft2
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail	0 ft2	15,116 ft2	39,707 ft2	45,379 ft2	45,379 ft2	145,581 ft2
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel	0 ft2	14,437 ft2	33,687 ft2	38,499 ft2	38,499 ft2	125,122 ft2
ECM86	Typical Lighting Project in Existing Bldg - Restaurant	0 ft2	3,982 ft2	9,291 ft2	10,618 ft2	10,618 ft2	34,510 ft2
ECM87	Typical Lighting Project in Existing Bldg - Recreation	0 ft2	0 ft2	0 ft2	0 ft2	0 ft2	0 ft2
ECM88	Typical Lighting Project in Existing Bldg - Warehouse	0 ft2	11,460 ft2	26,739 ft2	30,559 ft2	30,559 ft2	99,316 ft2

Exhibit 2: Participation Projections – Prescriptive LED Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM92	Commercial 12W LED A19 Bulb	0 units	555 units	1,295 units	1,480 units	1,480 units	4,810 units
ECM93	Commercial 8W LED A19 Bulb	0 units	1,184 units	2,763 units	3,157 units	3,157 units	10,261 units
ECM94	Commercial LED MR16 Bulbs	0 units	925 units	2,158 units	2,467 units	2,467 units	8,016 units
ECM95	Commercial LED PAR30 Bulbs	0 units	740 units	1,727 units	1,973 units	1,973 units	6,413 units
ECM96	Commercial LED PAR38 Bulbs	0 units	538 units	1,256 units	1,435 units	1,435 units	4,664 units
ECM97	Commercial Spot or task lighting	0 units	370 units	863 units	987 units	987 units	3,206 units

Exhibit 3: Participation Projections – Lighting Redesign and Custom Lighting Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM912	Gov. Lighting Redesign Study	11,394 ft2	59,232 ft2	95,676 ft2	95,676 ft2	47,838 ft2	309,815 ft2
ECM802	Gov. Typical Lighting Project in	0 ft2	11,738 ft2	31,786 ft2	36,327 ft2	36,327 ft2	116,179 ft2
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health	0 ft2	4,421 ft2	10,316 ft2	11,789 ft2	11,789 ft2	38,315 ft2
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education	0 ft2	32,136 ft2	74,984 ft2	85,696 ft2	85,696 ft2	278,512 ft2
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation	0 ft2	5,798 ft2	13,528 ft2	15,461 ft2	15,461 ft2	50,247 ft2
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse	0 ft2	3,820 ft2	8,913 ft2	10,186 ft2	10,186 ft2	33,105 ft2

Exhibit 4: Participation Projections – Prescriptive LED Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM922	Gov. Commercial 12W LED A19 Bulb	0 units	299 units	697 units	797 units	797 units	2,590 units
ECM932	Gov. Commercial 8W LED A19 Bulb	0 units	638 units	1,488 units	1,700 units	1,700 units	5,525 units
ECM942	Gov. Commercial LED MR16 Bulbs	0 units	498 units	1,162 units	1,328 units	1,328 units	4,316 units
ECM952	Gov. Commercial LED PAR30 Bulbs	0 units	398 units	930 units	1,063 units	1,063 units	3,453 units
ECM962	Gov. Commercial LED PAR38 Bulbs	0 units	290 units	676 units	773 units	773 units	2,511 units
ECM972	Gov. Commercial Spot or task lighting	0 units	199 units	465 units	531 units	531 units	1,727 units

High Efficiency Refrigeration Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 42)*

Exhibit 5: Participation Projections – High Efficiency Refrigeration Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM98	Typical Low-Cost No-Cost Refrigeration Project - Food	0 ft2	0 ft2	30,582 ft2	0 ft2	30,582 ft2	61,163 ft2
ECM99	Typical Deep Retrofit	0 ft2	0 ft2	30,252 ft2	0 ft2	30,252 ft2	60,505 ft2

Exhibit 6: Participation Projections – High Efficiency Refrigeration Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM1002	Typical Refrigeration Project - Ice Rink	0 ft2	0 ft2	24,760 ft2	0 ft2	24,760 ft2	49,520 ft2

Energy Star Computer Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 42)*

Exhibit 43: Participation Projections – ENERGY STAR Computer Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM101	ES Desktop Computer and Monitor	45 units	283 units	461 units	0 units	0 units	788 units
ECM102	ES Laptop Computer	30 units	188 units	307 units	0 units	0 units	525 units

Exhibit 44: Participation Projections – ENERGY STAR Computer Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM1012	Gov. ES Desktop Computer and Monitor	178 units	1,130 units	1,844 units	0 units	0 units	3,153 units
ECM1022	Gov. ES Laptop Computer	119 units	754 units	1,229 units	0 units	0 units	2,102 units

New Construction Incentive - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 57)*

Exhibit 7: Participation Projections – Electricity-Efficient New Construction Incentive for Non-Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM89	Typical High-Performance New Building - 25% Better	0 ft2	1,992 ft2	8,966 ft2	13,947 ft2	15,939 ft2	40,844 ft2
ECM90	Typical High-Performance New	0 ft2	311 ft2	1,401 ft2	2,179 ft2	2,490 ft2	6,382 ft2

Exhibit 8: Participation Projections – Electricity-Efficient New Construction Incentive for Government Buildings

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM892	Gov. Typical High-Performance New Building - 25% Better	0 ft2	1,073 ft2	4,828 ft2	7,510 ft2	8,583 ft2	21,993 ft2
ECM902	Gov. Typical High-Performance	0 ft2	168 ft2	754 ft2	1,173 ft2	1,341 ft2	3,436 ft2

Residential Programs

LED Lighting and Automotive Block-Heater Timers - *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 76)*

Exhibit 9: Participation Projections – LED Lighting and Block-Heater Timer Rebates

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM151	Block Heater Timer	0 units	68 units	109 units	109 units	109 units	395 units
ECM24	12W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM60	8W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM61	LED MR16 Bulbs	55 units	259 units	259 units	259 units	259 units	1,089 units
ECM62	LED PAR30 Bulbs	14 units	79 units	79 units	79 units	79 units	328 units
ECM63	LED PAR38 Bulbs	10 units	59 units	59 units	59 units	59 units	246 units
ECM44	Spot or Task Lighting	9 units	41 units	41 units	41 units	41 units	172 units

Low Cost Energy Efficiency Products - *(Ref: Yukon Five Year Demand Side Management Plan//Appendix E/page 86)*

Exhibit 10: Participation Projections –Low-cost Energy Efficient Products

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM242	Pilot 12W LED A19 Bulb	60 units	60 units	60 units	60 units	60 units	300 units
ECM602	Pilot 8W LED A19 Bulb	60 units	60 units	60 units	60 units	60 units	300 units
ECM612	Pilot LED MR16 Bulbs	40 units	40 units	40 units	40 units	40 units	200 units
ECM622	Pilot LED PAR30 Bulbs	30 units	30 units	30 units	30 units	30 units	150 units
ECM632	Pilot LED PAR38 Bulbs	20 units	20 units	20 units	20 units	20 units	100 units
ECM442	Pilot Spot or Task Lighting	6 units	6 units	6 units	6 units	6 units	30 units
ECM092	Pilot Ultra Low-flow Showerheads	30 units	40 units	30 units	20 units	20 units	140 units
ECM112	Pilot Smart, Surge Protected Power Bars for PCs and TVs	60 units	60 units	40 units	40 units	30 units	230 units
ECM182	Pilot DHW Tank Insulation	40 units	60 units	60 units	40 units	40 units	240 units
ECM202	Pilot DHW Pipe Insulation	40 units	60 units	60 units	40 units	40 units	240 units
ECM482	Pilot Motion Detectors - Indoor and Outdoor	60 units	60 units	40 units	40 units	30 units	230 units
ECM152	Pilot Auto Heater Timers	30 units	60 units	60 units	60 units	60 units	270 units
ECM142	Pilot Prog. Thermostats (Central)	10 units	20 units	15 units	10 units	10 units	65 units
ECM212	Pilot Prog. Thermostats	50 units	90 units	80 units	60 units	40 units	320 units
ECM062	Pilot E-Star TVs	2 units	2 units	2 units	2 units	2 units	10 units
ECM082	Pilot ESTAR Printers and Fax	4 units	4 units	4 units	4 units	4 units	20 units
ECM091	Ed. Ultra Low-flow Showerheads	45 units	92 units	102 units	112 units	112 units	464 units
ECM111	Ed. Smart, Surge Protected Power Bars for PCs and TVs	117 units	505 units	525 units	525 units	535 units	2,207 units

CCHP and GSHP Initiative - *(Ref: Yukon Five Year Demand Side Management Plan/Appendix E/page 94)*

Exhibit 11: Participation Projections – CCHP and GSHP Initiatives

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM032	Pilot Cold Temp Heat Pumps	1 units	0 units	0 units	1 units	0 units	2 units
ECM372	Pilot Ground Heat Pumps - Closed	0 units	1 units	1 units	0 units	0 units	2 units
ECM03	Cold Temp Heat Pumps	0 units	0 units	0 units	6 units	6 units	12 units
ECM37	Ground Heat Pumps - Closed	0 units	0 units	0 units	1 units	1 units	2 units

WL-YECL-1

Reference: 2013 Revenue Shortfall, Section 12

The Phase 1 GRA test years are 2013 to 2015 but the application was not filed until May 27th and the interim rate rider (Rider R) did not go into effect until July 1st. YECL intended to collect 50% ($1,825,000) of the total non-fuel portion of its 2013 revenue shortfall of $3,649,000 through Rider R in the period from July 1st to December 31st. YECL does not state if, or how, it intends to seek recovery of the other 50% of its 2013 revenue shortfall, which would have been accumulated in the pre-interim rate period of January 1st to June 30th.

Request:

(a) Please indicate if, and how, YECL intends to seek recovery of the other 50% of its 2013 revenue shortfall that is not recovered through interim rate Rider R.

(b) If YECL does intend to seek recovery of the other 50% of its 2013 revenue shortfall then please explain upon what basis, legal and/or otherwise, it is expecting the YUB to engage in retroactive ratemaking and allow such a recovery.

Response:

(a) Similar to the process used in Yukon Electrical's 2008-2009 GRA compliance filing (approved in Board Order 2009-05) as well as Yukon Energy's 2012/13 GRA compliance filing (approved in Board Order 2013-04) for truing up revenue collected on interim rates and the final approved revenue requirement, Yukon Electrical intends to reconcile the difference between the approved 2013 revenue shortfall and the revenue collected through interim rate Rider R shortly after final approval of the revenue requirement has been received from the Board. The balance to be collected from or refunded to customers will be addressed using the Revenue Shortfall/Surplus Rider, Rider G.

(b) In light of s. 29(b) of the Yukon Territory's *Public Utilities Act* (the "PUA"), Yukon Electrical is not by seeking recovery of the other 50% of its 2013 revenue shortfall that is not recovered through interim rate Rider R asking the YUB to "engage in retroactive ratemaking" as alleged. Section 29(b) of the PUA expressly permits the Board, should it find it just and reasonable, to approve a

utility to recover 100% of its approved revenue requirement for the year in which a proceeding is initiated for the fixing of rates. Section 29(b) states:

> 29(b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable;
>
> [Emphasis added]

The above provision is a clear exception to the principle against retroactive ratemaking and establishes the year in which the proceeding was initiated as the relevant period for consideration and recovery of any revenue shortfall arising prior to July 1, 2013, when interim rates came into effect under Rider R, need not be considered as recovery in respect of a past period. Further, under the present circumstances, Yukon Electrical submits that recovery for the period prior to July 1, 2013 is just and reasonable. Yukon Electrical filed its Application on May 27, 2013 in accordance with the PUA and in a manner that results in significant regulatory efficiencies that make it just and reasonable for the Board to exercise its discretion under Section 29(b) of the PUA to allow Yukon Electrical to recover its revenue deficiency for the whole of 2013. Such regulatory efficiencies are as follows:

- Yukon Electrical has requested approval of a three-year test period for regulatory efficiency and to reduce the costs of regulation, as discussed on pages 1-3 and 1-4 of its Application. The three year annual amortization cost of $139,000 compares favourably to the two year annual amortization cost of $208,500. In preparing its three-year test period from 2013-2015, the importance of the 2012 actuals cannot be overstated. Given the relatively small size of Yukon Electrical, modest changes in its sales, expenses or capital costs can have an impact on its overall revenue requirement. Accordingly, having the 2012 actuals prior to filing provides Yukon Electrical the best information to understand its three-year test period forecast, shortfall and rate drivers. Filing before the end of 2012 would have required Yukon Electrical to forecast 2012 as well as the test period and would have likely resulted in Yukon Electrical filing for only a two-year (2013-2014) test period. This would have resulted in less regulatory efficiency and higher costs of regulation as, due to its extensive capital program planned for 2015, Yukon Electrical would likely have been forced to file another GRA for a test period beginning in 2015.

- If the Application had been filed prior to January 1, 2013, Yukon Electrical would invariably have been requested by the Board and Interveners to provide 2012 actuals and explain the impact of the 2012 actuals, which would have resulted in a duplication of work as a result of having to provide both a detailed 2012 forecast at the time of filing and then detailed 2012 actuals. By filing its Application after the availability of 2012 actuals, Yukon Electrical submits that this unnecessary duplication of work and associated expenditure of resources by all parties involved in these proceedings, including the Board and Interveners, has been avoided. In particular, Yukon Electrical submits that administrative economy is promoted as the Board and Interveners do not have to spend the time and money associated with reviewing and forming views on two sets of information.

- In Board Order 2009-2, Yukon Electrical was directed to tie its ROE for 2008-2009 to the BCUC benchmark ROE. Yukon Electrical believes that a formula approach such as this with respect to ROE is efficient from a regulatory perspective and reduces the costs of regulation in the Yukon, as expert witnesses are not required to prepare evidence and testify on behalf of either the Applicant or Interveners. Yukon Electrical was aware at the time of preparing its filing that a BCUC Generic Cost of Capital (GCOC) decision, which would update the benchmark ROE that had not been updated since 2009, was imminent. Yukon Electrical chose to delay its filing for a short period in order to incorporate the result of the BCUC GCOC proceeding (Order G-75-13), issued on May 10, 2013, into its filing.

- Additionally, Yukon Electrical's request for approval and recovery of a revenue requirement and revenue requirement shortfall for calendar year 2013 is consistent with the following applications which were filed subsequent to the start of the test period:

    - Yukon Electrical 2008-2009 GRA – filed April 30, 2008 (recovery as of January 1, 2008);

    - Yukon Energy 2008-2009 GRA – filed October 6, 2008 (recovery as of January 1, 2008); and

    - Yukon Energy 2012-2013 GRA – filed April 27, 2012 (recovery as of January 1, 2008).

WL-YECL-2

Reference: Section 1, Schedules 8.8 and 8.9

On page 1-4, YECL states that the 3-year amortization cost of the Phase 1 GRA is $139,000 and that choosing a 3-year test period produces annual savings of $69,500 compared to a 2-year test period.

Request:

(a) Please indicate where in the schedules provided with the GRA the 3-year annual amortization cost of $139,000 is shown. If it is not shown in any schedule provided then please provide such a schedule that also shows the proposed annual amortization costs of the Phase 2 GRA.

(b) There was a 3-year gap (2010-2012) between GRA test years (2009 – 2013). Assuming the 1st test year of the next Phase 1 GRA is not until 2017, 2018 or 2019, please estimate the savings if the 2013-2015 Phase 1 and Phase 2 GRA costs are amortized over periods that end in 1) 2016, 2) 2017 and 3) 2018.

Response:

(a) The proposed three year amortization of the forecast Phase I and Phase 2 costs are reflected in the calculations on Schedule 8.8 of Yukon Electrical's Application.

Forecast Phase 1 costs = $417,000 / 3 years = $139,000/year
Forecast Phase 2 costs = $193,000 / 3 years = $64,333/year

The above noted amortizations result in the Rate Case Deferral Account reaching a zero balance at the end of the 2015 test period.

(b) The forecast savings of amortizing the costs over 4, 5 and 6 year period (2016, 2017 and 2018), respectively, are:

4 years (2016) = ($417,000+$193,000) / 4 years = $152,500/year
($139,000+$64,333) - $152,500 = $50,833 savings/year

5 years (2017) = ($417,000+$193,000) / 5 years = $122,000/year
($139,000+$64,333) - $122,000 = $81,333 savings/year

6 years (2018) = ($417,000+$193,000) / 6 years = $101,667/year
($139,000+$64,333) - $101,667 = $101,666 savings/year

WL-YECL-3

Reference: Costs Related to Board Orders or Legislative Provisions Page 1-6

YECL states: *"Yukon Electrical also seeks the ability to flow-through (dollar for dollar) to the tariff any costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that Yukon Electrical operates under, or that bear on the nature and extent of Yukon Electrical's obligations as a regulated utility and which impact its 2013-2015 revenues or revenue requirement."*

Request:

(a) Please explain why YECL is asking for this ability. Was there a precipitating event that led YECL to ask for this ability?

(b) Please explain why these costs cannot be dealt with as they arise rather than YECL being provided with the blanket ability to flow-through these costs without seeking Board approval.

(c) Please provide further details and examples of the types of costs that YECL envisions being captured by this ability. How would this ability be put into practice? Also, what types of costs would not be captured by this ability?

(d) Rather than the blanket ability to flow through these costs should there instead be thresholds established: 1) a minimum threshold below which YECL would be expected to absorb these costs as part of its regulatory and business risk and 2) a maximum threshold above which Board consideration and approval is required?

Response:

(a) This deferral has been requested by Yukon Electrical in order to maintain consistency with a similar deferral that was approved as part of Northland Utilities (Yellowknife) and Northland Utilities (NWT) 2011-2013 GRAs in Decisions 13-2011 and 17-2011, respectively. In those decisions, the approved wording of the deferral was as follows:

> …a deferral account which would be used to record amounts associated with any Board decisions that result in changes to the rules or parameters that Northland operates under, including such areas as the billing system, collection practices or the frequency of meter reading, or statutory or legislative provisions or changes that bear on the nature and extend of Northland's regulated utility obligations or operations and which impact Northland's 2011-2013 Revenues and/or Revenue Requirements. For clarity, no such recorded amounts would be approved by the Board as part of this Negotiated Settlement. Rather, the balance(s) would be brought forward by Northland for consideration in Northland's next General Rate Application.

(b) Yukon Electrical has not requested that it be provided blanket ability to flow-through these costs without seeking Board approval. Any balance(s) would be brought forward by Yukon Electrical for consideration in Yukon Electrical's next General Rate Application.

(c) Yukon Electrical envisions the following potential examples where this deferral might be employed:

- Board or government ordered changes to the Yukon's rate structure that, in turn, require changes to the billing system;
- Board Orders resulting in changes to billing and collection practices;
- Board Orders resulting in changes in the frequency of meter reading; and
- Legislative changes to environmental or safety regulations.

Yukon Electrical would accumulate costs relating to the above examples and bring them forward for consideration as part of a future application.

As detailed in its Application, this deferral would only address costs incurred as a result of Board Orders or changes in legislative provisions that bear on the nature and extent of Yukon Electrical's obligations as a regulated utility and which impact its 2013-2015 revenues or revenue requirement.

(d) As noted in the response to part (b) of this question, Yukon Electrical has not requested that it be provided blanket ability to flow-through these costs without seeking Board approval. Any balance(s) would be brought forward by Yukon Electrical for consideration as part of a future application.

WL-YECL-4

Reference: Key Assumptions – Inflation, Table on Page 1-6

The Table on Page 1-6 provides a list of assumptions used by YECL is preparing the GRA.

Request:

(a) Please provide further support and reasoning for YECL's assumption that the 2015 labour inflation rate should be 3.5%.

(b) Please explain the rationale for YECL's approach to calculating "Other Inflation". Specifically, why does YECL choose to use Alberta inflation values in calculating its inflation rate for Yukon? What evidence is there that Alberta provides a better approximation than B.C.? Are inflation estimates now available for Yukon for 2014 and 2015? If yes, please provide them. If no, when will they be available?

Response:

(a) A review of collective agreements for other utilities was carried out to review those that provide visibility on increases negotiated for 2015. This research provided the following results:

Company	2015 Increase
AltaLink	4.0%
Capital Power	3.5%
EPCOR	3.5%
TransAlta	3.0%

Of the limited amount of data available forward to 2015, these indicators play a role in one of the market areas that Yukon Electrical competes with for skilled labour.

(b) Yukon Electrical bases half of its "Other Inflation" forecast on Alberta inflation values as it purchases a significant amount of goods and services from Alberta due to the fact that its parent company is located in Alberta. This was affirmed by the Board on page 16 of Appendix A to Board Order 2009-2.

Yukon Electrical was unable to locate any inflation forecasts for the Yukon for 2014 and 2015 and does not have any information as to when they will be available.

WL-YECL-5

Reference: Staffing Levels, Pages 1-7 to 1-13, Section 1 Attachment 1

Northland proposes to increase its staffing level by 16 FTEs from 2009 to 2015. Descriptions are provided for individual positions but there is no broad overview of what is driving this large increase in staffing.

Request:

(a) Taking a big picture approach that considers communities served, customers served, power sales, customer complaints, etc. please describe the conditions that are driving a 16 FTE increase in staffing levels in just 6 years.

(b) Please explain why the General Manager is a 0.8 FTE.

(c) Please explain what position(s) previously fulfilled the functions now assigned to the Senior Corporate Communications Advisor? Why was that arrangement deemed insufficient such that this new position was determined necessary? Many of the tasks assigned to this position do not appear to require the skills of a senior-level employee so please explain why this is a senior-level position. Why is this position a 0.6 FTE?

(d) Please provide further support for the need to add a financial analyst in 2011.

(e) Please provide support in terms of communities and customers served to support the need for another meter reader in 2012. At what point were the two meter readers unable to fulfill their responsibilities?

(f) Part of the justification for adding a Manager, Financial Reporting and Accounting, North of 60, was the work required to transition to IFRS. Once that transition is complete, will this position be eliminated? If no, why not? Also please provide support to the claim that the regulatory burden is increasing to justify this position.

(g) Part of the justification for adding a Corporate Accountant was the work required to transition to IFRS. Once that transition is complete, will this position be

eliminated? If no, why not? Also please provide support to the claim that the regulatory burden is increasing to justify this position.

(h) Please explain why the Manager, Financial Reporting and Accounting, the Supervisor, Financial Services, and the Corporate Accountant positions were created in ATCO Electric instead of having those positions in YECL and based in Yukon to support the economy and communities in Yukon.

(i) Please explain what position previously fulfilled the responsibilities of the Construction Lead and why that arrangement was no longer suitable.

(j) Did the creation of the Engineering Tech Civil 1 reduce the overall costs for YECL? Please demonstrate with calculations.

(k) Were customer service metrics not being met such that the new Customer Service Advisor position is required in 2013? Please explain.

(l) Please explain why the responsibilities of the Customer Service Representative could not be distributed amongst the Customer Service Advisors and/or the Supervisor, Customer Accounting and Administration.

(m) Please explain why the responsibilities of the Environmental Technician could not be added to the responsibilities for the Engineering Tech 1 Civil and/or fulfilled through the use of contractors.

(n) The rationale cited for many of the new positions has been growth in the capital program. If the level of growth is not sustained, how frequently will YECL review its staffing levels to eliminate/consolidate positions so that staffing levels are not excessive?

Response:

(a) In its Application, Yukon Electrical has provided descriptions of the need for each of the positions created and filled from 2009 through to 2012 as well as forecast positions through to 2015. The major themes for the growth in staff complement include growth in capital expenditures, growth in system being operated and maintained, growth in the number of customers, the implementation of a demand side management program, development of alternative energy and net metering

initiatives as well as increased operational regulatory due diligence associated with a new water licence and associated environment regulations relating to the construction and operation of distribution and generation assets in the Yukon.

Please refer to LE-YECL-2(b) Attachment 1 for additional information on Yukon Electrical's growth since 2009.

(b) The General Manager position is responsible for Yukon Electrical as well as Northland Utilities (Yellowknife) and Northland Utilities (NWT). The time spent on Northland matters averages 1 day per week.

(c) Please refer to YUB-YECL-22(d).

(d) The Financial Analyst was needed in 2011 to provide a wide range of financial and operational functions to Yukon Electrical including helping to prepare variance analysis of operations and maintenance expenditures as compared to forecast. Further to this, additional support was needed to help manage Yukon Electrical's growing capital program including variance analysis and the preparation of economic analysis where applicable.

(e) The communities that are served directly by the additional Meter Reader position are Whitehorse, Marsh Lake, Tagish, and Carcross and surrounding areas, as well as Deep Creek. At the end of 2012, there were 13,688 meters to read every month for these areas. Increases in additional meters on a number of meter reading routes increased the workload to more than the 8 hour work days for the two Meter Reader positions. Prior to the creation of the additional meter reading position, additional support for reading meters was provided by Field Service Representatives or Powerline Technicians. This situation was not a good use of their technical skills and impacted their ability to complete their regular duties.

(f) This new 0.5 FTE manager position will not be eliminated once the transition to IFRS is completed. Yukon Electrical fully implemented IFRS at the beginning of 2011. The Manager, Financial Reporting and Accounting, North of 60 position was added in mid-2012. This position was added after the transition to IFRS was completed, once the increased volume of on-going work related to IFRS and project support work as well as forecast regulatory activities was known.

With respect to IFRS, Yukon Electrical is now required to maintain two sets of financial records as a result of the various items which require different treatment

for regulatory and financial statements purposes. The transition to IFRS was not simply a one-time project that was completed and then workload returned to pre-IFRS levels. Maintaining two sets of records adds complexity and additional reconciliation requirements to reporting for both regulatory and financial statement purposes. As well, there are now two sets of "rules" that accountants at Yukon Electrical have to understand and consider when recording transactions.

With respect to new project support work, this position is responsible to provide complete financial and business support in the development of all new initiatives, including such projects as LNG, net metering and IPP development.

With respect to regulatory, it is clear to Yukon Electrical that interveners are looking for ever increasing levels of granularity when it comes to the testing of past as well as forecast expenditures. This situation is demonstrated in Yukon Electrical's recent GRAs. For its 2008-2009 GRA, Yukon Electrical submitted an Application that was 372 pages long. For its 2013-2015 GRA, Yukon Electrical submitted an Application that was 1,881 pages long. Even without the 1,221 pages of the Application that contained the Yukon Five Year Demand Side Management Plan, the Application included an additional 288 pages of content or 77% more than the previous Application. Despite the additional information provided in its Application, Yukon Electrical still received 60% more Information Requests (1,128 in the current proceeding versus 707 in the 2008-2009 GRA proceeding). Responding to such a high volume of detailed IRs is a significant undertaking that requires the involvement of this position especially when considering Yukon Electrical does not hire outside consultants when completing the vast majority of this work.

In addition to helping lead and complete Yukon Electrical's 2013-2015 GRA, this position will also be a key resource in providing support for Yukon Electrical's next Phase II Application, currently forecast to occur in 2014, as well as any Yukon Electrical involvement in future Yukon Energy applications that impact Yukon Electrical and its customers such as: General Rate Applications, new Power Purchase Agreements, or other applications such as the recently directed Diesel Contingency Fund and Rate Schedule 42 process. With the exception of legal, Yukon Electrical does not use outside consultants to complete this work.

(g) As discussed in part (f), Yukon Electrical has already completed its transition to IFRS and the increase in workload, including that resulting from maintaining two

sets of books, is on-going. The Corporate Accountant, similar to the Manager, Financial Reporting and Accounting, North of 60, was added in 2012 once it was clear that it was not sustainable to have only one position working on all accounting, financial reporting and regulatory issues. Please also refer to part (f) for comments on the ongoing work needed to be completed for regulatory purposes.

(h) The Manager, Financial Reporting and Accounting is the position that oversees the regulatory and reporting functions for Yukon Electrical as well as for Northland Utilities (Yellowknife) and Northland Utilities (NWT). As the accounting support teams for the two Northland companies are located in Edmonton, as well as the relocation of the Supervisor, Financial Services position for Yukon Electrical to Edmonton as discussed below, Edmonton was considered to be the best location for the position.

The Supervisor, Financial Services has historically been a Yukon Electrical employee based in Whitehorse. When the position became vacant in 2009, Yukon Electrical was unable to find a suitably experienced candidate in the Yukon. A candidate located in Alberta was, however, identified who was willing to relocate to Whitehorse. When the position again became vacant in late 2011, Yukon Electrical was unable to find a new candidate who was willing to be based in the Yukon. A previous Yukon Electrical employee who had since relocated to Edmonton was, however, available to fill the position. As a result of this series of events, the Supervisor, Financial Services position is now being filled by an ATCO Electrical employee based in Edmonton.

The Corporate Accountant position was created in ATCO Electric as a result of the direct supervisor for the position, the Supervisor, Financial Services, being located in Edmonton when the position was filled.

(i) The Coordinator, Construction and Materials Management previously completed the tasks the Construction Lead is assigned now. With the increase in capital work and restructure of the Construction department, the tasks and workload were not able to continue to be done by the Coordinator, Construction and Materials Management as the role developed into the Construction Supervisor position.

(j) The creation of the Engineering Tech Civil 1 was to reduce dependency on external contractors and consultants. This position has the lead responsibility for

the Fish Lake Hydro system in scheduling and managing each infrastructure project to completion. The position also ensures all water management reporting, ongoing monitoring and the necessary reports are completed and given to the proper regulatory body.

The costs of various local consultants and contractors range from $60 - $225/hour as indicated by WL-YECL-5(j) Attachment 1.

(k) The primary reason for the new Customer Service Advisor position is due to the steady increase of customers. Yukon Electrical had 4 Customer Service Advisors to provide service for all customer requests as well as billing and account information services to approximately 12,000 customers. Yukon Electrical now has close to 17,000 customers. Each Customer Service Advisor provides direct customer service to 3,400 customers for billing and account inquiries as well as processing customer requests such as reconnects, disconnects and general service inquiries.

(l) The Customer Service Representative will be responsible to work with new customers on the development of their project to connect to the Distribution System. As such, the requirements of this position will include understanding Yukon Electrical's engineering standards and design, project estimating and process as well as the Terms and Conditions of Electrical Service. The requirements of this position also include meeting customers in the field to receive input and guidance on the customer's electrical needs. The Supervisor, Customer Accounting and Administration and the Customer Service Advisors provide billing and account services in an office setting as opposed to the construction related activities that will be done by the Customer Service Representative.

(m) The Environmental Technician requires a background in environmental studies and applicable environmental regulations as this position will have full responsibility to apply, monitor and report on all of Yukon Electrical's environmental permits and studies. The duties are too great to add on to another position including the Engineering Tech 1 Civil. It was also determined that with increased reporting, permitting and monitoring it was prudent to bring this skill set in house as Yukon Electrical is forecasting these activities to continue as a normal part of doing business in the Yukon.

(n) Yukon Electrical reviews its staffing levels on an annual basis and more often as required. If the capital program does not continue as forecast, capital and construction resources would be redeployed or contractor resources reduced to ensure Yukon Electrical's capital related staffing levels are matched to its needs.

Hourly Rates of Local Consultants and Contractors

Engineering Consultants	Company A	Company B	Company C	Company D	Company E	Company F	Company G	Company H	Company I	Company J	Company K	Company L
Type of work	Consultants	Survey/Drafting	Heritage Resource Survey	Environmental Consulting	Hydrometric Systems/Monitoring	Heritage Resource Survey	Consultants	Hydrological Consultation	Mechanical/Electrical	Engineering Services	Survey/Drafting	Survey/Drafting/Design
Engineer 1	$ 110									$ 75		
Engineer 2	$ 120											
Engineer 3	$ 135								$ 126	$ 90		$ 110
Engineer 4	$ 165				$ 125		$ 150	$ 154	$ 145			$ 130
Engineer 5	$ 185						$ 170		$ 185	$ 120		$ 160
Engineer 6	$ 225											
Technologist 1	$ 90								$ 105			
Technologist 2	$ 105								$ 115			
Technologist 3	$ 115											
Technologist 4	$ 130								$ 125			
Surveyor		$ 153										
Senior Survey Technologist		$ 112									$ 113	$ 90
Survey/CADD Technologist		$ 85							$ 70		$ 71	$ 90
Senior Archaeologist			$ 85			$ 85						
Archaeological Technician			$ 65			$ 75						
Senior Biologist				$ 125								
Biologists				$ 95								
Technician				$ 75	$ 85							
Drafting										$ 55	$ 64	
Project Manager - Construction										$ 100		

WL-YECL-6

Reference: Treatment Under IFRS vs Regulatory, Section 1 Attachment 2

The Table in Attachment 3 provides a comparison of the treatment of significant items for Financial Statement purposes and regulatory purposes, post IFRS. Watson Lake wishes to understand the reasons for any differences in IFRS treatment of significant items by YECL and ATCO Electric Ltd.

Request:

(a) Please indicate whether the treatment of the significant items under IFRS for Financial Statement purposes, as set out in the Table in Attachment 2 is consistent with treatment of the same items for financial statement purposes by YECL's parent, ATCO Electric Ltd or its affiliates Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd. If there are differences please identify the differences and the reasons for them.

(b) Please indicate whether the treatment of the significant items for regulatory purposes as set out in the Table in Attachment 2 is consistent with treatment of the same items for regulatory purposes by NUL's parent, ATCO Electric Ltd. and its affiliates NUL(YK) and NUL(NWT). If there are differences please identify the differences and the reasons.

(c) Please indicate how revenues that are interim as of fiscal year-end are treated for Financial Statement purposes under IFRS. Indicate whether there has been any change in the Financial Statement treatment of revenues that remain unapproved as of fiscal year end, due to regulatory lag, as a result of the transition from GAAP to IFRS. Please elaborate.

Response:

(a) Yukon Electrical's treatment of significant items under IFRS for Financial Statement purposes, as set out in the Table in Attachment 2 of its Application, is consistent with the treatment of the same items by Yukon Electrical's parent, ATCO Electric Ltd., and its affiliates, Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd.

(b) Yukon Electrical's treatment of significant items for regulatory purposes, as set out in the Table in Attachment 2 of its Application, is consistent with the treatment of the same items by Yukon Electrical's parent, ATCO Electric Ltd., and its affiliates, Northland Utilities (YK) Ltd. and Northland Utilities (NWT) Ltd.

(c) A summary of the recording of revenues under IFRS and historical Canadian GAAP ("historical GAAP") is as follows:

- Under IFRS as well as historical GAAP, interim revenues are (were) recorded as revenues when billed to customers.

- For revenues that remain unapproved as of current fiscal year end, revenues could not be recorded under historical GAAP nor can they be recorded under IFRS.

- For revenues that are approved as of fiscal year end but are to be collected prospectively in the next fiscal year, historical GAAP allowed them to be recorded as a regulatory receivable at year end. In the case of IFRS, regulatory assets, such as revenue receivables, are written-off at year end. Revenues can only be recorded as revenues when they are billed to customers.

WL-YECL-7

Reference: Treatment Under IFRS vs Regulatory, Page 1-13

YECL, consistent with its parent company, has chosen not to recognize any regulatory assets and liabilities in its Financial Statements starting in 2011. The absence of the recognition of regulatory deferral accounts will result in increased volatility in IFRS based earnings. The IFRS based Financial Statement to utility earnings reconciliation will involve separately tracking the effects of writing off regulatory assets and liabilities. This will add more complexity and time to all of YECL's accounting functions.

Request:

(a) Please explain why YECL and its parent decided not to recognize any regulatory assets and liabilities in the Financial Statements. Is this the same approach taken by NUL(YK) and NUL(NWT)? Please explain why it was considered prudent to incur the additional costs of annual reconciliations as a result of this treatment.

(b) Please identify the direct and indirect additional costs, in each test year, resulting from the added complexity and time due to the need for separately tracking significant items for regulatory and Financial Statement purposes.

Response:

(a) Yukon Electrical, consistent with its parent companies, ATCO Electric Ltd. and CU Inc., has chosen not to recognize any regulatory assets and liabilities in its Financial Statements in order to comply with the new IFRS accounting standards. These standards require that Yukon Electrical's financial statements be prepared using accounting policies consistent with IFRS as issued by the International Accounting Standards Board ("IASB") and interpretations of the IFRS Interpretations Committee ("IFRIC"). In the absence of a rate regulated standard under IFRS, Yukon Electrical and its parents do not recognize assets and liabilities from rate regulated activities as may be directed by regulatory decisions. Revenues are recorded in earnings when amounts are billed to customers through customer rates consistent with the underlying rate design as mandated by the regulator. Operating costs and expenses are recorded when incurred.

This approach is consistent with that taken by Yukon Electrical's affiliate companies, NUL(YK) and NUL(NWT).

While the above noted changes to comply with IFRS accounting standards result in additional complexities, reconciliations and time to complete financial accounting reporting functions, the costs associated with these activities are prudently incurred because:

- Yukon Electrical requires an unqualified financial statements audit opinion from its external auditors to give readers the assurance Yukon Electrical is appropriately reflecting IFRS in its accounts;

- Yukon Electrical's unqualified audit opinion support ATCO Electric and CU Inc. obtaining unqualified audit opinions; and

- An unqualified audit opinion for CU Inc. supports CU Inc.'s ability to access capital markets to finance capital growth for all of CU Inc.'s regulated utilities, including Yukon Electrical, at favourable rates.

(b) In 2011, all IFRS transition-related work was handled by the Supervisor, Financial Services. As such, no incremental costs were incurred. In 2012, the Corporate Accountant and Manager, Financial Reporting and Accounting, North of 60 positions were added. Yukon Electrical estimates that approximately 10% of the Corporate Accountant's workload and 5% of the workload for each of the Supervisor and Manager is related to IFRS in 2012. The approximate cost of the time spent on IFRS in 2012 was $43,000. On a go forward basis, the time spent on IFRS is expected to remain consistent with 2012. As a result, for 2013, 2014, and 2015, the approximate cost of the time spent on IFRS is $44,500, $46,000 and $47,500, respectively, based on a labour inflation rate of 3.5% per year.

WL-YECL-8

Reference: Sales and Revenues, Section 2

The Board would like further support with respect to the customer forecasts and regression analysis

Request:

(a) Please expand Table 1 to include 2008, 2009 and 2010 and also to show the sales variances in each year subsequent to 2008 (so 2009 to 2015) caused by 1) the change in number of customers, 2) the change in consumption per customer (normalized for residential) and 3) the impact of the demand side management program. For 2013 to 2015 this analysis should be presented relative to the corresponding GRA forecasts.

(b) Please explain the decreasing Private Lights sales in Table 1.

(c) YECL partially attributes its increasing residential sales to increased use of electricity for space heating. Please explain the reasons for the increased interest in the use of electricity for space heating in Whitehorse. Has the interest in electricity for space heating increased in other communities? Why or why not?

(d) Please provide an analysis of the elasticity of demand for electricity for space heating relative to a range of prices of electricity (with that range including the expected $/kwh arising from this Phase 1 and the upcoming Phase 2 for the test years). This analysis should take into consideration the forecast costs for competing options for heating energy.

(e) Should cooling degree days (CDD) be a factor in forecasting electricity usage to take into account use of electricity for space cooling?

(f) Please expand Schedule 2.1 so that it presents customers, sales and revenue by community.

(g) Please explain why Section 2 Attachment 20 only shows the 20-year “Normal” HDD for Whitehorse and Watson Lake.

(h) Please provide a schedule showing the calculation of the UPC for each community (residential and commercial) from 2008 to 2015 with all calculations clearly shown and with references to Attachments 1 to 21 of Section 2.

(i) Please discuss the meaning of differences (higher vs. lower and magnitude), and the reasons for these differences, in the coefficients of HDD for the different communities.

(j) Please indicate whether there are any observable trends with respect to residential consumption per customer in each community (for example due to conservation, size of housing units, etc). Indicate whether the introduction of a trend factor into the regression analysis would help improve the R^2 values in the regression analysis. Provide all supporting analysis with respect to this response.

(k) Please indicate why 18 degrees Celsius was chosen as the balance point for temperature normalization. Please provide an analysis showing the sensitivity of the regression results to lower temperatures being used as the balance point.

(l) Given the relatively small size of some communities please indicate whether it would make sense to group the customers under single family residences and multifamily units for the purposes of the regression analysis. Does YECL have the necessary data for such analysis?

(m) Please indicate whether any 2013 published housing starts forecasts data were considered in the development of the residential sales forecast. If so, please provide the sources and the data used and show how this information was factored into the forecasts. If 2013 housing starts data was not used, please explain why not.

(n) Please provide a schedule showing the calculation of the commercial sales per community starting from the number of customers and the UPC.

(o) Please explain why temperature normalized sales were not used to arrive at the average consumption per customer for commercial customers. Please provide an analysis that would show the calculation of the commercial consumption per customer for each test year using temperature normalized sales per customer. Indicate whether the stratification of the commercial customers by size would help produce better R^2 values.

(p) Please explain the large increases in reconnect revenue starting in 2012 shown in Schedule 2.2.

Response:

(a) Please refer to WL-YECL-8(a) Attachment 1.

(b) Yukon Electrical has observed a declining trend in the actual number of private lighting customers since 2008 and therefore a declining trend in sales. Yukon Electrical does not invest in private lighting, thus the customer is responsible for 100% of the capital cost to install a new light. As a result, Yukon Electrical believes that customers are choosing alternate sources of lighting. Yukon Electrical has assumed that this trend will continue into the forecast years.

(c) Yukon Electrical has observed an increased interest in use of electricity for space heating in Whitehorse in recent years. Although Yukon Electrical is not involved with consumer's choices of heating sources for their homes, Yukon Electrical presumes that this could be related to the construction costs of installing central heating systems supplied by propane, home heating fuel or wood, versus the installation of an electric baseboard heating system. The use of electricity for space heating is not permitted in the isolated diesel communities without written permission from Yukon Electrical.

(d) Yukon Electrical has not performed an analysis of the elasticity of demand for electricity for space heating for Yukon due to the complexity of the study, lack of appropriate data and extensive amount of time it would take to perform such a study. However, based on a survey of studies reported for some jurisdictions in the U.S. by the Electric Power Research Institute titled, "Price Elasticity of Demand for Electricity: A Primer and Synthesis", dated January 2008, the elasticity of demand for general electricity use (not specifically for space heating) is estimated in the range of -0.2% to -0.6% in the short-run (1-5 years), and -0.7% to -1.4% in the long-run for residential customers, and between -0.2% to -0.7% in the short-run, and -0.8% to -1.3% in the long-run for commercial customers. Based on these numbers, for example, a 10% increase in the price of electricity of the residential rate class in the short-run would result in, everything else being constant, a 2% to 6% drop in electricity consumption by

residential customers. For commercial customers, the same increase in price in the short-run would result in, everything else being constant, a 2% to 7% drop in electricity consumption. It should be noted that these elasticity estimates were all derived for jurisdictions with enabling technologies that provide for some sort of time-variable pricing (dynamic pricing) such as Time of Use, Critical Peak Pricing, or Real Time Pricing. As such, these customers are more aware and capable to react to price changes, if they choose to do so. While Yukon Electrical's sales forecast does not incorporate reduced consumption caused from increased prices, there is a risk that actual sales will be lower than forecast.

(e) No, because CDD data is not consistently available for the 20 years that Yukon Electrical has used for the HDD variable as an input into the weather-normalization process. Also, Yukon Electrical's service area is in a cooler climate where there are very few CDD days within a year.

(f) Please refer to WL-YECL-8(f) Attachment 1 for the expanded Schedule 2.1 by Rate Zone (Hydro, Large diesel, Small Diesel and Old Crow). As the revenue forecast is calculated on a Rate Zone basis, Yukon Electrical does not have the forecast available on a community basis.

(g) Environment Canada does not provide historical HDD data, consistent with that of Whitehorse and Watson Lake, for other communities within Yukon Electrical's service area.

(h) The calculation of residential UPC by community from 2008 to 2015 is provided in WL-YECL-8(h) Attachments 1 to 21. Please refer to CW-YECL-3 for details of the commercial UPC forecast.

(i) The coefficient of HDD in each community indicates the impact of one unit change in HDD on the average electricity consumption (UPC) for a typical customer in that community. For example, in the case of Whitehorse, a one unit change in HDD leads to an estimated 0.54 kWh change in the average electricity consumption of a typical Whitehorse residential customer (Attachment 21, Page 1 of 7, of the Application). The higher the coefficient, with everything else being equal, the higher the impact of HDD would be on the average electricity consumption. In reality, however, many factors contribute to the variations in HDD coefficients among different communities. For example, different patterns and uses of electricity among different communities, such as:

- different level of penetration of electric devices among households;
- the size/mixture of the households (eg. share of young people versus older people);
- income level;
- the structure/type/size of dwelling (wood/concrete);
- single detached versus multi-family dwelling; and
- small versus large house.

(j) While the conservation efforts, size and mixture of housing units will influence the average electricity consumption in a community, it would be difficult to attribute the long-term trend in the average consumption in Yukon communities to any one factor without a careful examination and detailed study. Such a study would require detailed historical data, which is unavailable in the Yukon Territory. Yukon Electrical has not undertaken such a study, and therefore is unable to provide any comment. It should also be noted that Yukon Electrical's use of regression analysis was solely for the purpose of identifying and quantifying the impact of weather on the average consumption so that the three-year averaging method, which was utilized in forecasting the UPC, would be free from the impact of an abnormally cold/warm year. Adding a trend variable to the regression equation would depart from that purpose, and obscure the impact of the weather variable.

(k) Yukon Electrical uses 18 degrees Celsius as the balance point for temperature-normalization as it is based on the definition Environment Canada uses and provides data for heating degree days (HDD). Heating Degree Days is defined by Environment Canada as:

> "Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. If the temperature is equal to or greater than 18°C, then the number will be zero."

Yukon Electrical has always used the official data from Environment Canada and has not considered using a different balancing point other than the one officially

produced. As a result, Yukon Electrical is unable to provide an analysis showing the sensitivity of regression results to lower temperatures being used as the balance point.

(l) Yukon Electrical does not believe separately grouping customers by single family and multi-family housing would make sense, all customers in the residential rate class in a particular rate zone are charged the same rate regardless of the type of residence. In addition, Yukon Electrical does not have the necessary data available to undertake such an analysis.

(m) 2013 housing starts data was not used because at the time the forecast was being prepared there was no published report available.

(n) Please refer to CW-YECL-3.

(o) Please refer to YEC-YECL-4(c) for an explanation on how the commercial UPC was derived.

The stratification of data by size may not help produce better R^2 values if the customers in the strata are different in their use of electricity and if there business activities are not temperature-sensitive. The stratification may also introduce problems associated with a small sample size bias.

(p) The reconnect fee schedule changed in July 2011. This was part of the T&C's Schedule "D" update: The normal fee to set up an account changed from $15 to $50. Also a collection fee for visits to a delinquent customer changed from $0 to $30. Reconnect after disconnection for non-payment changed from $50 to $60.

Table 1

Yukon Electrical Sales by Customer Class[1]

	Actual									Test Period					
	2008	2009	Energy (MWh) (2009-2008)	2010	Energy (MWh) (2010-2009)	2011	Energy (MWh) (2011-2010)	2012	Energy (MWh) (2012-2011)	2013	Energy (MWh) (2012-2011)	2014	Energy (MWh) (2012-2011)	2015	Energy (MWh) (2012-2011)
Residential															
Sales (MWh)[2]	125,407	130,563	5,156	133,622	3,059	141,204	7,582	147,845	6,641	151,793	3,948	154,381	2,588	157,023	2,642
Customer	12,715	12,943	2,250	13,170	2,295	13,482	3,158	13,857	3,936	14,159	3,217	14,401	2,592	14,647	2,643
UPC(kWh)[2]	9,863	10,088	2,905	10,146	764	10,474	4,424	10,669	2,706	10,721	731	10,720	(4)	10,720	(1)
DSM Impact (MWh)[3]												88	88	402	314
Commercial															
Sales (MWh)	141,704	142,076	372	145,776	3,700	150,591	4,815	159,562	8,971	161,564	2,003	165,095	3,531	168,549	3,453
Customer	2,600	2,630	1,630	2,692	3,349	2,774	4,454	2,841	3,632	2,867	1,446	2,903	2,033	2,948	2,554
UPC (kWh)	54,496	54,018	(1,259)	54,148	351	54,278	362	56,157	5,338	56,351	557	56,867	1,497	57,172	899
DSM Impact (MWh)[3]												11	11	305	294
Street Lights															
Sales (MWh)	3,545	3,477	(68)	3,647	170	3,598	(49)	3,771	173	3,725	(47)	3,789	64	3,854	64
Private Lights															
Sales (MWh)	631	592	(39)	594	2	581	(13)	560	(20)	554	(6)	544	(10)	534	(10)
Sub-Total	**271,287**	**276,708**	**5,421**	**283,639**	**6,931**	**295,974**	**12,335**	**311,739**	**15,765**	**317,636**	**5,897**	**323,809**	**6,173**	**329,959**	**6,150**
Industrial						-		-		1,025	-	4,620	-	4,620	-
Total	**271,287**	**276,708**	**5,421**	**283,639**	**6,931**	**295,974**	**12,335**	**311,739**	**15,765**	**318,661**	**6,922**	**328,429**	**9,768**	**334,579**	**6,150**

1) With the exception of data for Residential and the DSM impact, data in this table are from Schedule 2.1.

2) Sales and UPC data are on a weather-normalized basis

3) DSM initiative is assumed to be approved and is incorporated in the sales numbers in 2014 and 2015.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Total

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Existing 2013	Test Period Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	12,715	12,943	13,169	13,482	13,857	14,159	14,401	14,647
3	Sales in MWh	128,302	130,569	131,273	141,696	150,350	151,793	154,381	157,023
4	MWh sales per customer	10.1	10.1	10.0	10.5	10.8	10.7	10.7	10.7
5	Revenue ($000s)	16,671	16,307	16,892	18,928	21,127	21,294	21,657	22,028
6	Cents per KWh	12.99	12.49	12.87	13.36	14.05	14.03	14.03	14.03
7	**Commercial**								
8	Customers (average during year)	2,600	2,630	2,692	2,774	2,841	2,867	2,903	2,948
9	Sales in MWh	141,704	142,077	145,776	150,591	159,562	161,564	165,095	168,549
10	MWh sales per customer	54.5	54.0	54.1	54.3	56.2	56.4	56.9	57.2
11	Revenue ($000s)	20,818	20,368	21,621	23,374	26,057	26,398	27,015	27,602
12	Cents per KWh	14.69	14.34	14.83	15.52	16.33	16.34	16.36	16.38
13	**Industrial**								
14	Customers (average during year)	0	0	0	0	0	1	1	1
15	Sales in MWh	0	0	0	0	0	1,025	4,620	4,620
16	MWh sales per customer						1,025	4,620	4,620
17	Revenue ($000s)	0	0	0	0	0	143	612	612
18	Cents per KWh						13.91	13.26	13.26
19	**Street lights**								
20	Sales in MWh	3,545	3,477	3,647	3,598	3,771	3,725	3,789	3,854
21	Revenue ($000s)	776	764	848	881	963	951	966	981
22	Cents per KWh	21.89	21.98	23.24	24.47	25.53	25.54	25.49	25.45
23	**Private lights**								
24	Sales in MWh	631	592	594	581	560	554	544	534
25	Revenue ($000s)	139	131	138	144	147	145	143	141
26	Cents per KWh	22.04	22.18	23.29	24.72	26.20	26.23	26.27	26.31
27	**Total Company - Retail - Primary**								
28	Customers	15,315	15,573	15,862	16,256	16,699	17,026	17,304	17,595
29	Sales in MWh	274,182	276,714	281,290	296,466	314,244	318,661	328,429	334,579
30	Revenue ($000s)	38,404	37,570	39,500	43,326	48,293	48,931	50,393	51,363
31	Cents/KWh	14.01	13.58	14.04	14.61	15.37	15.36	15.34	15.35
32	**Secondary Sales**								
33	Customers (average during year)	22	21	21	14	2	0	0	0
34	Sales in MWh	18,053	16,843	10,153	552	1,993	0	0	0
35	MWh sales per customer	821	802	483	39	997	-	-	-
36	Revenue ($000s)	1,389	1,092	665	41	164	0	0	0
37	Cents per KWh	7.69	6.48	6.55	7.43	8.23	-	-	-
38	**Wholesale Sales**								
39	Customers (average during year)	2	2	2	2	2	2	2	2
40	Sales in MWh	412	360	365	427	338	338	338	338
41	MWh sales per customer	206	180	183	214	169	169	169	169
42	Revenue ($000s)	41	37	38	38	28	28	28	28
43	Cents per KWh	9.95	10.28	10.41	8.90	8.30	8.30	8.30	8.30
44	**Total Company**								
45	Customers	15,339	15,596	15,885	16,272	16,703	17,028	17,306	17,597
46	Sales in MWh	292,647	293,917	291,808	297,445	316,575	318,999	328,768	334,917
47	Revenue ($000s)	39,834	38,699	40,202	43,405	48,486	48,959	50,421	51,391
48	Cents/KWh	13.61	13.17	13.78	14.59	15.32	15.35	15.34	15.34
49	Total Revenues	39,834	38,699	40,202	43,405	48,486	48,959	50,421	51,391

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Hydro Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	11,701	11,921	12,146	12,456	12,834	13,143	13,368	13,596
3	Sales in MWh	119,640	121,938	122,732	132,820	141,284	143,018	145,460	147,947
4	MWh sales per customer	10.2	10.2	10.1	10.7	11.0	10.9	10.9	10.9
5	Revenue ($000s)	15,495	15,171	15,722	17,670	19,792	20,005	20,346	20,694
6	Cents per KWh	12.95	12.44	12.81	13.30	14.01	13.99	13.99	13.99
7	**Commercial**								
8	Customers (average during year)	2,253	2,288	2,346	2,415	2,483	2,525	2,557	2,597
9	Sales in MWh	132,077	132,624	136,223	141,006	149,182	151,698	154,915	158,215
10	MWh sales per customer	58.6	58.0	58.1	58.4	60.1	60.1	60.6	60.9
11	Revenue ($000s)	19,187	18,838	20,030	21,749	24,283	24,729	25,284	25,845
12	Cents per KWh	14.53	14.20	14.70	15.42	16.28	16.30	16.32	16.34
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	1	1	1
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	1,025	4,620	4,620
16	MWh sales per customer						1,025	4,620	4,620
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	143	612	612
18	Cents per KWh						13.91	13.26	13.26
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	13,954	14,209	14,492	14,871	15,318	15,668	15,925	16,193
21	Sales in MWh	251,717	254,561	258,955	273,827	290,466	295,741	304,995	310,781
22	Revenue ($000s)	34,683	34,009	35,752	39,418	44,076	44,876	46,242	47,152
23	Cents/KWh	13.78	13.36	13.81	14.40	15.17	15.17	15.16	15.17
24	**Secondary Sales**								
25	Customers (average during year)	22	21	21	14	2	-	-	-
26	Sales in MWh	18,053	16,843	10,153	552	1,993	-	-	-
27	MWh sales per customer	820.6	802	483	39	997	-	-	-
28	Revenue ($000s)	1,389	1,092	665	41	164.1	-	-	-
29	Cents per KWh	7.69	6.48	6.55	7.43	8.23	-	-	-
30	**Wholesale Sales**								
31	Customers (average during year)	2	2	2	2	2	2	2	2
32	Sales in MWh	412	360	365	427	338	338	338	338
33	MWh sales per customer	206	180	183	214	169	169	169	169
34	Revenue ($000s)	41	37	38	38	28	28	28	28
35	Cents per KWh	9.95	10.28	10.41	8.90	8.30	8.30	8.30	8.30
36	**Total Company (Excluding Lights)**								
37	Customers	13,978	14,232	14,515	14,887	15,322	15,670	15,927	16,195
38	Sales in MWh	270,182	271,764	269,473	274,806	292,797	296,079	305,333	311,120
39	Revenue ($000s)	36,113	35,138	36,455	39,497	44,268	44,904	46,271	47,180
40	Cents/KWh	13.37	12.93	13.53	14.37	15.12	15.17	15.15	15.16
41	Total Revenues	36,113	35,138	36,455	39,497	44,268	44,904	46,271	47,180

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Large Diesel Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	710	716	719	719	712	703	715	727
3	Sales in MWh	6,493	6,445	6,352	6,496	6,617	6,345	6,454	6,567
4	MWh sales per customer	9.1	9.0	8.8	9.0	9.3	9.0	9.0	9.0
5	Revenue ($000s)	847	814	838	886	952	914	929	946
6	Cents per KWh	13.05	12.64	13.19	13.63	14.38	14.40	14.40	14.40
7	**Commercial**								
8	Customers (average during year)	201	199	201	208	209	202	204	207
9	Sales in MWh	6,597	6,562	6,681	6,537	7,287	7,030	7,300	7,408
10	MWh sales per customer	32.8	32.9	33.3	31.4	34.8	34.9	35.8	35.8
11	Revenue ($000s)	1,023	962	1,010	1,055	1,227	1,173	1,228	1,246
12	Cents per KWh	15.51	14.66	15.12	16.14	16.83	16.69	16.82	16.81
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	911	915	920	927	922	904	918	934
21	Sales in MWh	13,090	13,006	13,033	13,033	13,904	13,376	13,754	13,974
22	Revenue ($000s)	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191
23	Cents/KWh	14.29	13.66	14.18	14.89	15.67	15.60	15.68	15.68
24	**Total Company (Excluding Lights)**								
25	Customers	911	915	920	927	922	904	918	934
26	Sales in MWh	13,090	13,006	13,033	13,033	13,904	13,376	13,754	13,974
27	Revenue ($000s)	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191
28	Cents/KWh	14.29	13.66	14.18	14.89	15.67	15.60	15.68	15.68
29	Total Revenues	1,870	1,777	1,848	1,941	2,178	2,087	2,157	2,191

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Small Diesel Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	167	166	165	168	169	170	172	176
3	Sales in MWh	1,242	1,212	1,210	1,290	1,373	1,337	1,360	1,383
4	MWh sales per customer	7.4	7.3	7.4	7.7	8.1	7.9	7.9	7.9
5	Revenue ($000s)	184	172	178	193	211	204	207	211
6	Cents per KWh	14.78	14.20	14.71	14.99	15.38	15.25	15.24	15.25
7	**Commercial**								
8	Customers (average during year)	109	107	109	111	108	99	100	102
9	Sales in MWh	2,266	2,119	2,135	2,222	2,191	1,956	1,987	2,020
10	MWh sales per customer	20.8	19.8	19.6	20.1	20.2	19.8	19.8	19.8
11	Revenue ($000s)	401	369	385	389	384	345	351	357
12	Cents per KWh	17.68	17.39	18.02	17.51	17.55	17.66	17.66	17.66
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	276	273	273	279	278	269	273	278
21	Sales in MWh	3,507	3,331	3,345	3,513	3,563	3,293	3,346	3,403
22	Revenue ($000s)	584	541	563	582	596	549	558	568
23	Cents/KWh	16.65	16.23	16.82	16.58	16.72	16.68	16.68	16.68
24	**Total Company (Excluding Lights)**								
25	Customers	276	273	273	279	278	269	273	278
26	Sales in MWh	3,507	3,331	3,345	3,513	3,563	3,293	3,346	3,403
27	Revenue ($000s)	584	541	563	582	596	549	558	568
28	Cents/KWh	16.65	16.23	16.82	16.58	16.72	16.68	16.68	16.68
29	Total Revenues	584	541	563	582	596	549	558	568

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Summary of Customers, Energy Sales and Revenue - Old Crow Rate Zone

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period Existing 2013	Existing 2014	Existing 2015
1	**Residential**								
2	Customers (average during year)	137	140	139	140	142	144	146	148
3	Sales in MWh	928	975	979	1,089	1,076	1,092	1,107	1,126
4	MWh sales per customer	6.7	6.9	7.0	7.8	7.6	7.6	7.6	7.6
5	Revenue ($000s)	145	149	155	179	171	172	174	177
6	Cents per KWh	15.65	15.33	15.80	16.46	15.93	15.72	15.72	15.72
7	**Commercial**								
8	Customers (average during year)	37	35	37	40	40	42	42	42
9	Sales in MWh	765	772	737	826	903	881	893	906
10	MWh sales per customer	20.8	21.8	20.0	20.6	22.3	21.0	21.3	21.6
11	Revenue ($000s)	207	199	196	181	163	150	152	155
12	Cents per KWh	27.08	25.76	26.62	21.95	18.02	17.06	17.06	17.06
13	**Industrial**								
14	Customers (average during year)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Sales in MWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	MWh sales per customer								
17	Revenue ($000s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Cents per KWh								
19	**Total Company - Retail - Primary (Excluding Lights)**								
20	Customers	174	176	176	180	182	186	188	190
21	Sales in MWh	1,692	1,747	1,716	1,915	1,978	1,973	2,000	2,032
22	Revenue ($000s)	352	348	351	360	334	322	326	332
23	Cents/KWh	20.82	19.94	20.45	18.83	16.88	16.32	16.32	16.31
24	**Total Company (Excluding Lights)**								
25	Customers	174	176	176	180	182	186	188	190
26	Sales in MWh	1,692	1,747	1,716	1,915	1,978	1,973	2,000	2,032
27	Revenue ($000s)	352	348	351	360	334	322	326	332
28	Cents/KWh	20.82	19.94	20.45	18.83	16.88	16.32	16.32	16.31
29	Total Revenues	352	348	351	360	334	322	326	332

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	
Jan-08	9,449	12,269,006	1,298		1,114	1,287		
Feb-08	9,442	11,196,255	1,186		955	1,121		
Mar-08	9,455	9,563,985	1,012		735	1,039		
Apr-08	9,457	8,909,635	942		517	929		
May-08	9,460	7,459,428	789		308	796		
Jun-08	9,482	6,603,909	696		226	662		
Jul-08	9,482	6,456,565	681		173	648		
Aug-08	9,497	6,657,098	701		188	689		
Sep-08	9,528	6,675,999	701		319	699		
Oct-08	9,584	7,021,661	733		563	721		
Nov-08	9,563	9,417,742	985		783	1,003		
Dec-08	9,605	9,714,521	1,011	10,734	1,186	895		
Jan-09	9,619	14,703,140	1,529		1,138	1,504		
Feb-09	9,659	10,841,086	1,122		955	1,057		
Mar-09	9,687	10,593,111	1,094		869	1,049		
Apr-09	9,672	9,145,387	946		515	934		
May-09	9,682	7,485,113	773		331	768		
Jun-09	9,688	6,821,759	704		144	713		
Jul-09	9,704	6,817,908	703		63	730		
Aug-09	9,701	6,086,861	627		158	632		
Sep-09	9,714	6,991,253	720		306	725		
Oct-09	9,752	7,526,949	772		542	771		
Nov-09	9,773	9,319,856	954		782	973		
Dec-09	9,800	9,929,465	1,013	10,956	943	1,027	10,883	
Jan-10	9,815	13,210,358	1,346		991	1,401		
Feb-10	9,830	9,953,362	1,013		679	1,096		
Mar-10	9,830	9,242,694	940		656	1,010		
Apr-10	9,856	9,312,994	945		461	962		
May-10	9,849	7,831,404	795		292	811		
Jun-10	9,872	7,099,873	719		172	713		
Jul-10	9,891	6,781,330	686		117	683		
Aug-10	9,917	6,224,498	628		146	638		
Sep-10	9,914	7,144,977	721		332	711		
Oct-10	9,991	8,210,934	822		520	833		
Nov-10	10,030	9,069,490	904		718	958		
Dec-10	10,079	10,654,621	1,057	10,575	1,163	953	10,770	
Jan-11	10,094	14,500,257	1,437		1,010	1,481		
Feb-11	10,111	11,420,279	1,129		906	1,091		
Mar-11	10,111	12,700,787	1,256		902	1,193		
Apr-11	10,121	9,667,317	955		511	945		
May-11	10,130	9,045,994	893		296	907		
Jun-11	10,144	7,545,550	744		161	744		
Jul-11	10,164	6,885,882	677		128	670		
Aug-11	10,185	6,599,184	648		218	620		
Sep-11	10,201	7,524,695	738		329	731		
Nov-11	10,259	8,532,929	832		513	847		
Nov-11	10,340	9,756,743	944		936	879		
Dec-11	10,354	11,771,653	1,137	11,389	775	1,242	11,349	
Jan-12	10,393	14,103,108	1,357		1,118	1,343		
Feb-12	10,418	12,194,394	1,171		708	1,239		
Mar-12	10,441	11,466,512	1,098		756	1,114		
Apr-12	10,454	9,727,127	930		451	953		
May-12	10,476	8,747,823	835		351	820		
Jun-12	10,464	8,059,446	770		200	749		
Jul-12	10,529	7,464,066	709		140	694		
Aug-12	10,558	7,152,176	677		158	682		
Sep-12	10,586	7,358,794	695		287	710		
Oct-12	10,619	8,523,254	803		631	754		
Nov-12	10,643	10,766,338	1,012		970	929		
Dec-12	10,715	13,530,468	1,263	11,320	1,197	1,141	11,128	0.7%
2013-F							11,211	
2014-F							11,211	
2015-F							11,211	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Carmacks Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	205	270,973	1,322		1,114	1,308	
Feb-08	206	360,272	1,749		955	1,669	
Mar-08	205	233,748	1,140		735	1,174	
Apr-08	203	177,314	873		517	857	
May-08	201	166,776	830		308	839	
Jun-08	210	149,015	710		226	667	
Jul-08	214	111,763	522		173	482	
Aug-08	217	149,074	687		188	673	
Sep-08	214	161,163	753		319	751	
Oct-08	217	178,995	825		563	810	
Nov-08	217	252,048	1,162		783	1,184	
Dec-08	212	231,535	1,092	11,665	1,186	949	
Jan-09	212	332,633	1,569		1,138	1,539	
Feb-09	217	268,232	1,236		955	1,156	
Mar-09	215	239,361	1,113		869	1,058	
Apr-09	213	212,235	996		515	982	
May-09	215	131,596	612		331	606	
Jun-09	215	122,920	572		144	583	
Jul-09	214	142,635	667		63	700	
Aug-09	210	125,620	598		158	603	
Sep-09	211	173,478	822		306	828	
Oct-09	213	173,164	813		542	813	
Nov-09	215	216,604	1,007		782	1,031	
Dec-09	216	234,408	1,085	11,091	943	1,103	
Jan-10	215	348,960	1,623		991	1,690	
Feb-10	214	220,292	1,029		679	1,132	
Mar-10	210	217,282	1,035		656	1,120	
Apr-10	208	212,864	1,023		461	1,044	
May-10	205	164,059	800		292	820	
Jun-10	208	117,689	566		172	558	
Jul-10	208	149,087	717		117	714	
Aug-10	207	139,344	673		146	686	
Sep-10	198	146,065	738		332	726	
Oct-10	204	176,915	867		520	881	
Nov-10	206	198,627	964		718	1,030	
Dec-10	204	219,265	1,075	11,111	1,163	947	11,350
Jan-11	204	330,275	1,619		1,010	1,673	
Feb-11	205	269,535	1,315		906	1,268	
Mar-11	205	251,463	1,227		902	1,150	
Apr-11	203	185,553	914		511	902	
May-11	204	179,502	880		296	897	
Jun-11	206	123,143	598		161	598	
Jul-11	204	138,322	678		128	668	
Aug-11	203	140,788	694		218	659	
Sep-11	205	172,792	843		329	834	
Nov-11	204	170,508	836		513	854	
Nov-11	208	229,421	1,103		936	1,024	
Dec-11	202	214,597	1,062	11,768	775	1,191	11,718
Jan-12	210	357,637	1,703		1,118	1,686	
Feb-12	211	251,282	1,191		708	1,275	
Mar-12	210	304,478	1,450		756	1,469	
Apr-12	212	146,362	690		451	718	
May-12	214	172,110	804		351	785	
Jun-12	210	158,825	756		200	730	
Jul-12	210	118,436	564		140	546	
Aug-12	210	159,385	759		158	764	
Sep-12	209	137,669	659		287	677	
Oct-12	210	168,280	801		631	742	
Nov-12	209	288,888	1,382		970	1,281	
Dec-12	213	274,853	1,290	12,050	1,197	1,140	11,815
2013-F							11,628
2014-F							11,628
2015-F							11,628

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Carcross Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	232	191,192	824		1,114	817	
Feb-08	233	223,919	961		955	922	
Mar-08	233	169,312	727		735	743	
Apr-08	232	159,486	687		517	680	
May-08	234	143,833	615		308	619	
Jun-08	236	116,358	493		226	472	
Jul-08	234	106,910	457		173	437	
Aug-08	237	120,069	507		188	500	
Sep-08	238	107,891	453		319	452	
Oct-08	235	116,583	496		563	489	
Nov-08	234	145,852	623		783	634	
Dec-08	235	170,315	725	7,568	1,186	655	
Jan-09	235	213,697	909		1,138	895	
Feb-09	237	211,727	893		955	854	
Mar-09	238	196,424	825		869	798	
Apr-09	238	181,815	764		515	757	
May-09	242	168,472	696		331	693	
Jun-09	243	125,606	517		144	522	
Jul-09	241	119,894	497		63	514	
Aug-09	242	106,627	441		158	443	
Sep-09	243	115,139	474		306	477	
Oct-09	245	137,384	561		542	561	
Nov-09	245	151,216	617		782	629	
Dec-09	245	182,836	746	7,941	943	755	
Jan-10	246	233,984	951		991	984	
Feb-10	248	229,357	925		679	975	
Mar-10	247	182,926	741		656	782	
Apr-10	247	166,931	676		461	686	
May-10	250	162,417	650		292	659	
Jun-10	251	133,093	530		172	527	
Jul-10	252	121,283	481		117	480	
Aug-10	252	115,715	459		146	466	
Sep-10	253	114,880	454		332	449	
Oct-10	251	144,645	576		520	583	
Nov-10	247	156,257	633		718	665	
Dec-10	247	170,916	692	7,768	1,163	630	7,885
Jan-11	247	256,402	1,038		1,010	1,065	
Feb-11	247	215,796	874		906	851	
Mar-11	248	230,708	930		902	893	
Apr-11	247	196,629	796		511	790	
May-11	253	148,572	587		296	596	
Jun-11	253	141,763	560		161	560	
Jul-11	253	115,593	457		128	452	
Aug-11	254	111,408	439		218	422	
Sep-11	252	130,273	517		329	513	
Nov-11	254	135,012	532		513	541	
Nov-11	252	155,215	616		936	577	
Dec-11	248	208,108	839	8,185	775	902	8,161
Jan-12	248	211,267	852		1,118	844	
Feb-12	248	252,902	1,020		708	1,061	
Mar-12	246	175,078	712		756	721	
Apr-12	248	169,800	685		451	698	
May-12	253	157,473	622		351	613	
Jun-12	253	137,494	543		200	531	
Jul-12	258	125,004	485		140	476	
Aug-12	257	131,406	511		158	514	
Sep-12	257	133,576	520		287	529	
Oct-12	254	132,319	521		631	492	
Nov-12	254	178,927	704		970	655	
Dec-12	251	205,670	819	7,994	1,197	746	7,879
2013-F							7,975
2014-F							7,975
2015-F							7,975

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Haines Junction Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	350	319,505	913		1,114	906	
Feb-08	352	298,048	847		955	809	
Mar-08	351	296,071	844		735	859	
Apr-08	351	235,359	671		517	663	
May-08	352	198,445	564		308	568	
Jun-08	354	184,683	522		226	501	
Jul-08	355	214,252	604		173	585	
Aug-08	355	187,109	527		188	520	
Sep-08	357	209,500	587		319	586	
Oct-08	355	184,518	520		563	513	
Nov-08	354	236,787	669		783	680	
Dec-08	354	268,108	757	8,023	1,186	689	
Jan-09	353	360,678	1,022		1,138	1,007	
Feb-09	352	257,154	731		955	693	
Mar-09	354	279,480	789		869	763	
Apr-09	352	225,364	640		515	633	
May-09	355	242,603	683		331	681	
Jun-09	356	195,099	548		144	553	
Jul-09	357	191,008	535		63	551	
Aug-09	359	182,361	508		158	510	
Sep-09	360	191,567	532		306	535	
Oct-09	358	206,898	578		542	578	
Nov-09	354	261,275	738		782	749	
Dec-09	358	250,902	701	8,005	943	709	
Jan-10	358	344,355	962		991	994	
Feb-10	359	256,515	715		679	763	
Mar-10	357	254,521	713		656	754	
Apr-10	360	219,524	610		461	620	
May-10	362	222,984	616		292	625	
Jun-10	363	209,884	578		172	575	
Jul-10	365	189,107	518		117	517	
Aug-10	369	180,314	489		146	495	
Sep-10	374	205,556	550		332	544	
Oct-10	372	212,879	572		520	579	
Nov-10	379	258,172	681		718	712	
Dec-10	378	268,489	710	7,713	1,163	650	7,827
Jan-11	378	377,850	1,000		1,010	1,025	
Feb-11	378	284,896	754		906	731	
Mar-11	378	292,208	773		902	736	
Apr-11	377	248,458	659		511	653	
May-11	379	252,259	666		296	674	
Jun-11	380	205,592	541		161	541	
Jul-11	383	205,103	536		128	531	
Aug-11	384	179,161	467		218	450	
Sep-11	384	198,252	516		329	512	
Nov-11	377	226,437	601		513	609	
Nov-11	383	261,152	682		936	644	
Dec-11	381	280,279	736	7,928	775	797	7,905
Jan-12	380	352,775	928		1,118	920	
Feb-12	383	314,667	822		708	861	
Mar-12	383	279,649	730		756	739	
Apr-12	382	250,547	656		451	669	
May-12	382	209,418	548		351	539	
Jun-12	384	230,104	599		200	587	
Jul-12	389	209,114	538		140	529	
Aug-12	389	167,224	430		158	432	
Sep-12	382	214,105	560		287	569	
Oct-12	388	221,577	571		631	543	
Nov-12	389	260,807	670		970	623	
Dec-12	386	349,387	905	7,958	1,197	834	7,846
2013-F							7,859
2014-F							7,859
2015-F							7,859

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Teslin Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	245	216,414	883		1,114	877	
Feb-08	247	232,931	943		955	908	
Mar-08	247	133,656	541		735	556	
Apr-08	249	135,849	546		517	538	
May-08	248	139,678	563		308	567	
Jun-08	252	105,137	417		226	398	
Jul-08	252	107,041	425		173	407	
Aug-08	249	132,160	531		188	524	
Sep-08	255	121,672	477		319	476	
Oct-08	258	155,094	601		563	595	
Nov-08	250	141,390	566		783	576	
Dec-08	252	161,590	641	7,134	1,186	577	
Jan-09	248	256,107	1,033		1,138	1,019	
Feb-09	224	205,093	916		955	880	
Mar-09	251	126,666	505		869	480	
Apr-09	254	137,937	543		515	537	
May-09	261	157,391	603		331	600	
Jun-09	263	110,039	418		144	423	
Jul-09	261	133,886	513		63	528	
Aug-09	263	112,418	427		158	430	
Sep-09	261	114,865	440		306	443	
Oct-09	261	146,569	562		542	561	
Nov-09	260	148,117	570		782	580	
Dec-09	258	170,066	659	7,188	943	667	
Jan-10	259	230,825	891		991	921	
Feb-10	259	166,034	641		679	687	
Mar-10	259	157,520	608		656	646	
Apr-10	259	168,540	651		461	660	
May-10	262	128,723	491		292	500	
Jun-10	262	120,573	460		172	457	
Jul-10	264	140,333	532		117	530	
Aug-10	263	101,789	387		146	393	
Sep-10	260	136,821	526		332	521	
Oct-10	263	143,157	544		520	550	
Nov-10	259	160,001	618		718	647	
Dec-10	261	204,972	785	7,135	1,163	728	7,242
Jan-11	260	223,209	858		1,010	883	
Feb-11	261	170,699	654		906	633	
Mar-11	260	213,994	823		902	789	
Apr-11	262	145,282	555		511	549	
May-11	259	159,685	617		296	624	
Jun-11	261	119,076	456		161	456	
Jul-11	264	134,793	511		128	506	
Aug-11	266	115,533	434		218	419	
Sep-11	267	142,094	532		329	528	
Nov-11	266	141,620	532		513	541	
Nov-11	267	159,981	599		936	564	
Dec-11	270	192,094	711	7,283	775	769	7,261
Jan-12	269	257,188	956		1,118	949	
Feb-12	269	181,756	676		708	713	
Mar-12	270	197,921	733		756	742	
Apr-12	272	157,130	578		451	590	
May-12	273	139,405	511		351	502	
Jun-12	273	136,904	501		200	490	
Jul-12	274	116,270	424		140	416	
Aug-12	276	107,721	390		158	393	
Sep-12	276	139,131	504		287	512	
Oct-12	279	138,414	496		631	469	
Nov-12	277	206,220	744		970	699	
Dec-12	277	215,033	776	7,290	1,197	709	7,185
2013-F							7,229
2014-F							7,229
2015-F							7,229

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Ross River Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	164	138,428	844		1,114	835	
Feb-08	166	180,188	1,085		955	1,034	
Mar-08	162	112,138	692		735	714	
Apr-08	167	101,559	608		517	598	
May-08	167	108,911	652		308	658	
Jun-08	168	83,087	495		226	467	
Jul-08	166	84,046	506		173	481	
Aug-08	167	88,077	527		188	518	
Sep-08	165	94,219	571		319	570	
Oct-08	166	92,484	557		563	548	
Nov-08	163	131,936	809		783	824	
Dec-08	164	125,781	767	8,115	1,186	675	
Jan-09	161	203,764	1,266		1,138	1,246	
Feb-09	165	132,362	802		955	751	
Mar-09	166	133,723	806		869	770	
Apr-09	167	114,214	684		515	674	
May-09	167	113,208	678		331	674	
Jun-09	165	93,976	570		144	577	
Jul-09	165	98,285	596		63	617	
Aug-09	164	88,391	539		158	542	
Sep-09	163	70,475	432		306	436	
Oct-09	164	115,117	702		542	702	
Nov-09	163	101,087	620		782	635	
Dec-09	163	138,640	851	8,544	943	862	
Jan-10	163	172,030	1,055		991	1,099	
Feb-10	165	127,134	771		679	837	
Mar-10	166	109,653	661		656	716	
Apr-10	168	125,996	750		461	764	
May-10	170	93,843	552		292	565	
Jun-10	169	88,991	527		172	522	
Jul-10	170	95,885	564		117	562	
Aug-10	168	80,787	481		146	489	
Sep-10	168	101,528	604		332	597	
Oct-10	165	96,733	586		520	595	
Nov-10	169	111,109	657		718	700	
Dec-10	169	161,797	957	8,165	1,163	875	8,320
Jan-11	170	186,091	1,095		1,010	1,130	
Feb-11	169	161,456	955		906	925	
Mar-11	170	162,357	955		902	905	
Apr-11	170	150,596	886		511	878	
May-11	173	112,717	652		296	663	
Jun-11	173	93,659	541		161	541	
Jul-11	171	96,055	562		128	555	
Aug-11	171	85,304	499		218	477	
Sep-11	169	105,303	623		329	617	
Nov-11	166	99,082	597		513	609	
Nov-11	168	107,996	643		936	592	
Dec-11	169	163,134	965	8,973	775	1,048	8,941
Jan-12	170	185,667	1,092		1,118	1,081	
Feb-12	170	166,679	980		708	1,035	
Mar-12	169	164,487	973		756	986	
Apr-12	169	120,116	711		451	729	
May-12	171	100,221	586		351	574	
Jun-12	169	108,363	641		200	624	
Jul-12	171	86,096	503		140	492	
Aug-12	174	91,515	526		158	529	
Sep-12	175	88,707	507		287	519	
Oct-12	179	100,177	560		631	521	
Nov-12	179	161,940	905		970	840	
Dec-12	178	175,254	985	8,969	1,197	888	8,817
2013-F							8,693
2014-F							8,693
2015-F							8,693

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Pelly Crossing Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	143	163,373	1,142		1,114	1,133	
Feb-08	144	185,324	1,287		955	1,349	
Mar-08	143	137,039	958		735	1,119	
Apr-08	142	81,727	576		517	834	
May-08	142	115,067	810		308	1,163	
Jun-08	143	86,991	608		226	998	
Jul-08	142	62,541	440		173	853	
Aug-08	141	87,862	623		188	1,030	
Sep-08	146	82,902	568		319	916	
Oct-08	146	107,401	736		563	974	
Nov-08	143	115,441	807		783	947	
Dec-08	145	128,250	884	9,441	1,186	842	
Jan-09	145	195,702	1,350		1,138	1,329	
Feb-09	146	150,422	1,030		955	976	
Mar-09	144	144,810	1,006		869	968	
Apr-09	145	100,376	692		515	682	
May-09	147	105,215	716		331	712	
Jun-09	148	80,962	547		144	555	
Jul-09	144	87,258	606		63	629	
Aug-09	144	76,992	535		158	538	
Sep-09	140	86,693	619		306	623	
Oct-09	144	121,044	841		542	840	
Nov-09	146	126,109	864		782	880	
Dec-09	144	133,097	924	9,729	943	936	
Jan-10	144	140,084	973		991	1,018	
Feb-10	143	118,028	825		679	895	
Mar-10	144	111,916	777		656	835	
Apr-10	142	117,096	825		461	839	
May-10	144	98,003	681		292	694	
Jun-10	145	79,965	551		172	546	
Jul-10	143	107,477	752		117	750	
Aug-10	146	75,911	520		146	529	
Sep-10	135	93,466	692		332	685	
Oct-10	141	97,842	694		520	703	
Nov-10	145	112,197	774		718	818	
Dec-10	145	121,245	836	8,900	1,163	750	9,063
Jan-11	145	181,367	1,251		1,010	1,288	
Feb-11	143	132,146	924		906	892	
Mar-11	147	133,068	905		902	853	
Apr-11	146	110,951	760		511	752	
May-11	144	110,139	765		296	776	
Jun-11	140	76,274	545		161	545	
Jul-11	144	92,521	643		128	636	
Aug-11	146	86,654	594		218	570	
Sep-11	146	104,289	714		329	708	
Nov-11	146	98,979	678		513	690	
Nov-11	148	131,772	890		936	837	
Dec-11	144	135,715	942	9,611	775	1,030	9,577
Jan-12	147	193,513	1,316		1,118	1,305	
Feb-12	146	131,098	898		708	955	
Mar-12	148	160,054	1,081		756	1,094	
Apr-12	148	88,485	598		451	617	
May-12	147	103,229	702		351	689	
Jun-12	145	115,883	799		200	782	
Jul-12	148	65,728	444		140	432	
Aug-12	148	96,215	650		158	654	
Sep-12	148	93,744	633		287	646	
Oct-12	151	109,385	724		631	684	
Nov-12	151	175,449	1,162		970	1,093	
Dec-12	153	173,786	1,136	10,145	1,197	1,034	9,985
2013-F							9,542
2014-F							9,542
2015-F							9,542

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Old Crow Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	131	91,080	695		1,114	689	
Feb-08	131	104,191	795		955	763	
Mar-08	128	75,158	587		735	601	
Apr-08	134	76,598	572		517	565	
May-08	138	75,835	550		308	553	
Jun-08	139	77,827	560		226	542	
Jul-08	142	56,734	400		173	383	
Aug-08	143	76,254	533		188	527	
Sep-08	143	64,023	448		319	447	
Oct-08	140	57,323	409		563	403	
Nov-08	141	89,395	634		783	643	
Dec-08	139	77,918	561	6,743	1,186	502	
Jan-09	139	119,647	861		1,138	848	
Feb-09	136	87,509	643		955	611	
Mar-09	139	89,694	645		869	623	
Apr-09	141	91,451	649		515	643	
May-09	141	83,798	594		331	592	
Jun-09	144	71,199	494		144	499	
Jul-09	144	74,912	520		63	534	
Aug-09	141	57,483	408		158	410	
Sep-09	142	60,469	426		306	428	
Oct-09	142	84,122	592		542	592	
Nov-09	138	87,918	637		782	647	
Dec-09	137	80,345	586	7,057	943	594	
Jan-10	137	111,757	816		991	843	
Feb-10	137	93,880	685		679	728	
Mar-10	138	87,449	634		656	669	
Apr-10	138	103,587	751		461	759	
May-10	139	67,465	485		292	494	
Jun-10	140	61,879	442		172	439	
Jul-10	140	70,851	506		117	505	
Aug-10	139	57,504	414		146	419	
Sep-10	141	66,581	472		332	468	
Oct-10	141	84,042	596		520	602	
Nov-10	143	81,156	568		718	595	
Dec-10	140	89,309	638	7,006	1,163	585	7,105
Jan-11	141	147,202	1,044		1,010	1,066	
Feb-11	139	106,269	765		906	745	
Mar-11	137	93,778	685		902	653	
Apr-11	138	121,063	877		511	872	
May-11	140	96,075	686		296	693	
Jun-11	140	64,261	459		161	459	
Jul-11	139	76,307	549		128	545	
Aug-11	141	64,040	454		218	440	
Sep-11	140	73,293	524		329	520	
Nov-11	142	72,107	508		513	515	
Nov-11	139	79,743	574		936	541	
Dec-11	140	113,678	812	7,936	775	865	7,915
Jan-12	140	110,225	787		1,118	780	
Feb-12	143	104,490	731		708	765	
Mar-12	142	118,638	835		756	843	
Apr-12	142	93,954	662		451	673	
May-12	142	80,480	567		351	559	
Jun-12	138	81,250	589		200	578	
Jul-12	140	60,953	435		140	428	
Aug-12	142	83,331	587		158	589	
Sep-12	142	48,796	344		287	351	
Oct-12	145	72,356	499		631	474	
Nov-12	142	91,731	646		970	604	
Dec-12	143	112,281	785	7,467	1,197	723	7,370
2013-F							7,463
2014-F							7,463
2015-F							7,463

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Destruction Bay Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	96	69,839	727		1,114	723	
Feb-08	96	53,911	562		955	535	
Mar-08	96	58,923	614		735	625	
Apr-08	95	55,343	583		517	577	
May-08	95	49,769	524		308	527	
Jun-08	96	49,553	516		226	502	
Jul-08	97	39,916	412		173	398	
Aug-08	97	42,410	437		188	432	
Sep-08	97	40,477	417		319	417	
Oct-08	99	38,346	387		563	383	
Nov-08	99	55,145	557		783	565	
Dec-08	99	54,626	552	6,288	1,186	504	
Jan-09	97	72,543	748		1,138	738	
Feb-09	98	61,817	631		955	604	
Mar-09	98	58,039	592		869	574	
Apr-09	98	60,358	616		515	611	
May-09	97	45,668	471		331	469	
Jun-09	93	40,017	430		144	434	
Jul-09	95	42,419	447		63	458	
Aug-09	96	35,939	374		158	376	
Sep-09	97	43,929	453		306	455	
Oct-09	95	42,179	444		542	444	
Nov-09	92	51,709	562		782	570	
Dec-09	92	52,117	566	6,334	943	572	
Jan-10	93	77,387	832		991	854	
Feb-10	93	55,867	601		679	635	
Mar-10	94	48,574	517		656	545	
Apr-10	94	57,930	616		461	623	
May-10	98	50,648	517		292	523	
Jun-10	97	40,963	422		172	420	
Jul-10	97	42,640	440		117	439	
Aug-10	100	30,270	303		146	307	
Sep-10	99	44,632	451		332	447	
Oct-10	98	48,411	494		520	499	
Nov-10	95	55,968	589		718	611	
Dec-10	95	56,187	591	6,373	1,163	549	6,452
Jan-11	95	71,097	748		1,010	767	
Feb-11	95	69,550	732		906	716	
Mar-11	95	62,307	656		902	630	
Apr-11	97	60,626	625		511	621	
May-11	98	47,666	486		296	492	
Jun-11	100	44,866	449		161	449	
Jul-11	99	39,981	404		128	401	
Aug-11	100	39,974	400		218	388	
Sep-11	97	46,103	475		329	472	
Nov-11	98	49,678	507		513	513	
Nov-11	98	51,295	523		936	497	
Dec-11	97	70,724	729	6,735	775	772	6,718
Jan-12	98	81,478	831		1,118	826	
Feb-12	97	66,408	685		708	713	
Mar-12	97	67,243	693		756	700	
Apr-12	97	49,038	506		451	515	
May-12	96	43,666	455		351	449	
Jun-12	94	51,763	551		200	542	
Jul-12	95	41,417	436		140	430	
Aug-12	96	44,073	459		158	461	
Sep-12	94	41,900	446		287	452	
Oct-12	97	47,157	486		631	466	
Nov-12	97	55,766	575		970	541	
Dec-12	95	75,934	799	6,921	1,197	749	6,843
2013-F							6,671
2014-F							6,671
2015-F							6,671

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Beaver Creek Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	67	63,422	947		1,114	938	
Feb-08	67	66,785	997		955	948	
Mar-08	67	48,089	718		735	738	
Apr-08	68	49,702	731		517	721	
May-08	68	43,227	636		308	641	
Jun-08	67	40,688	607		226	581	
Jul-08	68	38,326	564		173	539	
Aug-08	68	43,814	644		188	635	
Sep-08	67	35,662	532		319	531	
Oct-08	67	41,349	617		563	608	
Nov-08	66	50,959	772		783	786	
Dec-08	67	67,800	1,012	8,776	1,186	924	
Jan-09	67	63,353	946		1,138	927	
Feb-09	66	61,046	925		955	876	
Mar-09	66	55,035	834		869	800	
Apr-09	68	50,396	741		515	732	
May-09	68	39,722	584		331	580	
Jun-09	68	33,934	499		144	506	
Jul-09	67	40,837	610		63	630	
Aug-09	67	39,459	589		158	592	
Sep-09	67	39,571	591		306	594	
Oct-09	66	45,651	692		542	691	
Nov-09	67	52,749	787		782	802	
Dec-09	67	56,705	846	8,643	943	857	
Jan-10	67	73,461	1,096		991	1,138	
Feb-10	67	58,718	876		679	940	
Mar-10	65	53,024	816		656	868	
Apr-10	67	49,783	743		461	756	
May-10	67	46,506	694		292	706	
Jun-10	68	38,372	564		172	560	
Jul-10	67	40,978	612		117	610	
Aug-10	65	40,940	630		146	638	
Sep-10	66	37,510	568		332	561	
Oct-10	66	43,699	662		520	671	
Nov-10	66	44,720	678		718	718	
Dec-10	66	51,924	787	8,726	1,163	708	8,874
Jan-11	65	73,657	1,133		1,010	1,167	
Feb-11	67	58,086	867		906	838	
Mar-11	67	58,001	866		902	818	
Apr-11	68	49,251	724		511	717	
May-11	68	41,615	612		296	622	
Jun-11	69	36,805	533		161	533	
Jul-11	69	41,654	604		128	598	
Aug-11	69	41,815	606		218	585	
Sep-11	68	40,426	595		329	589	
Nov-11	68	45,834	674		513	685	
Nov-11	72	63,796	886		936	837	
Dec-11	71	74,507	1,049	9,149	775	1,129	9,119
Jan-12	71	78,077	1,100		1,118	1,089	
Feb-12	71	64,051	902		708	954	
Mar-12	71	61,206	862		756	874	
Apr-12	72	48,111	668		451	686	
May-12	72	46,435	645		351	633	
Jun-12	69	45,435	658		200	643	
Jul-12	71	39,794	560		140	549	
Aug-12	71	43,174	608		158	611	
Sep-12	71	42,305	596		287	607	
Oct-12	71	50,852	716		631	679	
Nov-12	72	62,837	873		970	811	
Dec-12	71	75,071	1,057	9,246	1,197	965	9,101
2013-F							9,031
2014-F							9,031
2015-F							9,031

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Tagish Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	328	173,641	529		1,114	524	
Feb-08	325	196,641	605		955	577	
Mar-08	326	134,643	413		735	425	
Apr-08	328	111,708	341		517	335	
May-08	333	96,449	290		308	293	
Jun-08	334	94,007	281		226	266	
Jul-08	336	90,493	269		173	255	
Aug-08	338	107,999	320		188	314	
Sep-08	338	99,082	293		319	292	
Oct-08	335	106,242	317		563	312	
Nov-08	328	160,587	490		783	498	
Dec-08	326	166,814	512	4,660	1,186	460	
Jan-09	322	221,788	689		1,138	678	
Feb-09	324	180,403	557		955	528	
Mar-09	303	148,681	491		869	471	
Apr-09	306	130,333	426		515	421	
May-09	339	98,861	292		331	289	
Jun-09	340	91,995	271		144	275	
Jul-09	333	107,399	323		63	335	
Aug-09	342	96,059	281		158	283	
Sep-09	341	103,660	304		306	306	
Oct-09	341	131,419	385		542	385	
Nov-09	329	148,515	451		782	460	
Dec-09	327	167,723	513	4,982	943	519	
Jan-10	328	207,053	631		991	655	
Feb-10	313	160,188	512		679	549	
Mar-10	321	136,527	425		656	456	
Apr-10	324	137,314	424		461	431	
May-10	334	117,245	351		292	358	
Jun-10	338	95,130	281		172	279	
Jul-10	343	108,576	317		117	316	
Aug-10	338	105,213	311		146	316	
Sep-10	324	108,883	336		332	332	
Oct-10	341	141,371	415		520	419	
Nov-10	334	139,277	417		718	441	
Dec-10	330	177,134	537	4,957	1,163	491	5,043
Jan-11	330	241,159	731		1,010	750	
Feb-11	328	170,902	521		906	504	
Mar-11	331	181,387	548		902	520	
Apr-11	332	130,345	393		511	388	
May-11	321	117,122	365		296	371	
Jun-11	342	97,953	286		161	286	
Jul-11	339	109,873	324		128	321	
Aug-11	343	108,934	318		218	305	
Sep-11	345	118,489	343		329	340	
Nov-11	343	124,107	362		513	368	
Nov-11	341	176,455	517		936	489	
Dec-11	333	164,591	494	5,202	775	540	5,185
Jan-12	332	232,663	701		1,118	695	
Feb-12	331	167,948	507		708	538	
Mar-12	335	169,143	505		756	512	
Apr-12	337	116,598	346		451	356	
May-12	338	118,998	352		351	345	
Jun-12	344	119,871	348		200	339	
Jul-12	348	109,618	315		140	309	
Aug-12	347	119,515	344		158	346	
Sep-12	346	115,503	334		287	340	
Oct-12	347	143,731	414		631	393	
Nov-12	344	176,497	513		970	477	
Dec-12	344	219,318	638	5,318	1,197	584	5,233
2013-F							5,154
2014-F							5,154
2015-F							5,154

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Marsh Lake Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	411	400,772	975		1,114	965	
Feb-08	410	391,831	956		955	899	
Mar-08	410	298,424	728		735	752	
Apr-08	412	271,266	658		517	647	
May-08	416	218,708	526		308	532	
Jun-08	419	204,232	487		226	457	
Jul-08	421	198,238	471		173	442	
Aug-08	420	233,573	556		188	546	
Sep-08	422	218,657	518		319	517	
Oct-08	419	248,762	594		563	583	
Nov-08	417	352,172	845		783	861	
Dec-08	413	443,500	1,074	8,387	1,186	971	
Jan-09	414	440,749	1,065		1,138	1,043	
Feb-09	411	377,505	919		955	861	
Mar-09	377	321,118	852		869	812	
Apr-09	407	311,581	766		515	755	
May-09	401	200,880	501		331	497	
Jun-09	420	207,457	494		144	502	
Jul-09	420	211,095	503		63	527	
Aug-09	425	200,538	472		158	475	
Sep-09	427	238,803	559		306	564	
Oct-09	428	261,931	612		542	612	
Nov-09	422	325,639	772		782	789	
Dec-09	416	417,792	1,004	8,517	943	1,017	
Jan-10	418	412,629	987		991	1,035	
Feb-10	411	333,347	811		679	885	
Mar-10	414	305,475	738		656	799	
Apr-10	424	300,073	708		461	723	
May-10	430	241,376	561		292	576	
Jun-10	426	201,491	473		172	468	
Jul-10	428	224,800	525		117	523	
Aug-10	423	210,803	498		146	508	
Sep-10	398	247,409	622		332	613	
Oct-10	430	288,653	671		520	681	
Nov-10	420	319,900	762		718	809	
Dec-10	422	418,397	991	8,348	1,163	900	8,520
Jan-11	419	533,507	1,273		1,010	1,312	
Feb-11	422	386,539	916		906	882	
Mar-11	422	395,398	937		902	882	
Apr-11	424	329,571	777		511	769	
May-11	427	258,919	606		296	619	
Jun-11	430	222,281	517		161	517	
Jul-11	432	211,742	490		128	483	
Aug-11	433	241,652	558		218	533	
Sep-11	434	253,323	584		329	577	
Nov-11	434	285,632	658		513	671	
Nov-11	433	378,486	874		936	817	
Dec-11	429	463,859	1,081	9,272	775	1,174	9,237
Jan-12	429	481,362	1,122		1,118	1,110	
Feb-12	427	418,969	981		708	1,042	
Mar-12	429	349,356	814		756	828	
Apr-12	429	271,112	632		451	652	
May-12	432	274,383	635		351	621	
Jun-12	430	226,538	527		200	508	
Jul-12	436	222,070	509		140	496	
Aug-12	431	251,460	583		158	587	
Sep-12	434	242,318	558		287	572	
Oct-12	435	305,434	702		631	659	
Nov-12	436	414,188	950		970	877	
Dec-12	433	560,428	1,294	9,309	1,197	1,186	9,140
2013-F							8,966
2014-F							8,966
2015-F							8,966

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Deep Creek Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	37	24,787	670		1,114	662	
Feb-08	38	24,484	644		955	601	
Mar-08	37	17,183	464		735	483	
Apr-08	37	15,980	432		517	423	
May-08	38	15,025	395		308	401	
Jun-08	39	11,658	299		226	275	
Jul-08	39	12,112	311		173	289	
Aug-08	40	14,232	356		188	348	
Sep-08	42	12,710	303		319	301	
Oct-08	40	11,303	283		563	275	
Nov-08	39	20,333	521		783	534	
Dec-08	40	20,697	517		1,186	439	
Jan-09	41	32,952	804		1,138	787	
Feb-09	41	18,170	443		955	399	
Mar-09	41	19,576	477		869	447	
Apr-09	42	11,396	271		515	263	
May-09	43	9,670	225		331	222	
Jun-09	42	11,584	276		144	282	
Jul-09	42	12,300	293		63	311	
Aug-09	42	11,644	277		158	280	
Sep-09	42	14,440	344		306	347	
Oct-09	42	14,789	352		542	352	
Nov-09	42	14,177	338		782	350	
Dec-09	42	14,316	341		943	350	
Jan-10	42	25,129	598		991	635	
Feb-10	41	15,883	387		679	444	
Mar-10	41	15,309	373		656	420	
Apr-10	41	17,914	437		461	449	
May-10	41	13,301	324		292	335	
Jun-10	43	12,054	280		172	276	
Jul-10	43	13,540	315		117	313	
Aug-10	42	12,057	287		146	294	
Sep-10	42	15,199	362		332	356	
Oct-10	42	16,102	383		520	391	
Nov-10	40	16,312	408		718	444	
Dec-10	41	19,783	483		1,163	412	4,770
Jan-11	41	28,824	703		1,010	733	
Feb-11	41	23,823	581		906	555	
Mar-11	40	29,345	734		902	691	
Apr-11	40	20,711	518		511	511	
May-11	41	16,103	393		296	402	
Jun-11	41	13,371	326		161	326	
Jul-11	40	11,214	280		128	275	
Aug-11	40	11,380	285		218	266	
Sep-11	40	15,078	377		329	372	
Nov-11	40	17,801	445		513	455	
Nov-11	41	20,634	503		936	460	
Dec-11	40	26,335	658		775	729	5,776
Jan-12	40	29,792	745		1,118	735	
Feb-12	40	30,462	762		708	808	
Mar-12	40	25,713	643		756	653	
Apr-12	40	21,670	542		451	557	
May-12	41	14,455	353		351	342	
Jun-12	41	12,317	300		200	286	
Jul-12	41	12,535	306		140	296	
Aug-12	41	15,324	374		158	377	
Sep-12	41	13,638	333		287	343	
Oct-12	40	14,883	372		631	339	
Nov-12	41	20,978	512		970	456	
Dec-12	40	27,516	688		1,197	605	5,798
2013-F							5,448
2014-F							5,448
2015-F							5,448

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Lower Post BC Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	69	78,905	1,144		1,300	1,125	
Feb-08	69	68,474	992		1,064	943	
Mar-08	68	53,857	792		833	790	
Apr-08	65	60,271	927		554	911	
May-08	68	44,158	649		296	650	
Jun-08	67	39,130	584		191	562	
Jul-08	66	37,269	565		132	549	
Aug-08	66	40,803	618		154	615	
Sep-08	65	37,607	579		304	574	
Oct-08	67	50,114	748		524	750	
Nov-08	66	54,570	827		879	825	
Dec-08	68	57,920	852	9,277	1,387	743	
Jan-09	68	91,464	1,345		1,329	1,316	
Feb-09	69	69,890	1,013		1,090	955	
Mar-09	70	67,233	960		1,054	881	
Apr-09	70	58,502	836		590	806	
May-09	70	44,936	642		356	622	
Jun-09	69	36,937	535		131	535	
Jul-09	70	44,160	631		89	630	
Aug-09	69	38,613	560		134	563	
Sep-09	69	46,655	676		279	680	
Oct-09	70	48,356	691		607	663	
Nov-09	70	55,125	788		997	745	
Dec-09	70	66,854	955	9,631	1,274	886	
Jan-10	70	86,749	1,239		1,141	1,276	
Feb-10	70	63,002	900		966	886	
Mar-10	64	49,267	770		764	793	
Apr-10	64	57,924	905		503	906	
May-10	64	46,119	721		278	728	
Jun-10	63	35,115	557		143	553	
Jul-10	64	32,961	515		71	521	
Aug-10	64	33,016	516		120	524	
Sep-10	65	38,150	587		320	577	
Oct-10	64	41,769	653		517	657	
Nov-10	62	47,559	767		904	757	
Dec-10	62	60,859	982	9,111	1,292	906	9,082
Jan-11	61	79,221	1,299		1,201	1,315	
Feb-11	62	53,257	859		1,005	831	
Mar-11	62	62,675	1,011		1,033	939	
Apr-11	61	44,109	723		588	695	
May-11	61	41,547	681		271	690	
Jun-11	61	37,373	613		143	608	
Jul-11	59	31,949	542		104	536	
Aug-11	59	34,837	590		195	573	
Sep-11	59	44,969	762		292	761	
Nov-11	61	39,770	652		512	658	
Nov-11	63	43,401	689		1,059	624	
Dec-11	63	56,750	901	9,321	1,006	925	9,155
Jan-12	63	74,774	1,187		1,273	1,178	
Feb-12	63	56,636	899		936	895	
Mar-12	63	55,930	888		909	859	
Apr-12	63	44,857	712		513	710	
May-12	62	42,971	693		340	678	
Jun-12	50	24,336	487		150	480	
Jul-12	63	37,116	589		78	592	
Aug-12	63	37,366	593		134	597	
Sep-12	63	22,846	363		259	373	
Oct-12	63	39,603	629		715	563	
Nov-12	56	43,671	780		1,113	696	
Dec-12	55	51,513	937	8,755	1,356	838	8,461
2013-F							8,899
2014-F							8,899
2015-F							8,899

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Upper Liard Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	64	65,667	1,026		1,300	1,010	
Feb-08	64	55,952	874		1,064	832	
Mar-08	63	41,649	661		833	660	
Apr-08	64	48,021	750		554	736	
May-08	65	29,073	447		296	448	
Jun-08	63	30,915	491		191	472	
Jul-08	63	34,030	540		132	527	
Aug-08	62	32,475	524		154	521	
Sep-08	63	35,568	565		304	560	
Oct-08	63	39,219	623		524	624	
Nov-08	63	39,430	626		879	625	
Dec-08	62	45,300	731	7,857	1,387	636	
Jan-09	62	71,230	1,149		1,329	1,124	
Feb-09	60	47,313	789		1,090	739	
Mar-09	61	52,291	857		1,054	789	
Apr-09	63	39,506	627		590	602	
May-09	64	44,628	697		356	680	
Jun-09	66	36,490	553		131	553	
Jul-09	66	31,727	481		89	480	
Aug-09	66	34,460	522		134	525	
Sep-09	66	34,956	530		279	533	
Oct-09	66	37,878	574		607	550	
Nov-09	65	45,540	701		997	664	
Dec-09	66	57,158	866	8,345	1,274	806	
Jan-10	66	68,432	1,037		1,141	1,069	
Feb-10	66	49,027	743		966	730	
Mar-10	66	50,961	772		764	792	
Apr-10	66	42,611	646		503	647	
May-10	66	35,222	534		278	540	
Jun-10	65	36,941	568		143	564	
Jul-10	66	32,762	496		71	501	
Aug-10	66	33,090	501		120	509	
Sep-10	63	33,518	532		320	523	
Oct-10	66	43,196	654		517	658	
Nov-10	66	42,270	640		904	632	
Dec-10	66	49,302	747	7,871	1,292	681	7,846
Jan-11	66	65,174	987		1,201	1,002	
Feb-11	65	47,235	727		1,005	702	
Mar-11	65	55,862	859		1,033	797	
Apr-11	65	39,282	604		588	580	
May-11	65	45,187	695		271	703	
Jun-11	64	31,926	499		143	495	
Jul-11	65	30,256	465		104	460	
Aug-11	65	34,251	527		195	511	
Sep-11	64	35,069	548		292	547	
Nov-11	65	39,130	602		512	607	
Nov-11	66	43,275	656		1,059	600	
Dec-11	66	47,885	726	7,896	1,006	747	7,752
Jan-12	66	65,790	997		1,273	989	
Feb-12	65	45,125	694		936	691	
Mar-12	66	47,560	721		909	696	
Apr-12	66	41,107	623		513	621	
May-12	66	38,426	582		340	569	
Jun-12	52	26,859	517		150	510	
Jul-12	63	29,214	464		78	467	
Aug-12	54	28,439	527		134	530	
Sep-12	53	28,120	531		259	540	
Oct-12	54	37,584	696		715	640	
Nov-12	54	40,378	748		1,113	676	
Dec-12	53	48,824	921	8,019	1,356	836	7,764
2013-F							7,787
2014-F							7,787
2015-F							7,787

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Watson Lake Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	Annual UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	577	648,227	1,123		1,300	1,105	
Feb-08	575	593,667	1,032		1,064	984	
Mar-08	576	480,732	835		833	833	
Apr-08	577	440,734	764		554	747	
May-08	583	400,179	686		296	687	
Jun-08	585	331,773	567		191	546	
Jul-08	584	344,932	591		132	575	
Aug-08	580	346,512	597		154	594	
Sep-08	585	346,036	592		304	587	
Oct-08	583	384,942	660		524	662	
Nov-08	575	483,711	841		879	840	
Dec-08	574	534,507	931	9,220	1,387	823	
Jan-09	581	663,093	1,141		1,329	1,113	
Feb-09	576	542,567	942		1,090	885	
Mar-09	576	499,062	866		1,054	788	
Apr-09	579	469,583	811		590	782	
May-09	589	389,486	661		356	641	
Jun-09	588	335,714	571		131	571	
Jul-09	580	348,504	601		89	600	
Aug-09	585	316,605	541		134	545	
Sep-09	583	362,886	622		279	626	
Oct-09	586	389,773	665		607	638	
Nov-09	584	455,989	781		997	738	
Dec-09	580	559,479	965	9,168	1,274	896	
Jan-10	579	632,709	1,093		1,141	1,130	
Feb-10	583	502,123	861		966	847	
Mar-10	587	458,172	781		764	803	
Apr-10	589	447,028	759		503	760	
May-10	590	382,172	648		278	655	
Jun-10	594	345,986	582		143	578	
Jul-10	588	335,565	571		71	576	
Aug-10	591	312,521	529		120	537	
Sep-10	590	359,939	610		320	600	
Oct-10	589	433,353	736		517	740	
Nov-10	595	443,539	745		904	735	
Dec-10	594	541,796	912	8,827	1,292	837	8,798
Jan-11	589	676,027	1,148		1,201	1,164	
Feb-11	591	523,769	886		1,005	858	
Mar-11	590	573,573	972		1,033	901	
Apr-11	592	490,322	828		588	800	
May-11	591	403,160	682		271	691	
Jun-11	594	364,889	614		143	610	
Jul-11	593	324,189	547		104	541	
Aug-11	594	336,216	566		195	548	
Sep-11	595	382,102	642		292	641	
Nov-11	594	397,049	668		512	674	
Nov-11	595	472,744	795		1,059	730	
Dec-11	593	548,323	925	9,273	1,006	949	9,108
Jan-12	594	667,785	1,124		1,273	1,115	
Feb-12	595	556,057	935		936	931	
Mar-12	594	514,187	866		909	837	
Apr-12	595	463,297	779		513	776	
May-12	590	419,114	710		340	696	
Jun-12	594	383,194	645		150	638	
Jul-12	589	346,701	589		78	592	
Aug-12	590	337,766	572		134	576	
Sep-12	590	332,985	564		259	575	
Oct-12	592	408,486	690		715	625	
Nov-12	595	460,221	773		1,113	691	
Dec-12	588	589,415	1,002	9,250	1,356	905	8,957
2013-F							8,954
2014-F							8,954
2015-F							8,954

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Keno City

Residential		**Energy (kWh)**		**(Whitehorse)**	**Annual**
monthly	**Customers**	**(Billed)**	**UPC (kWh)**	**MHDD**	**UPC (kWh)**
Jan-08	41	10,684	261	1,114	
Feb-08	41	12,628	308	955	
Mar-08	41	9,590	234	735	
Apr-08	40	12,167	304	517	
May-08	40	8,520	213	308	
Jun-08	41	5,939	145	226	
Jul-08	43	7,442	173	173	
Aug-08	42	11,599	276	188	
Sep-08	43	18,022	419	319	
Oct-08	43	17,099	398	563	
Nov-08	41	16,922	413	783	
Dec-08	40	23,060	577	1,186	
Jan-09	40	26,389	660	1,138	
Feb-09	40	11,784	295	955	
Mar-09	39	22,181	569	869	
Apr-09	41	13,250	323	515	
May-09	42	10,385	247	331	
Jun-09	42	7,458	178	144	
Jul-09	41	7,665	187	63	
Aug-09	42	7,579	180	158	
Sep-09	42	10,555	251	306	
Oct-09	41	12,095	295	542	
Nov-09	41	14,760	360	782	
Dec-09	41	15,725	384	943	
Jan-10	40	15,876	397	991	
Feb-10	39	12,949	332	679	
Mar-10	41	17,108	417	656	
Apr-10	39	13,401	344	461	
May-10	39	14,352	368	292	
Jun-10	40	5,109	128	172	
Jul-10	42	7,757	185	117	
Aug-10	42	8,430	201	146	
Sep-10	37	15,799	427	332	
Oct-10	37	16,490	446	520	
Nov-10	37	21,169	572	718	
Dec-10	37	21,264	575	1,163	4,390
Jan-11	37	21,762	588	1,010	
Feb-11	37	15,975	432	906	
Mar-11	37	22,527	609	902	
Apr-11	37	12,643	342	511	
May-11	39	13,354	342	296	
Jun-11	40	9,177	229	161	
Jul-11	40	13,430	336	128	
Aug-11	40	5,610	140	218	
Sep-11	40	13,729	343	329	
Nov-11	39	17,437	447	513	
Nov-11	39	18,395	472	936	
Dec-11	39	24,991	641	775	4,921
Jan-12	39	14,009	359	1,118	
Feb-12	39	15,827	406	708	
Mar-12	39	18,224	467	756	
Apr-12	39	15,467	397	451	
May-12	39	14,896	382	351	
Jun-12	40	11,732	293	200	
Jul-12	41	8,147	199	140	
Aug-12	41	9,042	221	158	
Sep-12	41	13,623	332	287	
Oct-12	41	18,789	458	631	
Nov-12	41	23,219	566	970	
Dec-12	41	19,709	481	1,197	4,561
2013-F					4,624
2014-F					4,624
2015-F					4,624

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Stewart Crossing

Residential		Energy (kWh)		(Watson Lake)	Annual
monthly	Customers	(Billed)	UPC (kWh)	MHDD	UPC (kWh)
Jan-08	16	17,369	1,086	1,300	
Feb-08	16	13,973	873	1,064	
Mar-08	16	14,366	898	833	
Apr-08	16	6,755	422	554	
May-08	16	8,767	548	296	
Jun-08	16	8,525	533	191	
Jul-08	16	4,801	300	132	
Aug-08	16	10,261	641	154	
Sep-08	16	7,475	467	304	
Oct-08	16	11,318	707	524	
Nov-08	16	9,990	624	879	
Dec-08	16	11,591	724	1,387	
Jan-09	16	18,151	1,134	1,329	
Feb-09	15	14,671	978	1,090	
Mar-09	16	10,749	672	1,054	
Apr-09	16	13,478	842	590	
May-09	16	8,685	543	356	
Jun-09	16	7,853	491	131	
Jul-09	15	9,445	630	89	
Aug-09	16	9,893	618	134	
Sep-09	15	9,629	642	279	
Oct-09	15	9,321	621	607	
Nov-09	16	10,917	682	997	
Dec-09	16	11,386	712	1,274	
Jan-10	15	15,541	1,036	1,141	
Feb-10	15	10,010	667	966	
Mar-10	15	10,503	700	764	
Apr-10	14	9,279	663	503	
May-10	15	9,048	603	278	
Jun-10	15	6,189	413	143	
Jul-10	15	7,388	493	71	
Aug-10	15	6,691	446	120	
Sep-10	14	7,628	545	320	
Oct-10	15	4,687	312	517	
Nov-10	15	11,788	786	904	
Dec-10	15	12,259	817	1,292	7,481
Jan-11	14	16,136	1,153	1,201	
Feb-11	15	12,698	847	1,005	
Mar-11	15	12,688	846	1,033	
Apr-11	15	11,864	791	588	
May-11	13	11,444	880	271	
Jun-11	15	5,145	343	143	
Jul-11	14	10,057	718	104	
Aug-11	15	7,866	524	195	
Sep-11	15	9,042	603	292	
Nov-11	15	8,373	558	512	
Nov-11	14	9,394	671	1,059	
Dec-11	12	9,687	807	1,006	8,741
Jan-12	14	17,927	1,281	1,273	
Feb-12	14	10,857	776	936	
Mar-12	14	11,904	850	909	
Apr-12	14	6,044	432	513	
May-12	14	7,985	570	340	
Jun-12	13	8,134	626	150	
Jul-12	14	6,532	467	78	
Aug-12	14	8,450	604	134	
Sep-12	14	6,204	443	259	
Oct-12	14	7,225	516	715	
Nov-12	13	13,038	1,003	1,113	
Dec-12	13	13,024	1,002	1,356	8,568
2013-F				1,218	8,264
2014-F				1,218	8,264
2015-F				1,218	8,264

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Swift River Residential monthly	Customers	Energy (kWh) (Billed)	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	3	4,316	1,439	1,114	
Feb-08	3	4,144	1,381	955	
Mar-08	3	3,160	1,053	735	
Apr-08	3	4,617	1,539	517	
May-08	3	2,000	667	308	
Jun-08	3	2,133	711	226	
Jul-08	3	2,395	798	173	
Aug-08	3	2,135	712	188	
Sep-08	3	2,375	792	319	
Oct-08	3	2,555	852	563	
Nov-08	3	3,005	1,002	783	
Dec-08	3	3,616	1,205	1,186	
Jan-09	3	5,435	1,812	1,138	
Feb-09	3	3,871	1,290	955	
Mar-09	3	4,909	1,636	869	
Apr-09	3	4,224	1,408	515	
May-09	3	4,128	1,376	331	
Jun-09	3	3,610	1,203	144	
Jul-09	3	3,383	1,128	63	
Aug-09	3	3,324	1,108	158	
Sep-09	3	3,430	1,143	306	
Oct-09	3	2,460	820	542	
Nov-09	3	2,460	820	782	
Dec-09	3	2,500	833	943	
Jan-10	2	2,029	1,015	991	
Feb-10	2	1,720	860	679	
Mar-10	2	1,619	810	656	
Apr-10	1	780	780	461	
May-10	2	929	464	292	
Jun-10	3	929	310	172	
Jul-10	3	369	123	117	
Aug-10	2	1,050	525	146	
Sep-10	2	1,134	567	332	
Oct-10	2	903	452	520	
Nov-10	2	2,100	1,050	718	
Dec-10	2	3,113	1,557	1,163	8,511
Jan-11	2	3,226	1,613	1,010	
Feb-11	2	2,072	1,036	906	
Mar-11	2	2,087	1,044	902	
Apr-11	2	3,707	1,854	511	
May-11	2	1,502	751	296	
Jun-11	2	1,129	565	161	
Jul-11	2	1,061	531	128	
Aug-11	2	1,309	655	218	
Sep-11	2	1,281	641	329	
Nov-11	2	1,666	833	513	
Nov-11	2	2,275	1,138	936	
Dec-11	2	2,252	1,126	775	11,784
Jan-12	2	2,851	1,426	1,118	
Feb-12	2	2,307	1,154	708	
Mar-12	2	2,062	1,031	756	
Apr-12	2	2,028	1,014	451	
May-12	2	(2,714)	(1,357)	351	
Jun-12	2	1,739	870	200	
Jul-12	2	1,487	744	140	
Aug-12	2	1,548	774	158	
Sep-12	2	1,608	804	287	
Oct-12	2	1,343	672	631	
Nov-12	2	2,061	1,031	970	
Dec-12	2	1,785	893	1,197	9,053
2013-F				1,045	9,782
2014-F				1,045	9,782
2015-F				1,045	9,782

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Watson Lake
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	930.6	1,266.0	938.7	1,605.2	1,406.6	1,409.7	1,350.2	1,344.8	1,043.4	1,246.3	1,177.5	1,365.6	1,330.3	1,185.2	1,102.4	1,300.1	1,329.3	1,141.4	1,201.0	1,273.0	**1,247.4**
FEB	752.4	119.4	941.9	947.3	884.8	942.0	1,066.4	956.0	1,031.0	970.3	964.7	881.2	941.8	1,016.7	1,017.3	1,064.2	1,089.5	965.8	1,004.6	935.5	**924.6**
MAR	573.0	24.3	855.6	874.3	943.9	843.4	871.4	750.1	844.9	991.6	899.5	809.9	726.9	960.5	1,001.9	833.3	1,054.2	763.5	1,032.9	909.0	**828.2**
APR	347.3	50.1	492.7	547.7	527.9	500.1	506.4	590.9	535.8	694.8	554.4	497.4	464.8	528.2	543.0	554.0	590.0	502.7	587.5	512.6	**506.4**
MAY	190.5	21.8	242.5	366.4	311.8	211.0	372.2	373.8	366.6	365.9	341.6	292.3	256.9	371.1	332.2	295.6	356.0	277.7	271.1	340.2	**297.9**
JUN	99.2	0.8	97.0	163.9	142.6	89.0	140.2	158.0	155.5	147.8	179.9	74.1	126.6	136.5	122.6	191.0	130.6	142.7	143.1	149.7	**129.5**
JUL	83.2	1.2	113.0	103.3	84.1	65.7	99.4	84.3	120.3	121.6	56.6	35.6	136.9	79.2	88.6	131.5	89.0	70.8	104.4	77.8	**87.3**
AUG	66.0	2.3	189.9	185.1	109.6	156.8	127.8	216.9	120.6	181.5	163.0	145.7	162.2	171.7	143.1	154.0	134.4	119.6	195.1	134.0	**144.0**
SEP	298.4	38.8	224.9	354.7	271.1	320.7	292.5	314.8	299.6	331.0	330.2	370.7	297.3	292.4	314.7	304.2	279.4	319.7	292.4	259.4	**290.3**
OCT	248.2	89.8	552.7	662.2	659.7	561.2	519.8	575.8	577.0	514.8	526.1	565.0	541.7	543.3	553.1	523.5	606.9	516.8	511.9	714.5	**528.2**
NOV	127.3	59.4	1,000.2	1,121.2	935.8	958.1	939.9	858.4	975.0	821.9	963.9	875.5	758.4	1,196.2	956.6	879.0	996.5	904.2	1,059.1	1,112.8	**875.0**
DEC	22.1	122.5	1,295.4	1,361.1	983.7	1,252.7	1,013.0	1,222.8	1,275.4	1,117.9	1,095.5	1,070.7	1,061.0	1,050.0	1,255.1	1,386.5	1,273.7	1,292.1	1,006.3	1,356.2	**1,075.7**
TOTAL	**3,738.2**	**1,796.4**	**6,944.5**	**8,292.4**	**7,261.6**	**7,310.4**	**7,299.2**	**7,446.6**	**7,345.1**	**7,505.4**	**7,252.9**	**6,983.7**	**6,804.8**	**7,531.0**	**7,430.6**	**7,616.9**	**7,929.5**	**7,017.0**	**7,409.4**	**7,774.7**	**6,934.5**

Residential Regression Results (YECL 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

Residential (Carmacks)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.848334198
R Square	0.719670911
Adjusted R Square	0.718096029
Standard Error	137.0322957
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8580876.545	8580876.545	456.9679975	4.88748E-51
Residual	178	3342457.313	18777.85007		
Total	179	11923333.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	523.0507986	19.82511653	26.38323956	2.06292E-63	483.9282934	562.1733039	483.9282934	562.1733039
WH-HDD	0.66162154	0.030950434	21.37680981	4.88748E-51	0.600544547	0.722698534	0.600544547	0.722698534

Residential (Carcross)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.73085291
R Square	0.534145976
Adjusted R Square	0.531528819
Standard Error	100.3552824
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2055467.372	2055467.372	204.0939414	2.42352E-31
Residual	178	1792670.521	10071.1827		
Total	179	3848137.893			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	419.1099542	14.51887788	28.86655275	4.6941E-69	390.4586787	447.7612298	390.4586787	447.7612298
WH-HDD	0.323816596	0.022666478	14.28614509	2.42352E-31	0.279087002	0.36854619	0.279087002	0.36854619

Residential (Haines Junction)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.826511766
R Square	0.683121699
Adjusted R Square	0.681341483
Standard Error	70.97827216
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1933198.401	1933198.401	383.7298477	2.73648E-46
Residual	178	896748.8911	5037.915119		
Total	179	2829947.292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	493.5031661	10.26876554	48.0586653	7.1519E-104	473.2389809	513.7673514	473.2389809	513.7673514
WH-HDD	0.31403787	0.016031318	19.58902365	2.73648E-46	0.282401974	0.345673766	0.282401974	0.345673766

Residential (Teslin)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.774809495
R Square	0.600329753
Adjusted R Square	0.598084415
Standard Error	80.08503489
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1714789.401	1714789.401	267.3671534	2.73398E-37
Residual	178	1141623.081	6413.612813		
Total	179	2856412.482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	401.3105811	11.58628439	34.63669349	5.10981E-81	378.4464294	424.1747328	378.4464294	424.1747328
WH-HDD	0.295766652	0.018088193	16.35136549	2.73398E-37	0.260071758	0.331461545	0.260071758	0.331461545

Residential (Ross River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.816954541
R Square	0.667414722
Adjusted R Square	0.665546265
Standard Error	99.84467893
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3560923.245	3560923.245	357.2010799	2.05162E-44
Residual	178	1774474.864	9968.959911		
Total	179	5335398.109			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	420.6644462	14.44500644	29.12179014	1.28614E-69	392.1589471	449.1699452	392.1589471	449.1699452
WH-HDD	0.426211453	0.022551152	18.89976402	2.05162E-44	0.381709441	0.470713465	0.381709441	0.470713465

Residential (Pelly Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.814590942
R Square	0.663558403
Adjusted R Square	0.661668282
Standard Error	106.1935622
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3959003.162	3959003.162	351.0665651	5.74021E-44
Residual	178	2007318.933	11277.07266		
Total	179	5966322.096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	526.6014045	15.3635297	34.27606902	2.58572E-80	496.2833092	556.9194997	496.2833092	556.9194997
WH-HDD	0.449403793	0.023985126	18.7367704	5.74021E-44	0.402072005	0.496735581	0.402072005	0.496735581

Residential (Old Crow)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.700799321
R Square	0.491119688
Adjusted R Square	0.48826081
Standard Error	91.97982219
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1453372.136	1453372.136	171.7875549	6.55924E-28
Residual	178	1505931.209	8460.28769		
Total	179	2959303.345			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	431.2915805	13.30716006	32.41049018	1.39504E-76	405.0314857	457.5516753	405.0314857	457.5516753
WH-HDD	0.272290334	0.020774777	13.10677515	6.55924E-28	0.231293786	0.313286881	0.231293786	0.313286881

Residential (Destruction Bay)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.709031239
R Square	0.502725298
Adjusted R Square	0.49993162
Standard Error	72.69183708
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	950879.8973	950879.8973	179.9510466	8.32101E-29
Residual	178	940570.3656	5284.103178		
Total	179	1891450.263			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	383.8946	10.51667516	36.50341902	1.40822E-84	363.1411947	404.6480054	363.1411947	404.6480054
WH-HDD	0.220245296	0.016418348	13.41458336	8.32101E-29	0.187845643	0.25264495	0.187845643	0.25264495

Residential (Beaver Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.840637508
R Square	0.706671419
Adjusted R Square	0.705023506
Standard Error	87.03187359
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3248177.952	3248177.952	428.8280135	2.78648E-49
Residual	178	1348269.37	7574.547021		
Total	179	4596447.322			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	483.8810515	12.59131671	38.4297419	4.15449E-88	459.0335882	508.7285147	459.0335882	508.7285147
WH-HDD	0.407064957	0.019657222	20.70816297	2.78648E-49	0.368273771	0.445856142	0.368273771	0.445856142

Residential (Tagish)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77755681
R Square	0.604594592
Adjusted R Square	0.602373213
Standard Error	63.68762658
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1103956.052	1103956.052	272.1708788	1.04861E-37
Residual	178	721988.2526	4056.113779		
Total	179	1825944.304			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	234.2954311	9.213993033	25.42821883	3.71752E-61	216.1127137	252.4781485	216.1127137	252.4781485
WH-HDD	0.237312001	0.014384636	16.49760221	1.04861E-37	0.208925636	0.265698366	0.208925636	0.265698366

Residential (Marsh Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.873151604
R Square	0.762393723
Adjusted R Square	0.761058856
Standard Error	88.06938915
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4429873.997	4429873.997	571.1384587	1.93035E-57
Residual	178	1380606.68	7756.217305		
Total	179	5810480.677			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	386.6155856	12.74141904	30.3432125	2.9027E-72	361.4719133	411.7592579	361.4719133	411.7592579
WH-HDD	0.475378456	0.019891558	23.89850327	1.93035E-57	0.436124837	0.514632075	0.436124837	0.514632075

Residential (Deep Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.752248092
R Square	0.565877192
Adjusted R Square	0.5634383
Standard Error	105.7520673
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2594820.496	2594820.496	232.0222255	4.42027E-34
Residual	178	1990662.952	11183.49973		
Total	179	4585483.448			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	248.7081064	15.29965652	16.25579673	5.11914E-37	218.5160572	278.9001555	218.5160572	278.9001555
WH-HDD	0.363829131	0.023885409	15.23227578	4.42027E-34	0.316694123	0.410964139	0.316694123	0.410964139

Residential (Lower Post BC)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.81614908
R Square	0.666099321
Adjusted R Square	0.664223475
Standard Error	102.4652481
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3728162.932	3728162.932	355.0926572	2.91803E-44
Residual	178	1868844.62	10499.12708		
Total	179	5597007.552			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	482.5359337	13.76104774	35.06534841	7.55861E-82	455.3801456	509.6917217	455.3801456	509.6917217
WL-HDD	0.350883145	0.018620514	18.84390239	2.91803E-44	0.31413778	0.387628511	0.31413778	0.387628511

Residential (Upper Liard)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.837904563
R Square	0.702084057
Adjusted R Square	0.700410372
Standard Error	81.41823385
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2780729.358	2780729.358	419.483968	1.11237E-48
Residual	178	1179949.327	6628.928803		
Total	179	3960678.685			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	434.4074757	10.93444093	39.72836641	2.07109E-90	412.8296594	455.9852921	412.8296594	455.9852921
WL-HDD	0.303036141	0.014795742	20.48130777	1.11237E-48	0.273838507	0.332233774	0.273838507	0.332233774

Residential (Watson Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91758524
R Square	0.841962672
Adjusted R Square	0.841074822
Standard Error	62.27248406
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3677439.547	3677439.547	948.3161829	3.18151E-73
Residual	178	690259.4843	3877.862272		
Total	179	4367699.032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	515.255402	8.36317329	61.61003535	5.5467E-122	498.7516761	531.759128	498.7516761	531.759128
WL-HDD	0.348488007	0.011316477	30.79474278	3.18151E-73	0.326156287	0.370819726	0.326156287	0.370819726

Residential (Keno City)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.45197141
R Square	0.204278155
Adjusted R Square	0.199807808
Standard Error	98.54936507
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	443801.0337	443801.0337	45.69625911	1.90467E-10
Residual	178	1728731.969	9711.977356		
Total	179	2172533.003			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	195.761055	14.2576072	13.73028813	1.00194E-29	167.625366	223.8967439	167.625366	223.8967439
WH-HDD	0.150465857	0.022258589	6.759900821	1.90467E-10	0.106541183	0.194390532	0.106541183	0.194390532

Residential (Stewart Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.578269149
R Square	0.334395209
Adjusted R Square	0.330655856
Standard Error	179.1744974
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2870886.34	2870886.34	89.4259596	1.88615E-17
Residual	178	5714423.091	32103.50051		
Total	179	8585309.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	462.7767125	24.06307365	19.23182047	2.54602E-45	415.2911039	510.2623212	415.2911039	510.2623212
WL-HDD	0.307909483	0.032560515	9.456529998	1.88615E-17	0.243655187	0.372163779	0.243655187	0.372163779

Residential (Swift River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.478815384
R Square	0.229264172
Adjusted R Square	0.224934195
Standard Error	309.1635718
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5060894.424	5060894.424	52.9481323	1.05385E-11
Residual	178	17013616.31	95582.11413		
Total	179	22074510.74			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	774.2960938	44.72817013	17.3111507	5.25351E-40	686.0303795	862.5618081	686.0303795	862.5618081
WH-HDD	0.508109656	0.069828406	7.276546729	1.05385E-11	0.370311618	0.645907694	0.370311618	0.645907694

WL-YECL-9

Reference: Purchase Power, Line Losses and Station Service, Section 3

Clarification and additional information is needed on purchased power, line losses and station service.

Request:

(a) Please explain the difference between Primary Purchase Power and Secondary Purchase Power.

(b) Please explain the decreasing and then eliminated use of Secondary Purchase Power.

(c) Please explain the phrase "on the margin" with reference to diesel.

(d) Please explain the purpose and mechanics of the Diesel Contingency Fund.

(e) Please provide a schedule that shows how the annual line losses (6.2%, 6.2%, 6.1%, 6.1% and 6.4% from 2008 to 2012) are calculated.

(f) Please provide a schedule showing loss amounts and percentages by community. Please discuss any trends, and the reasons for the trends, by community. What steps is YECL taking to lower losses?

(g) Please provide a schedule showing station service amounts and percentages by community. Please discuss any trends, and the reasons for the trends, by community. What steps is YECL taking to lower station service?

(h) Please discuss the approaches that are used to maintain optimum station service use and to improve usage in plants with a high station service use percent.

(i) Identify any regulatory approaches that may provide incentives for YECL to reduce losses and maintain optimum station service usage. Please compare the approaches to calculating, managing and using line loss and station service percentages of YECL as compared to its affiliates NUL(YK) and NUL(NWT).

(j) Please indicate whether a cost benefit analysis has been carried out to determine the optimum set of capital investments that would maximize loss reduction and optimize station service use, by community. Please elaborate.

Response:

(a) Primary Purchase Power relates to power purchased for all of Yukon Electrical's firm rate customers. Secondary Purchase Power is for Yukon Electrical's interruptible customers on Rate Schedule 32. Please refer to WL-YECL-9(a) Attachment 1 for a copy of the current Rate Schedule 32.

(b) Secondary or interruptible sales, and the associated purchase power from Yukon Energy, are a function of available surplus hydro as determined by Yukon Energy. As detailed in Yukon Electrical's Application (page 2-8 – 2-9), ongoing non-industrial load growth and connection of new industrial load to the grid have reduced surplus hydro available to such a point where Yukon Energy did not forecast any availability during its 2012-2013 GRA. Yukon Electrical has reflected this forecast as part of its 2013-2015 GRA.

(c) "Diesel on the Margin" is a historical economic reference in the Yukon that refers to the point where the next kWh needed on the hydro grid to meet grid load is met by diesel generation as to opposed hydro generation.

(d) The Diesel Contingency Fund (DCF) was established in the 1996/1997 GRA Negotiated Settlement. The DCF is designed to ensure that the Fund (and utility ratepayers), rather than Yukon Energy and Yukon Electrical earnings, pays for or benefits from changes to grid diesel generation due to fluctuations in grid hydro generation due to factors such as water condition changes that are beyond the utilities control. With the DCF in place, the Board can set customer rates based on long-term forecast hydro generation rather than short-term forecast hydro generation. The DCF is maintained to address ongoing fluctuations in diesel requirements (and related fluctuations in rates, up or down) that ratepayers would otherwise be exposed to due to annual water availability. In effect, the DCF operates to smooth rate impacts so that ratepayers are not subject to ongoing rate instability from year to year depending on whether it is a flood or drought year. Further to the above, on July 16, 2013, the Board directed Yukon Energy to submit a revised DCF Application no later than

September 30, 2013 in conjunction with completing Yukon Energy's 2012-2013 GRA. Yukon Electrical is unable to comment on this pending application at this point in time.

(e) The line losses are calculated simply by dividing line 3 (losses and company used) by line 2 (total energy sales) in Schedule 3.2.

(f) Please refer to WL-YECL-9(f) Attachment 1 for losses by rate zone. Trending has stayed relatively constant for line losses in the hydro zone. Large diesel variability can be attributed to the small size of the zone (town of Watson Lake) and any variability in dates of reporting and additional lines can affect the losses. The increase in small diesel can be attributed to Stewart Crossing and Pelly Crossing power plants being connected to the Yukon Interconnected System and becoming standby plants. The plants now need considerably more heat when units are not running and in standby mode. Old Crow variability can be attributed to the small size of the zone and any variability in dates of reporting and additional lines can affect the losses. Yukon Electrical designs and builds new distribution lines to engineered standards that limit line losses by utilizing larger conductor. Yukon Electrical has also worked to complete voltage conversions in various areas that inherently reduce line losses.

(g) Please refer to WL-YECL-9(g) Attachment 1. The trend identified is that station service is staying constant since 2008. Yukon Electrical has scheduled projects to assess its power plants and reinsulate as needed as heating load tends to be a major load on station service.

(h) Yukon Electrical has completed and plans to complete insulation upgrades to various power plants, as heat is the single largest load on station service. For example, the Stewart Crossing Plant Improvements and Plant Building Insulation projects in 2014 will improve the usage in the Stewart Crossing plant. Yukon Electrical has installed more efficient lighting in appropriate areas. There remain few other loads on station service that can be optimized as computers, control systems, radiator fans, fuel and glycol pumps have to operate as designed.

(i) The current form of cost of service regulation has and continues to incent Yukon Electrical to look for ways to improve losses and station service from that what was forecast. Improved losses and station service achieved during the test period are to the account of the shareholders and, thereafter, to the extent

savings are realized on a go forward basis, they are passed through to customers as part of reduced forecasted costs associated with the next test period. As noted above, however, Yukon Electrical reiterates there are very few options available to significantly improve overall station service and, in some cases, changing standards are resulting in higher station service on a go forward basis.

With respect to comparing approaches to calculating, managing and using line loss and station service percentages of Yukon Electrical to its affiliates Northland Utilities (Yellowknife) and Northland Utilities (NWT), Yukon Electrical notes the NWT the Board has directed the Northland Companies to prepare Engineering Assessments of System Losses to support their forecasts.

(j) No cost benefit analysis was completed. As discussed in (h), there are few options for reducing loads on station service. Equipment such as computers, control systems, radiator fans, fuel and glycol pumps have to operate as designed. The largest single component associated with maintaining optimal plant efficiency is ensuring the diesel engines are maintained in accordance with manufacturer specifications. Yukon Electrical achieves this by completing prescribed ongoing maintenance including the timely completion of minor and major overhauls. Yukon Electrical believes that its engineering standards and system improvement projects directly reduce line losses. All new infrastructure is built to current engineered standards that inherently reduces losses.

RATE SCHEDULE - 32
SECONDARY ENERGY

AVAILABLE:

Secondary energy is available from time to time in parts of the WAF and Mayo systems as determined by YEC and YECL based on the availability of surplus hydro. Qualified, potential customers will be notified by the Company whenever secondary energy is available for periods in excess of one month.

APPLICABLE:

Secondary energy is applicable only to customers satisfying all of the following conditions:

(1) The secondary energy is provided on a separate service fully interruptible at 24 hours notice at the request of the utility. The customer is responsible for the installed cost of the separate service and metering.

(2) YEC and YECL are satisfied that the secondary energy usage is in excess of normal consumption and represents incremental electric usage displacing an alternative fuel source in order to provide space or process heating.

(3) A viable alternative fuel source is available, capable of providing the same quantity of space or process heating in the event of electric power interruptions of unlimited duration.

RATE:

Energy Charge

All Energy Consumption	7.20¢ per kW.h

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

The Yukon Electrical Company Limited
Loss Amounts and Percentages by Rate Zone

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012
Line Loss and Company Used (MWh)					
Hydro Zone	16,739	16,961	16,664	16,604	18,962
Large Diesel	775	665	689	1,059	849
Small Diesel	386	457	403	428	436
Old Crow	102	132	161	127	132
Schedule 3.2, line 3	18,001	18,216	17,917	18,219	20,380
Line Loss and Company Used - % of Sales					
Hydro Zone	6.1%	6.1%	6.1%	5.8%	6.4%
Large Diesel	5.8%	5.0%	5.2%	8.0%	6.0%
Small Diesel	6.8%	13.2%	11.6%	11.8%	11.8%
Old Crow	5.9%	7.4%	9.3%	6.6%	6.6%

The Yukon Electrical Company Limited
Station Service Amounts And Percentages by Rate Zone

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012
Station Service (MWh)					
Large Diesel	255	274	263	270	274
Small Diesel	181	107	113	128	119
Old Crow	44	84	46	39	53
Schedule 3.2, line 3	480	464	422	437	446
Station Service - % of Gross Generation					
Large Diesel	1.8%	1.9%	1.8%	1.8%	1.8%
Small Diesel	2.9%	2.7%	2.8%	3.0%	2.8%
Old Crow	2.4%	4.2%	2.4%	1.8%	2.4%

WL-YECL-10

Reference: Fuel Costs, Heat Rates, Schedule 4.2

The heat rates for Swift River and the Standby Units are lower than the heat rates for the other plants.

Request:

(a) Please explain why the heat rates for Swift River and the Standby Units are much lower than the other plants. Is YECL taking steps to increase the heat rates in these, and all other, plants?

(b) How and when are the heat rates measured to verify their accuracy as used in the GRA forecasts? Please describe in detail how YECL compiles and reports data respecting plant efficiencies. Include details of how the data is gathered and monitored by individual generating unit/plant, the technology used to monitor and compile data, the frequency with which data is collected and reported.

(c) Please discuss the approaches that are used to maintain optimum plant efficiencies and to improve the ones with low efficiencies. Identify any regulatory approaches that may provide incentives for the Company to maintain optimum plant efficiencies. Compare YECL's approach to calculating, managing and using plant efficiencies in its GRA forecasts as compared to its affiliates NUL(YK) and NUL(NWT).

Response:

(a) The Swift River power plant is the smallest, in physical size and generator rating, of Yukon Electrical's running plants. The 2 units that are rated for 80 kW frequently run in the 40% - 60% of their rating as demonstrated by the 2012 average peak of 41.2 kW. Though their average running load is lower than their rating, the units must be of sufficient rating to allow for cold load pick up of the community. If the community is off for an hour or more in winter, both units need to run synchronously to successfully restore power to the community. The Standby Units run infrequently during loss of supply or outages to the Yukon Interconnected System. With their programmed warm-up and subsequent cool down cycles they will run with little to no load until the engine has warmed up or cooled down sufficiently. Standby Units will use station service power at all

times regardless if the unit is dispatched for service. Plant lighting, computer systems, heating and associated devices are operational even if the plant does not run in a given month. There is little Yukon Electrical can do to dispatch the existing units in Swift River to match the community load to improve the heat rate. Similarly, for the Standby Units, there is little Yukon Electrical can do to dispatch the units to match the community load to improve the heat rate. However, Yukon Electrical has improved building insulation and installed automated louvers.

(b) Heat rates are verified monthly as part of the monthly plant reporting process. Reports are compiled by taking fuel consumed and kWh produced. These are then reviewed by the plant maintenance man. Any issues are raised to the Superintendent of Operations. This process is the same for all plants. The technology used to produce kWh data is Supervisory Control and Data Acquisition ("SCADA"). Yukon Electrical is also in the process of adding fuel tank level monitoring to SCADA.

(c) The largest single component associated with maintaining optimal diesel fuel efficiency is ensuring the diesel engines are operated and maintained in accordance with manufacturer specifications. Yukon Electrical achieves this by dispatching units to match system loads and by completing prescribed ongoing maintenance including the timely completion of minor and major overhauls. Yukon Electrical monitors operating conditions and will adjust generating equipment for the best efficiency. The next component associated with optimal plant efficiency, a very small one in relation to the maintenance of diesel engines, is station service. Station service electricity is needed for such things as plant lights, switch gear, radiator fans, fans for plant cooling, fuel pumps and electric heat. Given the nature of this station service load, Yukon Electrical has and continues to have very few options available to reduce station service.

At the forecasted time of replacement, the community loading, both annual peak and load duration curves will be examined and taken into consideration. Yukon Electrical will select a unit at the time of tender to ensure ideal generator capacity is selected. Although a generator is selected to best match the community loading, Yukon Electrical notes that new diesel engines have to meet improved emission standards. This means the incorporation of devices that can actually reduce the efficiency of the engine, such as modification to fuel combustion conditions or post combustion pollution controls that add to exhaust back pressure, which will improve emissions at the expense of optimal power

performance. Please refer to WL-YECL-10(c) Attachment 1 for an example of this for a 150 kW Volvo diesel engine between 1997 and 2010.

With respect to the question on the identification of any regulatory approaches that may provide incentives for the Company to maintain optimum plant efficiencies, Yukon Electrical notes the current form of cost of service regulation has and continues to incent Yukon Electrical to look for ways to improve plant efficiencies from what was forecast. Efficiencies achieved during the test period are to the account of the shareholders and, thereafter, to the extent savings are realized on a go forward basis, they are passed through to customers as part of reduced forecasted costs associated with the next test period. As noted above, however, Yukon Electrical reiterates there are very few options available to significantly improve overall plant efficiencies and, in some cases, changing standards are resulting in lower efficiencies on a go forward basis.

With respect to comparing Yukon Electrical's approach to calculating, managing and using plant efficiencies in its GRA forecasts as compared to its affiliates Northland Utilities (Yellowknife) and Northland Utilities (NWT), Yukon Electrical notes Northland Utilities (Yellowknife) does not have any generation assets. In the case of Northland Utilities (NWT), the NWT Public Utilities Board has directed Northland to use a weighted average of 3 years of data with a weighting of "3" given to the highest efficiency year, a weighting of "2" to the middle efficiency year and a weighting of "1" given to the lowest efficiency year, adjusted for the forecast fuel efficiencies of any new engines forecast to be in service. Yukon Electrical, as well as Northland, maintains that a historical average that is a more accurate and appropriate method to forecast heat rates in the absence of major changes to engines and associated engine efficiencies. The use of a weighted approach limits the utility's ability to recover prudently incurred costs especially in instances where units are becoming less fuel efficient due to higher emission standards.

Comparisons of Volvo 150kW Units From 1997 to 2010
Changes in Heat Rate, Station Service and Emissions

Heat Rate

Model	Size	Year Manufactured	25%	50%	75%	100%	Average
TWD 710G	150KW	1997	3.35	3.87	4.03	4.05	3.83
TAD733GE	150KW	2010	3.44	3.8	3.83	3.8	3.72

Station Service

Model	Size	Year Manufactured	Radiator Fan Motor		ATAC Fan Motor	
TWD 710G	150KW	1997	Yes	5HP *	No	N/A
TAD733GE	150KW	2010	Yes	5HP *	Yes	5HP *

Emissions

Model	Size	Year Manufactured	ATAC Emissions Device
TWD 710G	150KW	1997	No
TAD733GE	150KW	2010	Yes

Note: * signifies that the Radiator or ATAC Fan motor cycles as required depending on loading and ambient temperature.

WL-YECL-11

Reference: Fuel Costs, Section 4, Page 4-1

Diesel fuel is purchased for each of the five diesel plants operated by YECL. YECL conducts a fuel tendering process in which a vendor is selected to be the exclusive provider of fuel to YECL. The current diesel fuel arrangements are due to be retendered early in 2014.

Request:

(a) Please describe the pricing mechanism for diesel fuel supply to each of the communities that is currently in place and, the pricing mechanism that would apply during the test period. Indicate the expiry date of the current supply contract.

(b) Please describe the fuel tendering process used by YECL. How long was the current contract and how long will the next contract be? Explain why YECL considers this process to result in competitive fuel prices throughout the contract period.

Response:

(a) The price of diesel fuel supply to each of the communities is based on the daily rack price plus a delivery cost (each community is different depending on its proximity and accessibility). These pricing mechanisms follow historical trends and are expected to continue during the test period.

Currently, Yukon Electrical has a supply contract with Suncor Energy Partners for fuel delivery to the following communities: Beaver Creek, Haines Junction, Destruction Bay, Swift River, Teslin, Watson Lake, Pelly Crossing, Ross River and Stewart Crossing. This contract expires on January 31, 2014.

Yukon Electrical recently completed contract negotiations with Air North for a new supply agreement for Old Crow. The new contract is for a three year term expiring on June 30, 2016.

(b) Yukon Electrical's fuel tendering process involves identifying potential bidders and inviting them to bid on fuel supply to the list of Yukon communities. It is

noted that if a bidder can only supply to a subset of these communities Yukon Electrical will still consider their bid. Once the deadline has passed, Yukon Electrical receives support from ATCO Electric's purchasing department in Edmonton. The purchasing department collects the bids, reviews them and provides a summary and analysis on the bidders' submissions. This is forwarded to Yukon Electrical with an initial recommendation for selection. Yukon Electrical management then does further analysis and a selection is made.

The current Suncor contract has a one year term and expires January 31, 2014. The next contract with the winning bidder will be for a one to three year period, depending on what incentives suppliers provide to enter into a contract for a longer period of time.

In the case of Old Crow, Air North is the only supplier that currently flies the community, supplying fuel to both Yukon Electrical and the Government of the Yukon. When a contract with Air North expires, Yukon Electrical scans the industry to determine whether alternative suppliers are available. If alternative suppliers were to be identified, the same tendering process as described above would be used. However, the Air North contract recently expired and was renewed and Yukon Electrical did not tender the contract as no alternative supplier was available at this time.

Yukon Electrical considers this process to provide competitive prices for the length of the contract period. The contracted price of fuel is significantly based on rack price. These prices are market driven and fluctuations are consistent across suppliers. Delivery prices also contain a component that is dependent on the market price of fuel. When a contract is selected, Yukon Electrical looks for the most competitive price for the non-variable components of the pricing calculation, but also must evaluate suppliers on reliability, and safety record. As some of our communities depend on diesel generation as the sole source of power, Yukon Electrical has an obligation to ensure that prices are competitive, but also that reputable and reliable supplier agreements are in place.

WL-YECL-12

Reference: Pension Expense, Section 5, Page 5-3

YECL does not provide a forecast of pension expenses and is also proposing to use a deferral account to flow through increases or decreases to required cash contributions to the company's defined benefit pension plan as a result of the required annual actuarial evaluations.

Request:

Please explain, in much more detail than is provided in the application, the functioning of the pension plans. More specifically:

(a) How were the amounts of the Defined Benefit payments for 2010 to 2012 calculated?

(b) What is the reason and purpose for the DB Special Payments for 2010 to 2012? How were these amounts calculated?

(c) On what basis is YECL assuming that the 2013 DB contribution rates will be the same as 2012?

(d) The application states that the next actuarial evaluation to determine the 2013 DB funding requirements was to be completed as of Dec. 31, 2013. Should this have been Dec. 31st, 2013? If no, then please describe the outcome of that evaluation.

(e) Is the purpose of the proposed deferral account to handle what was in 2010 to 2012 the DB Special Payments? Please explain the purpose and functioning of the proposed deferral account in more detail.

(f) Please provide schedules showing the actual and forecast payments to the defined benefit and defined contribution plans for the period from 2008 to 2015, both in percent of payroll and actual amounts. Please explain any significant variations in these costs. Please explain why the company's contribution to the defined contribution plan is 6% and explain if that amount could change during the test years.

(g) Please provide a schedule showing the actual and forecast OPEB costs for the period from 2008 to 2015, both in percent of payroll and actual amounts. Please explain any significant variations in these costs.

Response:

(a) The Defined Benefit payments for 2010 and 2011 were calculated based on the actuarial valuation prepared as at December 31, 2009. The actuarial valuation determined a % of pensionable salary to be funded based on the total funding required divided by the forecast pensionable salary for the year. The % was then applied to the actual pensionable salary to determine the actual cash payments.

The Defined Benefit payment for 2012 was based on the actuarial valuation prepared as at December 31, 2012. The actuarial valuation determined the total funding required and this was the amount paid.

(b) The DB Special Payments are required to fund the unfunded liability in the plan. Where the defined benefit portion of the plan has an unfunded liability, the employer must contribute, on at least a monthly basis (or as a lump sum if desired), special payments sufficient to amortize the unfunded liability over a period not exceeding 15 years from the date the unfunded liability was established.

These amounts were calculated by Mercer (Canada) Limited, the preparer of the actuarial valuations for the period.

(c) Yukon Electrical is not expecting the 2013 DB contribution rates will be the same as 2012. At the time the filing was prepared, the valuation as at December 31, 2012, which determines the 2013 funding, had not yet been completed. As a result, Yukon Electrical had no better information with which to forecast the 2013 DB contributions than the 2012 actual funding.

(d) An actual valuation as of December 31, 2012, which is used to determine 2013 funding requirements, was completed in July 2013 (please refer to YUB-YECL-5(a) Attachment 1). As a result of the valuation, Yukon Electrical's required DB pension funding for 2013 is as follows:

Current service	$605,000
Special payment	$351,000
Total	$956,000

(e) Beginning in 2013, the purpose of the proposed deferral account is to flow through all non-capitalized increases or decreases to required cash contributions to the defined benefit pension plan. This includes both the current service and special payment portions of the contributions.

(f) Please refer to WL-YECL-12(f) Attachment 1 for a schedule showing the actual and forecast payments to the defined benefit and defined contribution plans for the period from 2008 to 2015.

DB pension contributions are determined based on actuarial valuations. These valuations are impacted by many factors including the performance of the investments held by the pension plan, inflation rates, and changes in actuarial assumptions including mortality rates. As a result, DB contributions will fluctuate from year to year.

The company's contribution to the defined contribution plan is 6% and it is reviewed annually by management as part of its review of the compensation package offered by the company. No changes are forecast to the employer contribution rate of 6% for the test period.

(g) The actual and forecast OPEB costs for the period from 2008 to 2015 are as follows:

Year	GRA Forecast	Actual
2008 Actual	60	37
2009 Actual	60	24
2010 Actual	N/A	20
2011 Actual	N/A	11
2012 Actual	N/A	37
2013 Forecast	37	N/A
2014 Forecast	37	N/A
2015 Forecast	37	N/A

Since 2008, Yukon Electrical has accounted for OPEB on the cash basis, which means that the actual cash outlay is expensed. The cash outlay is based on the claims made by retirees for their health and dental care in each year and is not impacted by the total current payroll expenses. Therefore, the percentage of payroll is not applicable and was not calculated. The forecast is based on past experience as well as growth in the number as well as age of retirees.

The Yukon Electrical Company Limited
Actual and Forecast Pension Payments 2008-2015

	Current Service Payments	Special Payments	Total DB Payments	DB Pensionable Salary	Payments as % of DB Salary	Defined Contribution Payments	DC Pensionable Salary	Payments as % of DB Salary
2008 Forecast	487	93	580	2,148	27.00%	(1)	(1)	(1)
2009 Forecast	517	98	615	2,278	27.00%	(1)	(1)	(1)
2008 Actual	521	99	620	2,296	27.00%	(1)	(1)	(1)
2009 Actual	566	86	652	2,415	27.00%	(1)	(1)	(1)
2010 Actual	509	284	793	2,141	37.04%	121	2,017	6.00%
2011 Actual	543	303	846	2,284	37.04%	162	2,700	6.00%
2012 Actual	630	638	1,268	(2)	(2)	166	2,767	6.00%
2013 Forecast	630	638	1,268	(2)	(2)	172	2,867	6.00%
2014 Forecast	630	638	1,268	(2)	(2)	178	2,967	6.00%
2015 Forecast	630	638	1,268	(2)	(2)	184	3,067	6.00%

(1) Yukon Electrical employees are part of two different pension plans sponsored by Canadian Utilities Ltd. - Plan 1 (DC) and Plan 2 (DB). Plan 1 was considered fully funded until 2010 and, as a result, no contributions to the DC plan were required for 2008 and 2009.

(2) Prior to 2012, the pension valuation determined a % funding requirement for both current service and special payments based on the required funding amount divided by a forecast of pensionable salary. Actual cash contributions were calculated based on the calculated % multiplied by the actual pensionable salary. As result, each year there was a slight difference between the required funding and the actual payments made.

Beginning in 2012, the method for calculating the actual cash payments changed. The actuarial valuation calculates the required funding amount and the actual payments are made to exactly equal to this amount. As a result, the funding is no longer based on a % of pensionable salary so it was not calculated for 2012-2015.

WL-YECL-13

Reference: O&M Expense, Section 5, Schedules 5-1 and 5.2

The Town wishes to examine some of the O&M expense increases proposed for the test period.

Request:

(a) Labour and fringe are cited in numerous areas as responsible for increased expenses. Please provide a schedule showing labour and fringe expenses for 2008 to 2015 for each of the accounting areas shown in Schedule 5.1. Please describe what is included in "fringe".

(b) Fish Lake is described in Schedule 5.1 as a major driver of increased costs but little detail is provided. Please provide a schedule that details all of the Fish Lake costs for 62600 – Hydro Production for the period from 2012 to 2015.

(c) Please provide a detailed schedule of expenses for 64600 – Diesel Generation for the period from 2012 to 2015.

(d) 84600 – Diesel Maintenance. YECL states that the cost increase in 2012 is mainly due to overall higher contractor costs. Please explain this in more detail. Were these higher costs due to an increased level of maintenance activities? If yes, please explain why. Were these higher costs due to contractors increasing their rates? If yes, please explain what YECL is doing to ensure to control its contractor costs.

(e) 87000 – Supervision. Please explain what YECL has done to determine why its after-hour calls have been increasing and what it has done to reduce the usage of its after-hours service.

(f) 87800 – Street Light Maintenance. Why are there higher levels of streetlight repair activity in the test years?

(g) 72200 – Administration Corporate. Please explain why there is not a larger drop from 2012 to 2013 given that 2012 included regulatory intervention costs of $103,000.

(h) 72300 – Insurance. Page 5-5 refers to the removal of distribution line insurance coverage. Schedule 5.2 refers to the removal of transmission and distribution line coverage. Please explain the difference.

(i) 72500 – Employee Expenses. Please explain the change in policy.

(j) 72600 – Training and Safety. Please explain in more detail the increase in costs in 2012.

(k) With reference to Schedule 5.3, please provide reasons for the increases in information technology (IT) and billing system services (ITBS) in the test period relative to 2012 actuals. Include a schedule showing the rates and volumes of IT and ITBS services in each of 2012, 2013, 2014 and 2015.

(l) With reference to Schedule 5.3, please provide detailed reasons for the increases in Financial Reporting and Regulatory Support from 2010 to 2015.

Response:

(a) Please refer to WL-YECL-13(a) Attachment 1. Fringe costs include the following: defined benefit pension payments, defined contribution pension payments, CPP/EI/WCB payroll costs, medical, dental, group life insurance, and short and long term disability.

(b) Please refer to YUB-YECL-8 Attachment 1.

(c) The following table provides a detailed breakdown of account 64600:

		Actual	Test Period		
		2012	2013	2014	2015
Labour		249	246	253	261
Fringe Benefits		79	65	65	66
Telephone and Fax		35	33	34	34
Contractor Services		80	79	80	82
Materials Purchased		14	8	8	8
LNG Storage and Vapourization	Sch 5.3, L.6	-	88	264	264
Total for 64600	Sch 5.1, L.4	**457**	**519**	**704**	**715**

(d) The cost increase in 2012 for account 84600 is due to the following:

- Increased volume of maintenance activities, including overhauls on Watson Lake Units #1, #2 and #6 as well as Pelly Crossing Unit #2 in 2012.

- Please refer to WL-YECL-13(d) Attachment 1 for information on contractor rate increases from 2011 to 2012, which shows an approximate 5% increase in contractor rates. A competitive tender process is used to ensure that contractor costs are fair and reasonable.

(e) While Yukon Electrical has seen modest increases in the amount of calls being covered by AHA, the major reason for the step increase between 2012 and 2013 is due to ATCO Electric completing a detailed usage review of AHA services in 2012. This review determined Yukon Electrical's fair share of costs based on usage needed to be increased to reflect what was actually taking place. In essence, Yukon Electrical was under charged by ATCO Electric for this service in 2012.

In summary, the reasons for the increase between 2012 and 2013 are as follows:

- Completion of an updated activity based costing methodology;

- An increase in the coverage provided from 5 PM – 8 AM weekdays to 4 PM – 8 AM weekdays;

- Increasing volume of after hour calls.

Further to the above, for 2012, the number of calls averages out to roughly 13.4 calls per day for 365 days a year. The hours of coverage are 14 hours per day for 249 days of the year and 24 hours for the 116 days of weekends and stat holidays. At the 2013 annual forecast cost of $62,000, the cost for this critical service is $9.89 per hour.

AHA Call Center			
Yukon Electrical - Calls Answered			
	Year		
	2011	2012	
Outage calls answered	3,433	3,633	
Yukon Electrical PLT call-in	1,177	1,263	
Total calls answered	**4,610**	**4,896**	
Average call volume per day (365 days a year)		13.4 calls	

AHA Call Center			
Yukon Electrical - 2013 Forecast Cost per hour of coverage			
Coverage breakdown - 365 days of year:	Days	Hours	Tot Hrs
Weekend days (24 hour)	104	24	2,496
Statutory holidays (24 hour)	12	24	288
Balance of weekdays at (14 hour 4pm-8am)	249	14	3,486
	365		6,270
Schedule 5.3, Line 3 - Total Cost			$ 62,000
Total hours of coverage			6,270
Total (fully loaded) Cost per hour			**$ 9.89**

The after-hours service used by Yukon Electrical is a critical aspect of its operations both with respect to responding to customers as well as monitoring the status of employees when they are working after-hours. With respect, there is nothing Yukon Electrical can do to reduce its usage without significantly compromising customer service and employee safety.

(f) The costs increase in the test years due to inflation and increased numbers of lights with the new development in the Whitehorse area.

(g) Please see the table below for more detail on account 72200:

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
Bank Charges	29	42	71	93	135	137	140
Regulatory Expenses	120	142	-	103	-	-	-
	149	184	71	196	135	137	140

Bank charges are forecast to increase as a result of the continued increase in customer credit card usage in 2013.

(h) This was a typo as Yukon Electrical does not own or operate transmission lines.

(i) The policy has increased from an $800 travel allowance per family member to $900, effective January 1, 2013 per the collective bargaining agreement.

(j) The increase in costs in 2012 was attributable to two training courses for our high risk frontline employees. A total of 42 employees attended Equipotential Bonding and Grounding as well as Fall Arrest & Pole Top Rescue training. Please refer to YUB-YECL-14 for more information on training costs.

(k) Please refer to WL-YECL-13(k) Attachment 1 for a table of ITEK volumes and prices. The reason for the increase in costs is mainly due to various increased volumes due to increasing staff and disk storage as well as inflation. These factors are offset by rate decreases in some instances. For ITBS costs, please refer to YUB-YECL-6(g) Attachment 1. Costs increase mainly due to volumes for 2013 and 2014, inflation on pass-through costs as well as the use of average actual costs incurred from 2009-2012 for various ad hoc billing system special requests that occur during a year. Costs increase in 2015 due to inflation as well as volume increases.

(l) Financial Services and Regulatory Support costs increased from 2010 to 2011 as a result of the Supervisor, Financial Services position being relocated from Whitehorse to Edmonton in the fourth quarter of 2011. Prior to the relocation, the position was filled by an employee of Yukon Electric and, as a result, was not considered a charge from an affiliate.

Financial Services and Regulatory Support costs increased from 2011 to 2012 due to the full year impact of the relocation of the Supervisor, Financial Services as discussed above, as well as the addition of the Corporate Accountant at the beginning of the year and the Manager, Financial Account & Reporting, North of 60 at mid-year.

Financial Services and Regulatory Support costs increased from 2012 to 2013 due to the full year impact of the Manager, Financial Account & Reporting, North of 60 as discussed above.

Financial Services and Regulatory Support costs increased from 2013 to 2014 and 2014 to 2015 as a result of inflation.

The Yukon Electrical Company Limited
Breakdown of Operations and Maintenance Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	2014	2015
Production									
62600 - Hydro Generation	Fringe	11	10	11	12	19	30	57	61
	Labour	62	64	71	64	75	124	216	233
	Other	19	47	29	32	60	166	146	160
		92	121	111	108	154	320	419	454
64000 - Supervision and Engineering Diesel	Fringe	12	12	12	12	16	15	15	16
	Labour	47	48	49	49	51	48	50	52
	Other	-	0	-	2	2	1	1	1
		59	60	62	63	69	65	67	69
64600 - Diesel Generation	Fringe	52	56	81	80	79	65	65	66
	Labour	219	251	294	330	249	246	253	261
	Other	88	117	113	191	128	208	386	389
		358	424	487	601	457	519	704	715
82600 - Hydro Maintenance	Fringe	5	4	2	5	2	3	3	3
	Labour	22	14	7	21	9	11	11	12
	Other	22	15	11	37	94	35	36	36
		49	33	19	63	105	48	49	51
84600 - Diesel Maintenance	Fringe	73	78	85	69	89	82	81	82
	Labour	338	364	318	322	271	290	299	309
	Other	628	567	510	622	833	845	857	870
		1,038	1,010	913	1,013	1,193	1,216	1,238	1,261
Total Production		**1,596**	**1,647**	**1,593**	**1,849**	**1,978**	**2,169**	**2,477**	**2,550**

The Yukon Electrical Company Limited
Breakdown of Operations and Maintenance Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	2014	2015
Distribution									
87000 - Supervision	Fringe	42	38	47	41	55	55	54	55
	Labour	170	202	156	163	160	172	177	183
	Other	28	30	32	38	48	71	73	76
		240	270	234	242	263	297	305	314
87100 - Brushing	Fringe	15	18	11	8	12	11	11	11
	Labour	63	68	50	36	37	37	38	39
	Other	252	249	295	239	493	355	362	369
		329	335	355	283	543	403	411	420
87200 - Vehicle Depreciation	Other	(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
		(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
87300 - Maintenance	Fringe	172	226	308	259	334	313	312	327
	Labour	786	1,035	1,158	1,167	1,127	1,224	1,261	1,335
	Other	377	418	303	383	477	452	461	470
		1,335	1,679	1,769	1,808	1,938	1,989	2,034	2,132
87310 - Service to Outside Parties	Other	70	83	64	90	101	103	105	107
		70	83	64	90	101	103	105	107
87400 - Underground Line Maintenance	Fringe	14	16	13	14	32	33	33	38
	Labour	59	71	55	58	110	105	108	128
	Other	30	32	26	19	63	36	36	37
		103	119	95	91	205	173	177	203
87500 - Meter and Meter Testing	Fringe	12	10	16	9	5	7	7	7
	Labour	47	40	51	37	14	22	22	23
	Other	98	68	27	54	90	60	62	64
		157	118	94	101	108	89	91	94
87700 - Transformer Repair and Replacement	Fringe	1	-	1	1	9	10	11	12
	Labour	5	4	9	10	38	36	37	41
	Other	24	8	26	35	65	32	32	33
		29	12	36	47	112	78	81	87
87800 - Street Light Maintenance	Fringe	13	15	15	13	20	22	22	25
	Labour	54	67	60	55	71	76	78	87
	Other	101	82	92	92	90	95	97	99
		168	164	167	160	181	193	197	210
Total Distibution		**2,336**	**2,638**	**2,662**	**2,659**	**3,281**	**3,141**	**3,215**	**3,376**

The Yukon Electrical Company Limited
Breakdown of Operations and Maintenance Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	2014	2015
General									
88400 - Communication	Fringe	-	-	-	-	-	-	-	-
	Labour	-	2	-	1	1	1	1	1
	Other	8	17	10	9	14	11	11	12
		8	18	10	10	15	12	13	13
88800 - Maintenance Company-Owned Houses	Fringe								
	Labour	-	-	1	-	-	-	-	-
	Other	32	11	17	16	16	17	17	18
		32	11	18	16	16	17	17	18
88900 - Maintenance Warehouse and Office	Fringe	-	-	1	-	1	1	1	1
	Labour	2	2	3	2	4	4	4	4
	Other	105	111	118	114	142	124	127	129
		108	113	122	115	147	129	132	135
Total General		**148**	**142**	**150**	**141**	**178**	**159**	**162**	**165**
Marketing									
70100 - Public Information Administration	Fringe	5	5	6	5	5	4	4	4
	Labour	20	20	24	19	15	12	12	12
	Other	63	47	15	11	8	12	12	12
		88	73	45	35	28	27	28	28
70200 - General Public Information	Fringe	-	2	4	10	17	21	21	21
	Labour	-	9	16	39	56	66	69	71
	Other	17	39	38	28	36	37	37	38
		17	50	58	76	109	124	127	130
Total Marketing		**105**	**122**	**104**	**111**	**137**	**151**	**155**	**159**

The Yukon Electrical Company Limited
Breakdown of Operations and Maintenance Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	2014	2015
Customer Accounting									
71000 - Supervision	Fringe	6	9	9	7	12	13	13	13
	Labour	24	44	33	27	40	41	42	43
	Other	0	-	-	0	-	-	-	-
		30	53	41	34	52	54	55	56
71100 - Customer Applications and Service Orders	Fringe	62	74	77	73	101	101	106	112
	Labour	245	298	268	289	288	321	348	374
	Other	50	75	64	48	55	56	57	58
		356	447	410	410	444	478	510	543
71200 - Meter Reading	Fringe	70	70	87	71	92	101	100	81
	Labour	284	281	301	287	264	324	335	279
	Other	175	192	144	104	127	138	141	144
		530	543	532	462	484	563	576	504
71300 - Customer Billing and Accounting	Fringe	30	34	46	35	44	46	46	47
	Labour	127	148	155	139	122	145	150	155
	Other	407	520	495	529	529	558	569	588
		564	702	696	703	695	749	765	789
71400 - Revenue Collections	Fringe	40	32	41	32	47	53	53	54
	Labour	160	135	137	129	129	168	173	178
	Other	9	8	(12)	7	6	7	7	7
		209	176	165	168	182	228	233	239
71500 - Collection of Delinquent Accounts	Fringe	23	18	24	20	31	32	31	32
	Labour	92	75	86	81	85	99	103	106
	Other	16	5	8	8	8	9	9	9
		131	98	119	110	123	140	143	147
71800 - Provision for Uncollectible Accounts	Other	36	34	43	36	36	36	36	36
		36	34	43	36	36	36	36	36
Total Customer Accounting		**1,857**	**2,054**	**2,006**	**1,922**	**2,016**	**2,248**	**2,318**	**2,316**

The Yukon Electrical Company Limited
Breakdown of Operations and Maintenance Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	2014	2015
Administration									
72100 - Administrative	Fringe	128	116	162	144	152	191	190	192
	Labour	564	579	658	759	639	670	692	714
	Other	823	810	825	890	1,238	1,445	1,567	1,538
		1,515	1,505	1,645	1,792	2,028	2,306	2,448	2,445
72200 - Administrative Corporate	Other	27	149	184	71	196	135	137	140
		27	149	184	71	196	135	137	140
72300 - Insurance	Other	207	228	215	244	245	262	202	138
		207	228	215	244	245	262	202	138
72400 - Injuries & Damages	Other	75	97	86	86	86	124	124	125
		75	97	86	86	86	124	124	125
72500 - Employee Expenses	Fringe	20	16	16	22	23	23	23	23
	Labour	82	66	67	62	75	73	75	78
	Other	128	152	170	170	149	182	185	189
		231	234	253	254	248	278	283	290
72600 - Training and Safety	Fringe	47	58	72	61	94	87	87	88
	Labour	188	244	257	243	270	276	285	296
	Other	76	103	76	83	92	106	107	110
		312	406	404	387	456	469	479	494
72700 - Relocation	Fringe	1	-	1	5	2	2	2	3
	Labour	7	2	4	17	7	8	8	11
	Other	101	51	208	185	57	150	152	156
		109	52	213	207	66	160	163	170
72800 - Miscellaneous General	Other	5	-	-	-	-	-	-	-
		5	-	-	-	-	-	-	-
72900 - Audit/Legal Fees & Special Studies	Fringe	4	3	2	1	5	3	2	3
	Labour	16	14	10	3	18	8	8	8
	Other	52	182	98	73	121	122	145	128
		71	200	110	76	144	133	156	138
Total Administration		**2,551**	**2,870**	**3,110**	**3,117**	**3,468**	**3,866**	**3,992**	**3,940**
Total O&M		**8,593**	**9,474**	**9,625**	**9,799**	**11,059**	**11,735**	**12,319**	**12,507**

Finning Rates

	2011	2012	% increase
Regular Retail Shop Rate	144.50	151.50	**4.84%**
OT Retail Shop Rate	197.00	206.25	**4.70%**
Regular Retail Field Rate	171.75	180.00	**4.80%**
OT Retail Field Rate	225.00	235.50	**4.67%**
Travel Time Reg Retail Rate	147.75	151.50	**2.54%**
Travel Time OT Retail Rate	201.25	201.25	**0.00%**

The Yukon Electrical Company Limited
An ATCO Company

BLANKET PURCHASE ORDER

ORDER NUMBER YECL27371
REVISION 5
28-MAR-2011
PAGE 1 OF 3

TO (SUPPLIER)	FINNING INTERNATIONAL INC PO BOX 2405 EDMONTON, AB T5J 2S1 CANADA Fax: (780) 483-2412
SHIP TO	The Yukon Electrical Company Limited **MULTIPLE LOCATIONS - SEE BELOW**

ORDER DATE	17-FEB-2010
PAYMENT TERMS	NET 30
FREIGHT TERMS	PAID
TRADE TERMS	DESTINATION
SHIP VIA	
BILL TO (PURCHASER)	The Yukon Electrical Company Limited Whitehorse Office Accounts Payable 100, 1100 - 1 Avenue Whitehorse, YT Y1A 3T4 Canada PHONE 867-633-7007 FAX 867-668-6692

AS PER FINNING INTERNATIONAL INC. EMAIL CORRESPONDENCE DATED JANUARY 4, 12, 13, 14, AND 28; FEBRUARY 3 & 16, 2010 AND ATCO ELECTRIC EMAILS DATED DECEMBER 17 & 30, 2009 AND JANUARY 12, 14, 19, & 26 AND FEBRUARY 10, 2010.

.

REVISION #5 IS TO EXTEND THE BLANKET ORDER FOR SERVICES UNTIL APRIL 30, 2012 AS PER EMAIL QUOTE FROM WADE HARRISON ON MARCH 23, 2011 WITH THE RATES REMAINING THE SAME AS 2010.

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EFFECTIVE FROM 17-FEB-2010 TO 30-APR-2012 ESTIMATED AGREEMENT AMOUNT $1,150,000.00

LINE	ITEM	DESCRIPTION	QUANTITY	UNIT		UNIT PRICE	AMOUNT
1		MISCELLANEOUS PARTS FOR GENERATING PLANTS (NOT IDENTIFIED BELOW)					
2		MISCELLANEOUS SERVICE FOR GENERATING PLANTS (NOT IDENTIFIED BELOW)					
3	2010/2011 rates	REGULAR RETAIL SHOP RATE		HOURS		$144.50	
4		OVERTIME RETAIL SHOP RATE		HOURS		$197.00	
5		REGULAR RETAIL FIELD RATE		HOURS		$171.75	
6		OVERTIME RETAIL FIELD RATE		HOURS		$225.00	
7		TRAVEL TIME REGULAR RETAIL RATE		HOURS		$147.75	
8		TRAVEL TIME OVERTIME RETAIL RATE		HOURS	X	$201.25	

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
Chocho, Michael W Mike.Chocho@atcoelectric.com	780-420-7138	780-420-7436

To report inappropriate commercial or purchasing practices, please call the following:
Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

The Yukon Electrical Company Limited
An *ATCO* Company

BLANKET PURCHASE ORDER

ORDER NUMBER **YECL27371**
REVISION 6 **19-APR-2012**
PAGE 2 OF 4

TO (SUPPLIER)	FINNING INTERNATIONAL INC PO BOX 2405 EDMONTON, AB T5J 2S1 CANADA Fax: (780) 483-2412	ORDER DATE PAYMENT TERMS FREIGHT TERMS TRADE TERMS SHIP VIA	17-FEB-2010 NET 30 PAID DESTINATION
SHIP TO	The Yukon Electrical Company Limited **MULTIPLE LOCATIONS - SEE BELOW**	BILL TO (PURCHASER)	The Yukon Electrical Company Limited Whitehorse Office Accounts Payable 100, 1100 - 1 Avenue Whitehorse, YT Y1A 3T4 Canada PHONE 867-633-7007 FAX 867-668-6692

LINE	ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
8		TRAVEL TIME OVERTIME RETAIL RATE		HOURS	$201.25	
9		2012 SHOP STRAIGHT TIME		HOURS	$151.50	
10		2012 SHOP OVER TIME		HOURS	$206.25	
11		2012 FIELD STRAIGHT TIME		HOURS	$180.00	
12		2012 FIELD OVER TIME		HOURS	$235.50	
13		2012 TRAVEL TIME		HOURS	$151.50	

2012

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
Chocho, Michael W Mike.Chocho@atcoelectric.com	780-420-7138	780-420-7436

To report inappropriate commercial or purchasing practices, please call the following:
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Yukon Electrical
ITEK Operating Plan

Service	Volumes				Rate				Costs			
	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
Application Fees												
Dist App Storage Network Attached Disk	1,202.5	1,260.7	1,318.8	1,338.2	10.18	8.99	7.94	7.01	12,241	11,333	10,472	9,381
Financial System Disaster Recovery	12.0	12.0	12.0	12.0	288.84	296.77	299.37	301.99	3,466	3,561	3,592	3,624
Financial System Hosting & Support	12.0	12.0	12.0	12.0	5,293.82	5,344.52	5,391.27	5,438.34	63,526	64,134	64,695	65,260
Hyperion Hosting & Support	12.0	12.0	12.0	12.0	1,153.62	1,296.09	1,290.43	1,284.80	13,843	15,553	15,485	15,418
Hyperion License Maintenance	12.0	12.0	12.0	12.0	110.40	110.40	110.40	110.40	1,325	1,325	1,325	1,325
OFIN Unused License Charge	9.0	0.0	0.0	0.0	18.76	18.76	18.76	18.76	169	-	-	-
Secure Site WEB Hosting Services	12.0	12.0	12.0	12.0	165.23	165.12	164.92	164.72	1,983	1,981	1,979	1,977
Website Storage Disk	27.2	29.0	29.0	29.0	10.18	8.99	7.94	7.01	277	261	230	203
Development/Maintenance/Enhancements	285.3	146.0	40.0	40.0	109.55	109.55	109.55	109.55	31,259	15,999	4,382	4,382
Distributed Server Service												
Distributed Server Hosting - Windows T4	12.0	12.0	12.0	12.0	563.84	555.38	547.05	538.84	6,766	6,665	6,565	6,466
Distributed Server Support - Windows Gld	12.0	12.0	12.0	12.0	1,191.06	1,219.60	1,247.14	1,275.30	14,293	14,635	14,966	15,304
Mainframe												
Batch CPU Minutes	9.1	9.0	9.0	9.0	6.14	6.07	6.02	5.96	56	55	54	54
CICS CPU Minutes	781.1	818.9	856.6	869.2	5.70	5.65	5.60	5.55	4,452	4,627	4,797	4,824
DB2 CPU Minutes	4,005.2	4,199.0	4,392.8	4,457.4	5.70	5.65	5.60	5.55	22,830	23,724	24,600	24,739
Print Forms / 1000	0.4	0.5	0.5	0.5	7.58	7.58	7.58	7.58	3	4	4	4
Print Pages	0.4	0.5	0.5	0.5	44.32	45.82	47.08	48.37	19	23	24	24
TSO CPU Minutes	15.5	16.0	16.0	16.0	5.70	5.65	5.60	5.55	88	90	90	89
Financial ASP												
BI Lic Maint - BI & Back Office	11.0	12.0	12.0	12.0	48.00	48.00	48.00	48.00	528	576	576	576
BI Lic Maint - Project Analytics	11.0	12.0	12.0	12.0	35.00	35.00	35.00	35.00	385	420	420	420
Discrete Mfg Read Maint on Lic Purchase	20.0	20.0	20.0	20.0	19.10	19.10	19.10	19.10	382	382	382	382
Financials Update Maint on Lic Purchase	53.0	54.0	54.0	54.0	50.00	50.00	50.00	50.00	2,650	2,700	2,700	2,700
iExpense Maintenance on License Purchase	416.0	452.0	488.0	500.0	0.85	0.85	0.85	0.85	354	384	415	425
iProcurement Maintenance on Lic Purchase	62.0	66.0	66.0	66.0	0.89	0.89	0.89	0.89	55	59	59	59
Order Management Maint on Lic. Purchase	94.0	94.0	94.0	94.0	0.04	0.04	0.04	0.04	4	4	4	4
Project Acct Update Maint on Lic Purchse	75.0	75.0	87.0	87.0	50.00	50.00	50.00	50.00	3,750	3,750	4,350	4,350
Project Management Maint on Lic Purchase	20.0	20.0	20.0	20.0	10.60	10.60	10.60	10.60	212	212	212	212
Purchasing Update Maint. on Lic Purchase	62.0	62.0	62.0	62.0	50.00	50.00	50.00	50.00	3,100	3,100	3,100	3,100
Hardware									-	-	-	-
B & W Printer Low Volume	12.0	12.0	12.0	12.0	28.91	28.04	27.20	26.38	347	336	326	317
B & W Printer Medium Volume w/duplex	24.0	24.0	24.0	24.0	37.94	36.80	35.70	34.63	911	883	857	831
Colour Printer Low Volume	11.0	11.0	11.0	11.0	33.14	32.15	31.19	30.25	365	354	343	333
Hard Drive Encryption	112.0	108.0	108.0	108.0	5.50	5.50	5.50	5.50	616	594	594	594
Laptop H/W Operating Lease	101.0	108.0	108.0	108.0	114.21	111.93	109.69	107.50	11,535	12,088	11,847	11,610
Laptop Support High	34.0	34.0	34.0	34.0	174.93	179.12	183.16	187.30	5,948	6,090	6,227	6,368
Laptop Support Low	27.0	27.0	27.0	27.0	135.80	139.05	142.19	145.40	3,667	3,754	3,839	3,926
Laptop Support Medium	52.0	47.0	47.0	47.0	140.17	143.53	146.77	150.08	7,289	6,746	6,898	7,054
Monitor LCD - 19 inch	469.0	505.0	541.0	541.0	20.01	19.01	18.06	17.16	9,385	9,600	9,770	9,284
Monitor LCD - 22 inch	71.0	71.0	71.0	71.0	23.02	21.87	20.78	19.74	1,634	1,553	1,475	1,402
Monitor LCD - 24 inch	2.0	2.0	2.0	2.0	25.40	24.13	22.92	21.78	51	48	46	44
PC H/W Operating Lease	409.0	445.0	481.0	493.0	64.10	62.82	61.56	60.33	26,217	27,955	29,610	29,743
PC Support High	81.0	81.0	81.0	81.0	140.37	143.74	146.99	150.30	11,370	11,643	11,906	12,174
PC Support Low	168.0	168.0	168.0	168.0	116.23	119.02	121.71	124.46	19,527	19,995	20,447	20,909
PC Support Medium	160.0	196.0	232.0	244.0	119.75	122.62	125.39	128.22	19,160	24,034	29,090	31,286
Printer Support Low Volume	23.0	23.0	23.0	23.0	36.37	37.24	38.08	38.94	837	857	876	896
Printer Support Medium Volume	24.0	24.0	24.0	24.0	71.79	73.51	75.17	76.87	1,723	1,764	1,804	1,845
Process Fee	1.0	0.0	0.0	0.0	245.28	245.28	245.28	245.28	245	-	-	-
Ruggedized Laptop - Standard	12.0	12.0	12.0	12.0	130.42	127.81	125.25	122.75	1,565	1,534	1,503	1,473
SSL Secure Remote Access	13.0	13.0	13.0	13.0	31.35	30.88	30.42	29.96	408	401	395	389
VPN - Remote Client	64.0	64.0	64.0	64.0	31.35	30.88	30.42	29.96	2,006	1,976	1,947	1,917
Xerox Printer Support	36.0	36.0	36.0	36.0	71.79	73.51	75.17	76.87	2,584	2,646	2,706	2,767
Microsoft Software Assurance			30.0	41.0	-	-	262.00	262.00			7,860	10,742
Xerox												
Xerox Lease	36.0	36.0	36.0	36.0	216.37	216.37	216.37	216.37	7,789	7,789	7,789	7,789
Xerox Service	60.0	60.0	60.0	60.0	150.97	150.97	150.97	150.97	9,058	9,058	9,058	9,058
Service Request												
Express Request Service Fee	12.0	14.0	14.0	14.0	63.19	65.49	67.78	70.15	758	917	949	982
Hardware	18.0	19.0	19.0	19.0	152.13	122.49	125.76	129.12	2,738	2,327	2,389	2,453
Printer Toner / Ink	5.0	6.0	6.0	6.0	316.04	316.04	316.04	316.04	1,580	1,896	1,896	1,896
Software	10.0	10.0	11.0	11.0	434.23	434.23	434.23	434.23	4,342	4,342	4,777	4,777
Software Distribution Fee	33.0	34.0	35.0	35.0	181.83	188.45	195.05	201.87	6,000	6,407	6,827	7,065
Software Support Labour	10.5	11.0	11.0	11.0	119.20	122.49	125.76	129.12	1,252	1,347	1,383	1,420
Workstation Install/Move/Add/Chg Labour	3.0	4.0	4.0	4.0	141.76	145.16	148.44	151.79	425	581	594	607
User ID												
Blackberry Service	123.0	132.0	144.0	144.0	29.88	29.75	29.61	29.47	3,675	3,927	4,264	4,244
Citrix Terminal Server Service	38.0	38.0	38.0	38.0	40.79	40.62	40.43	40.24	1,550	1,544	1,536	1,529
Distributed Infrastructure - DR	695.0	695.0	695.0	695.0	15.58	15.52	15.45	15.38	10,828	10,786	10,738	10,689
Email Storage Service	23,147.0	30,091.1	39,118.4	50,854.0	0.83	0.71	0.61	0.52	19,212	21,365	23,862	26,444
File Server Storage Service	2,728.2	3,546.7	4,610.7	5,993.9	11.32	10.00	8.83	7.80	30,884	35,467	40,713	46,753
Instant Messaging	12.0	12.0	12.0	12.0	4.98	4.96	4.94	4.91	60	60	59	59
Internet Access Services	433.0	469.0	505.0	517.0	21.48	21.43	21.37	21.30	9,301	10,051	10,792	11,012
User ID Services	695.0	731.0	767.0	779.0	18.54	18.99	19.42	19.86	12,885	13,882	14,895	15,471
WAN												
Remote Connection Services												
VPN - Remote Branch	22.0	22.0	22.0	22.0	778.66	776.75	774.47	772.20	17,131	17,089	17,038	16,988
Wide Area Network												
VPN - Small Offices	22.0	22.0	22.0	22.0	140.55	140.20	139.79	139.38	3,092	3,084	3,075	3,066
	37,252.46	**45,394.36**	**55,941.43**	**69,227.77**	**13,891.26**	**14,104.13**	**14,452.65**	**14,542.14**	**457,965**	**462,329**	**478,480**	**493,506**

WL-YECL-14

Reference: O&M Expense, Section 5, Page 5-5

YECL is proposing to discontinue purchasing third party distribution line (property) insurance at the end of the 2013/2014 insurance period, July 1, 2014 and, on a go forward basis, insurable losses during construction or operations, if and when they occur, would be charged to the Reserve for Injuries and Damages.

Request:

(a) Please describe the nature and extent of the insurance coverage provided by the existing distribution property insurance policy. Identify the risks that are covered by the policy.

(b) Please provide an assessment of the order of magnitude maximum risk exposure if the existing policy were cancelled and replaced by self insurance.

Response:

(a) The distribution lines property insurance provides coverage on an all risks basis subject to policy terms and conditions. The loss must result from an unexpected, discrete event. The most likely causes of loss are natural catastrophe hazards such as wind, fire, and ice storms. Standard policy exclusions are faulty design, workmanship, and wear and tear.

(b) If the existing policy was cancelled and replaced by self-insurance, Yukon Electrical would no longer have $2.5 million of insurance with a $1 million deductible per occurrence.

Further to the above, and to provide perspective, the total current population of poles used by Yukon Electrical is approximately 24,000. Depending on location, ground conditions and type of pole, the replacement cost of a pole can range between $3,000 (single phase) and $8,000 (three phase). Based on this approximate range, each $1,000,000 of insurance covers the loss of between 125 and 333 poles or between 0.5% and 1.4% of Yukon Electrical's total population of poles. To fully incur the maximum risk exposure associated with discontinuing the $2,500,000, these approximations suggest Yukon Electrical would need to lose between 1.3% and 3.5% of its population of poles in a single event.

If the Board believes the risk exposure of discontinuing the insurance is too high, regardless of the probability of it occurring, Yukon Electrical has no issue with respect to continuing or changing the existing coverage. Any change in the 2014 and 2015 forecast premiums would be accounted for in Schedule 5.1 Line 40.

WL-YECL-15

Reference: Taxes Other Than Income, Section 6, Page 6-1

Increases in property taxes are due to planned capital work and inflation.

Request:

(a) Please separate the increases in the test years into tax increases due to capital projects and tax increases due to inflation.

(b) Please explain why an inflation factor is being built into property taxes during the test years when there is no apparent inflationary effect from 2008 to 2011.

Response:

(a) Please see table below showing the increases to the base level of taxes for 2012 due to inflation and new capital:

	Actual	Test Period		
	2012	**2013**	**2014**	**2015**
Base	250	250	250	250
Inflation		5	5	5
Increases Due to Capital		2	10	18
Schedule 1.1, line 11	250	257	265	273

(b) Please refer to WL-YECL-15 Attachment 1 for the City of Whitehorse 2013-2015 Operating Budget. Bylaw 2013-10 on page 30 of the Operating Budget indicates that the increases to residential and non-residential property taxes in 2013 will be 3.83%.

For the Town of Watson Lake, tax increases in 2013 for both residential and commercial properties were 3% above 2012 levels.

Please refer to UCG-YECL-22 for actual property taxes paid in 2013.

City Of Whitehorse
2013-2015
Operating Budget Package
February 25, 2013

TABLE OF CONTENTS

1. Operating Budget Overview

2. Mayor's Budget Address

3. Bylaws
    - Bylaw 2013-08 Operating Budget
    - Bylaw 2013-10 - Tax Levy

4. Important Dates and Contacts

1) Operating Budget Overview

Operations Budget 2013
Managing our City's Growth Responsibly

Whitehorse
THE WILDERNESS CITY

COMMUNITY PROFILE

- Population - 27,323
- City Size - 41,900 hectares
- Number of businesses – 1694
- Taxable Properties - 8840

BUDGET FOCUS

The focus of Operations Budget 2013:

- balancing the budget through modest tax increases and cost cutting measures
- improving services for citizens
- implementing Council's strategic priorities

BUDGET QUICK FACTS

- Balanced operating budget of $65 million
- New initiatives – expanding transit services, adding building inspector, increasing compensation for volunteer fire fighters
- Reduction in spending of $600,000
- Modest increases in residential/commercial property tax and curbside collection

BACKGROUND

- Budgets describe the City's financial state and establish spending and revenue levels for the delivery of municipal programs and services
- The City prepares two budgets annually: an operations budget and a capital budget which is enacted first
- The City divides the budgets for two reasons:
  - The budgets are easier to understand
  - By enacting the capital budget first, the City can implement capital projects at the beginning of what is a short construction season

DEFINITIONS

Operations Budget

- Respects costs that occur each year
- Salaries of staff who deliver municipal services make up a significant portion of the operations budget
- Operations budget also addresses costs related to service delivery such as facility operation and maintenance, infrastructure, equipment, water and sewer systems, vehicles, etc
- Sources of funds include property taxes, user fees, and transfers from other governments. For example, utilities services related to clean drinking water, wastewater treatment and disposal are supported by user fees

DEFINITIONS

Capital Budget

- Addresses costs related to planning and construction of municipal assets such as buildings and infrastructure (e.g. roads, recreation centres, and water and sewer pipes)
- Procurement of items used for one-time costs, with life expectancy of more than one year – equipment, vehicles, structures, systems, etc
- Capital expenditures are sourced via grants from other governments (e.g. Gas Tax, federal territorial infrastructure programs) and internal reserves

BUDGETARY CYCLE
Operations Budget

Summer

Obtain departmental submissions, begin developing budget options

Each operating department prepares a business plan setting goals and identifying resources required to achieve those goals.

Fall

Council and Senior Management work to finalize draft budget

Winter/Spring:

Feb 25: 1st reading followed by public input/committee review

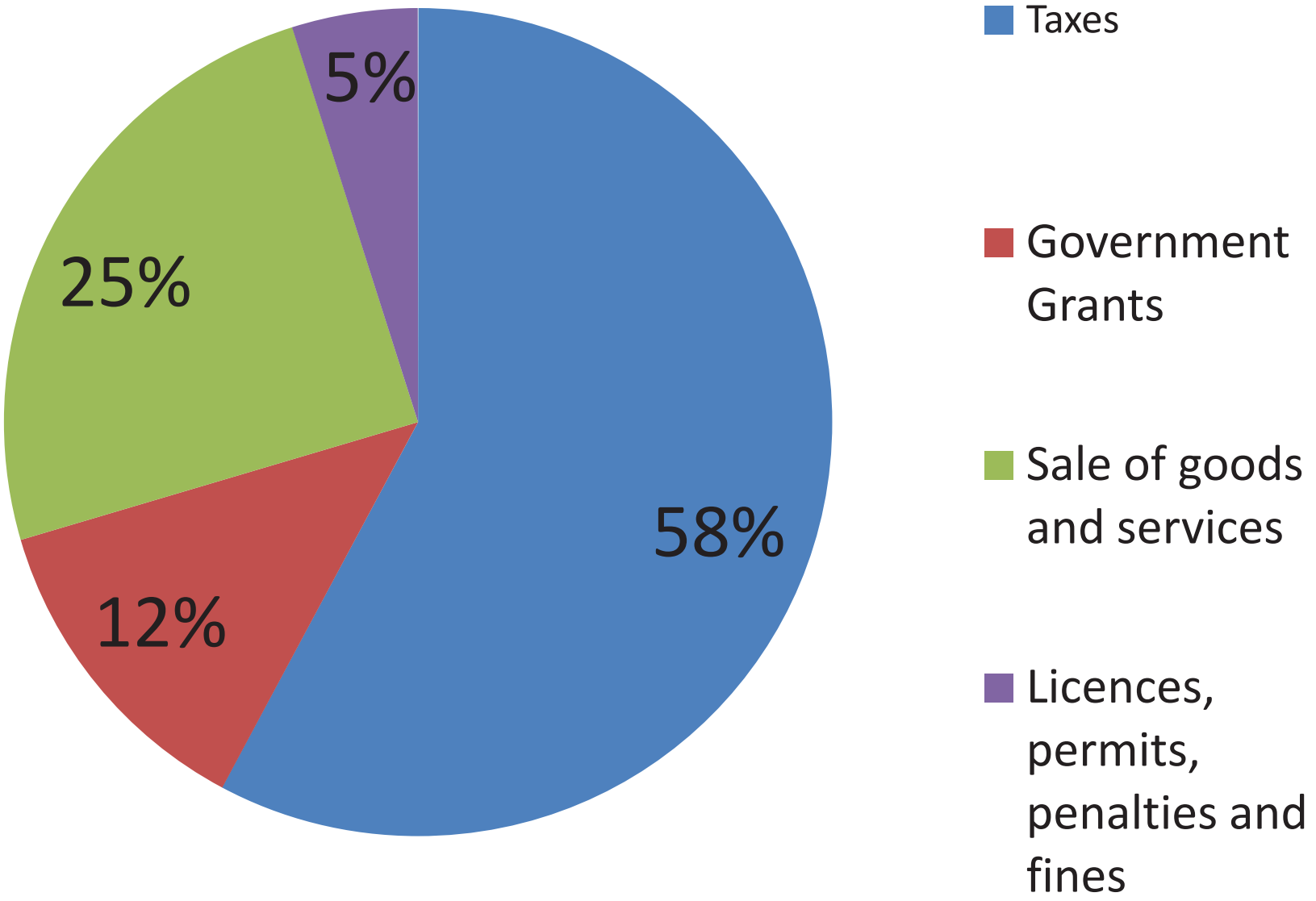
March 18: Public Input Report

March 25: 2nd/3rd reading where Council considers whether to approve budget

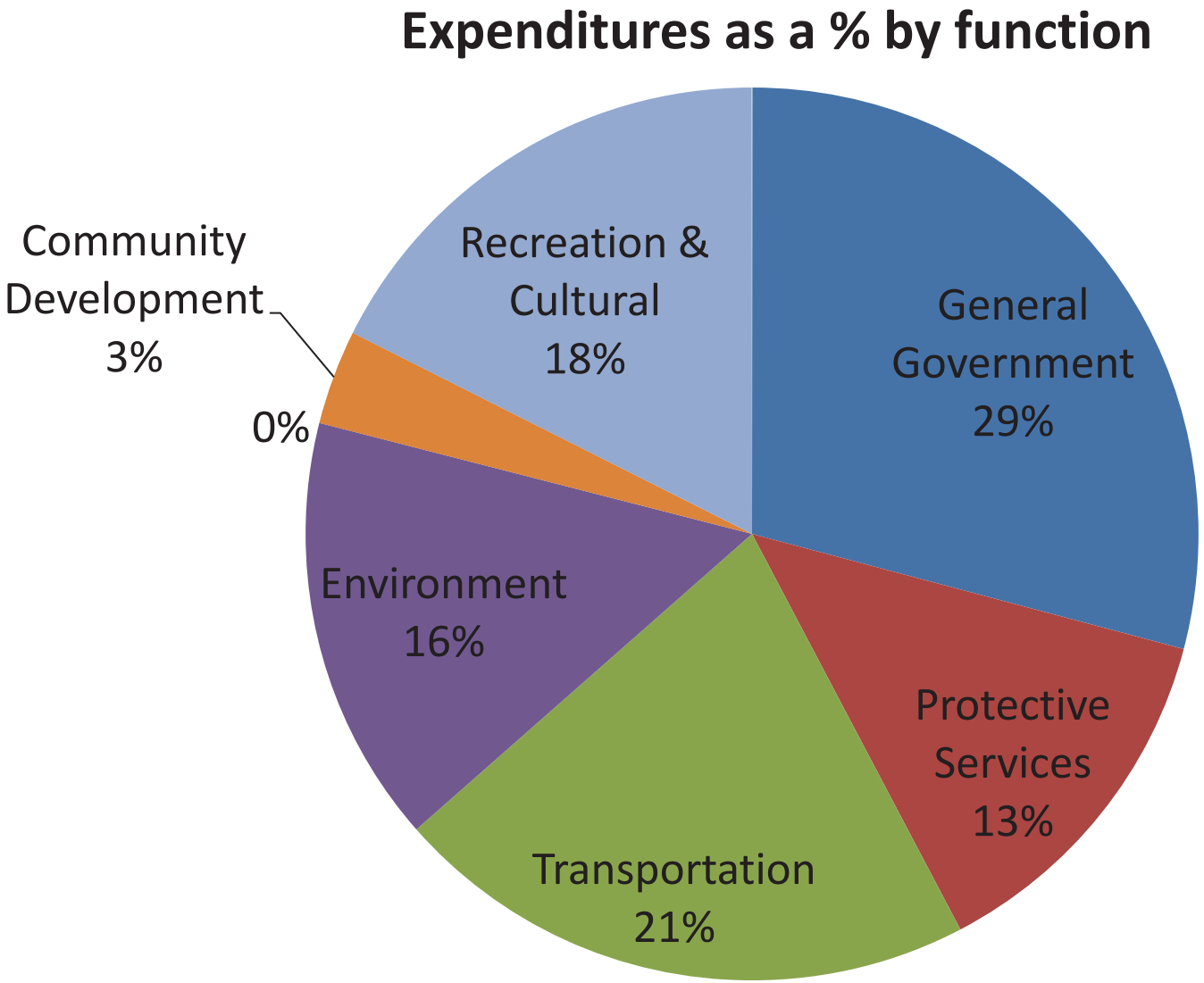
REVENUE

REVENUES	2013
Taxes and payments in lieu of taxes	$32,621,589
Government Grants	$7,096,553
Sale of goods and services	$13,920,624
Licences, permits, penalties and fines	$2,769,025
Developer Contributions	$390,000
Investment Income	$330,000
Other Revenue	$7,808,108
TOTAL	$64,935,899

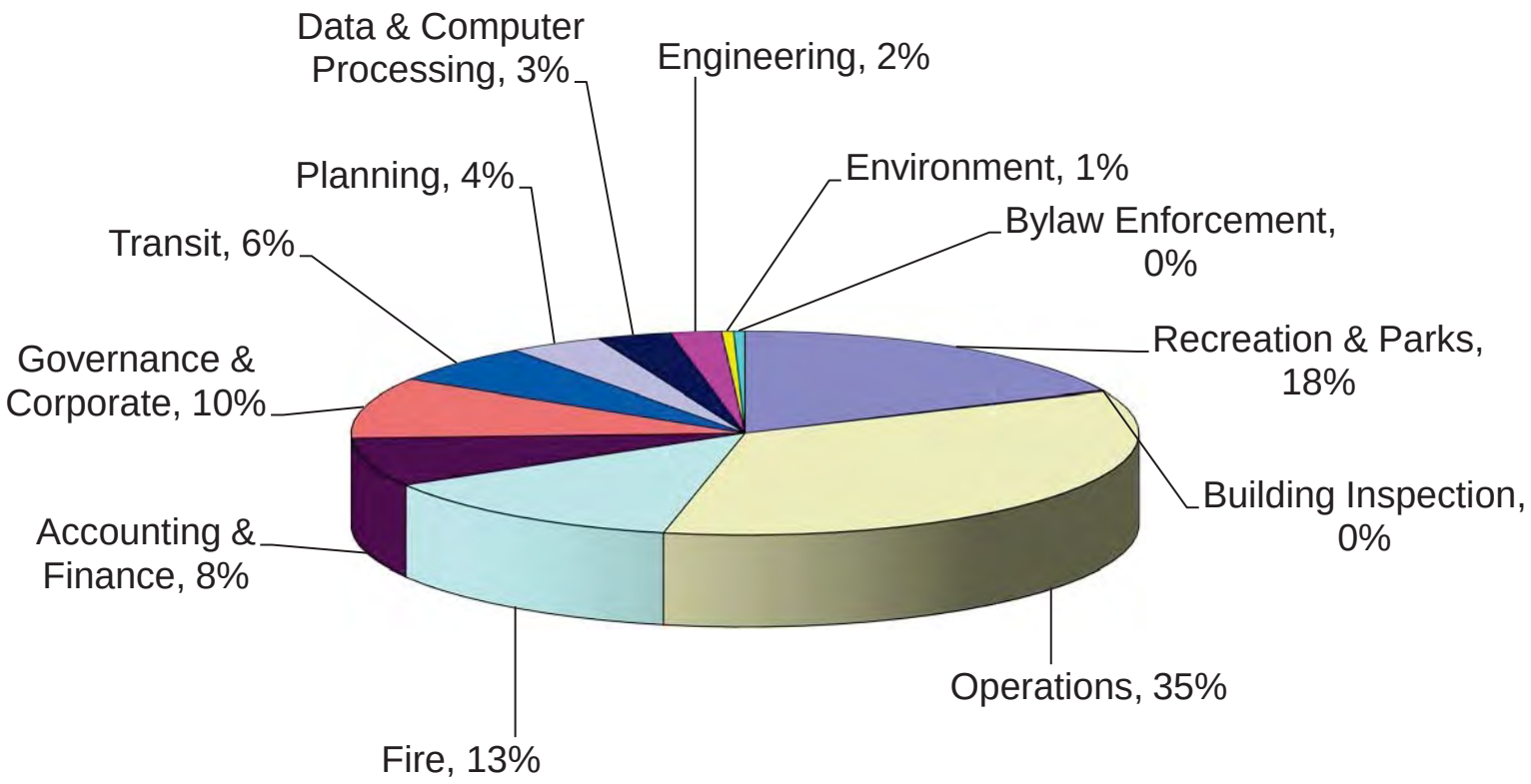
REVENUE AS A %


5%
25%
58%
12%
Taxes
Government Grants
Sale of goods and services
Licences, permits, penalties and fines

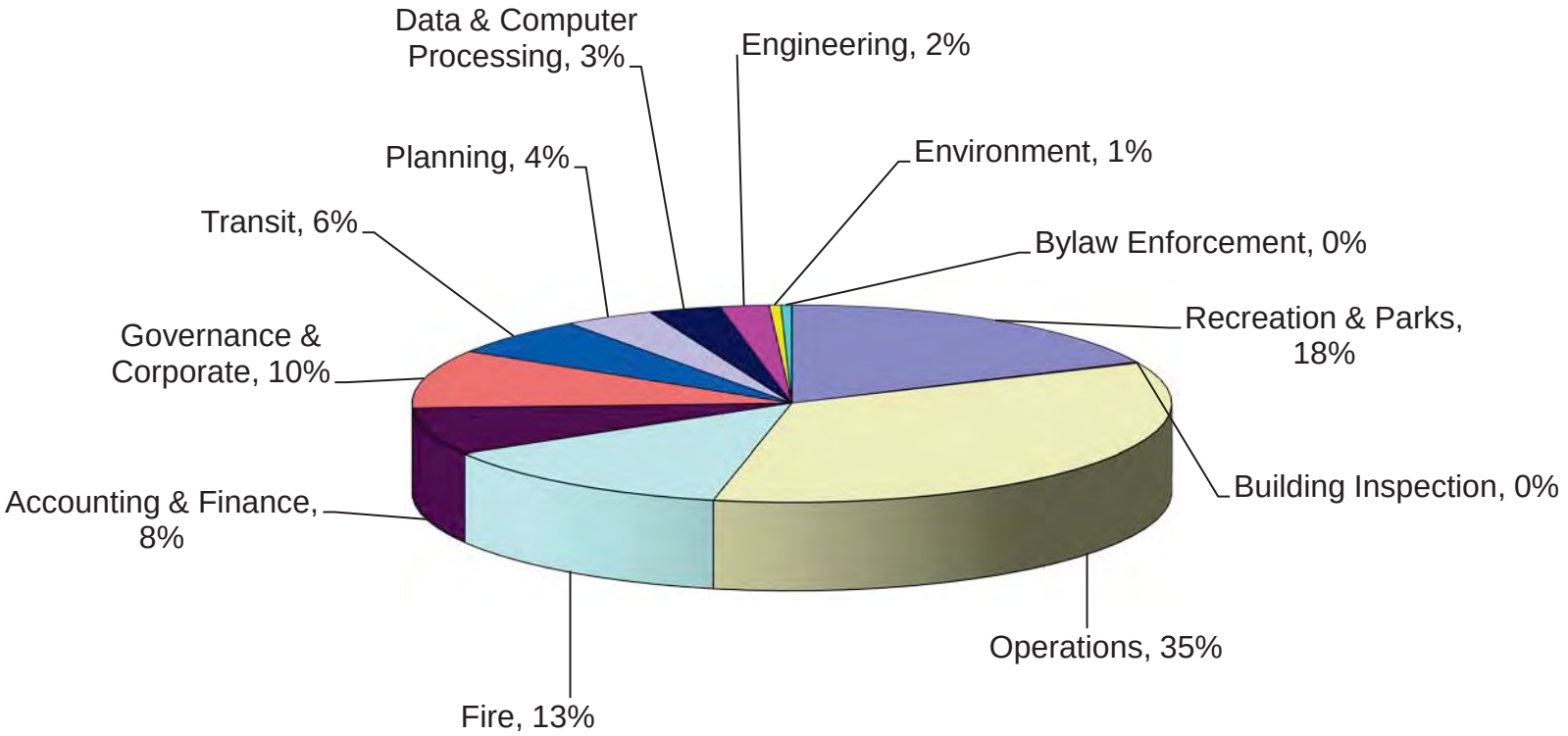
Function	Expenditures
General Government	$18,858,424
Protective Services	$8,501,070
Transportation Services	$13,728,064
Environmental Services	$10,029,522
Public Health Services	$230,591
Community Development Services	$2,219,441
Recreation & Cultural Services	$11,368,787
TOTAL	$64,935,899


Expenditures as a % by function
Community Development 3%
0%
Recreation & Cultural 18%
General Government 29%
Environment 16%
Protective Services 13%
Transportation 21%

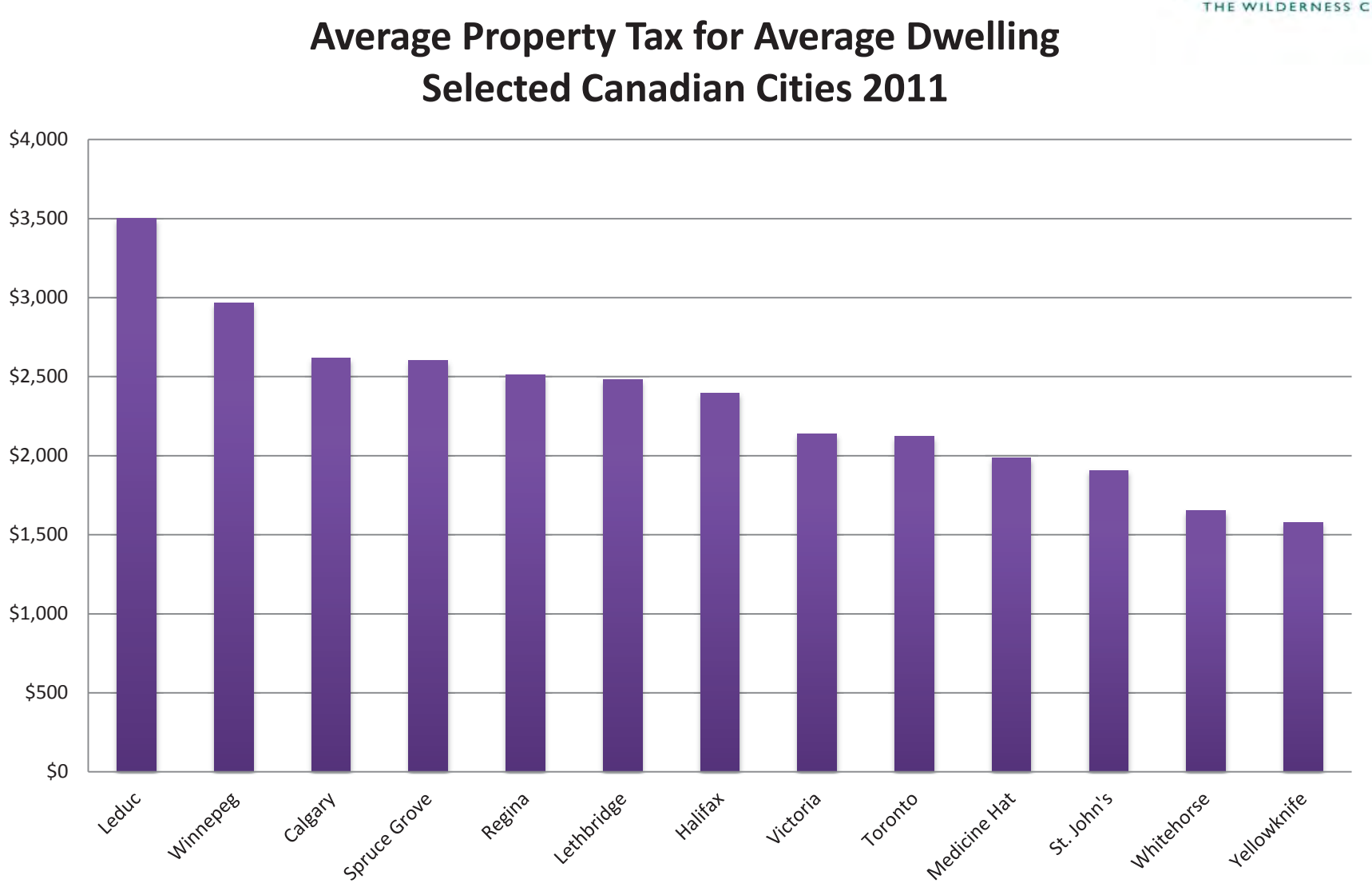
Where Does Your Tax Dollar Go?
2013 Residential Average Tax of $2,195
(Net Department Operating Costs)



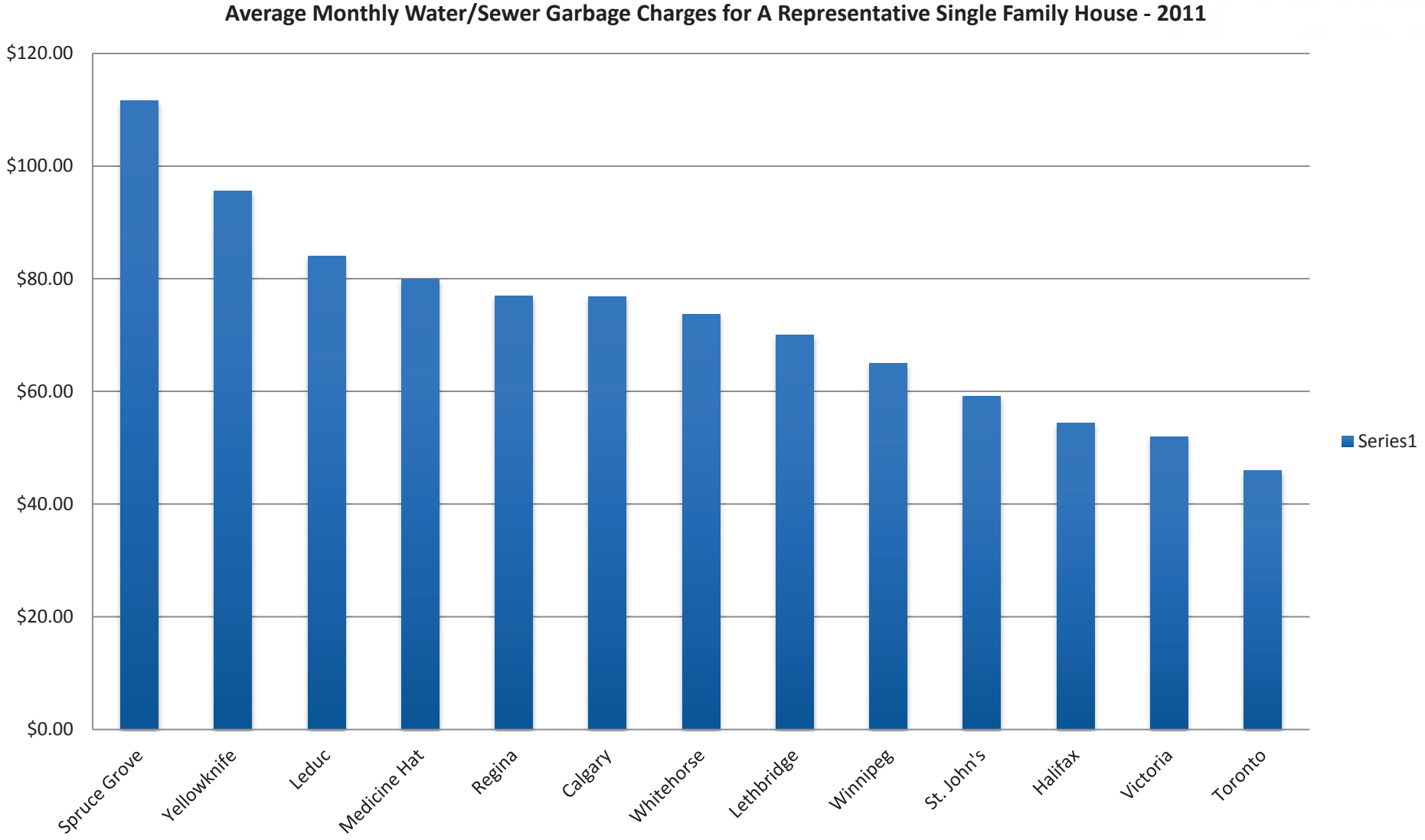
Where Does Your Dollar Go?
2013 Non-residential Average Tax of $13,795
(Net Department Operating Costs)



COMPETITIVE TAX RATES



COMPETITIVE UTILITY RATES



SERVICES FOR CITIZENS

Fire and Emergency Services

- Fire Department responded to 643 emergencies
- Fire Department responded to 156 fires
- Fire Department responded to 34 carbon monoxide alarm emergencies

City Transit

- 10 accessible low floor transit buses
- 2 handy buses
- 5 number of routes serving 150 number of stops

SERVICES FOR CITIZENS

Whitehorse
THE WILDERNESS CITY

Roads, Storm Drainage, and Watercourse

- Over 560 km of road and 120 km of sidewalks and paths
- 170 km of water pipes and 145 kilometers of sewer main

Recreation

- 35 playgrounds (Rotary Park splash park) and 50 neighbourhood parks maintained
- 100 plus recreation programs delivered annually
- 3000 visits per day to the Canada Games Centre (membership increasing monthly)

SERVICES FOR CITIZENS

Whitehorse
THE WILDERNESS CITY

Parks

- Care of 164,404 square meters of parkland and 700 kilometers of trail
- 315,000 visits to the Millennium Trail per annum

Bylaw Services – tickets issued

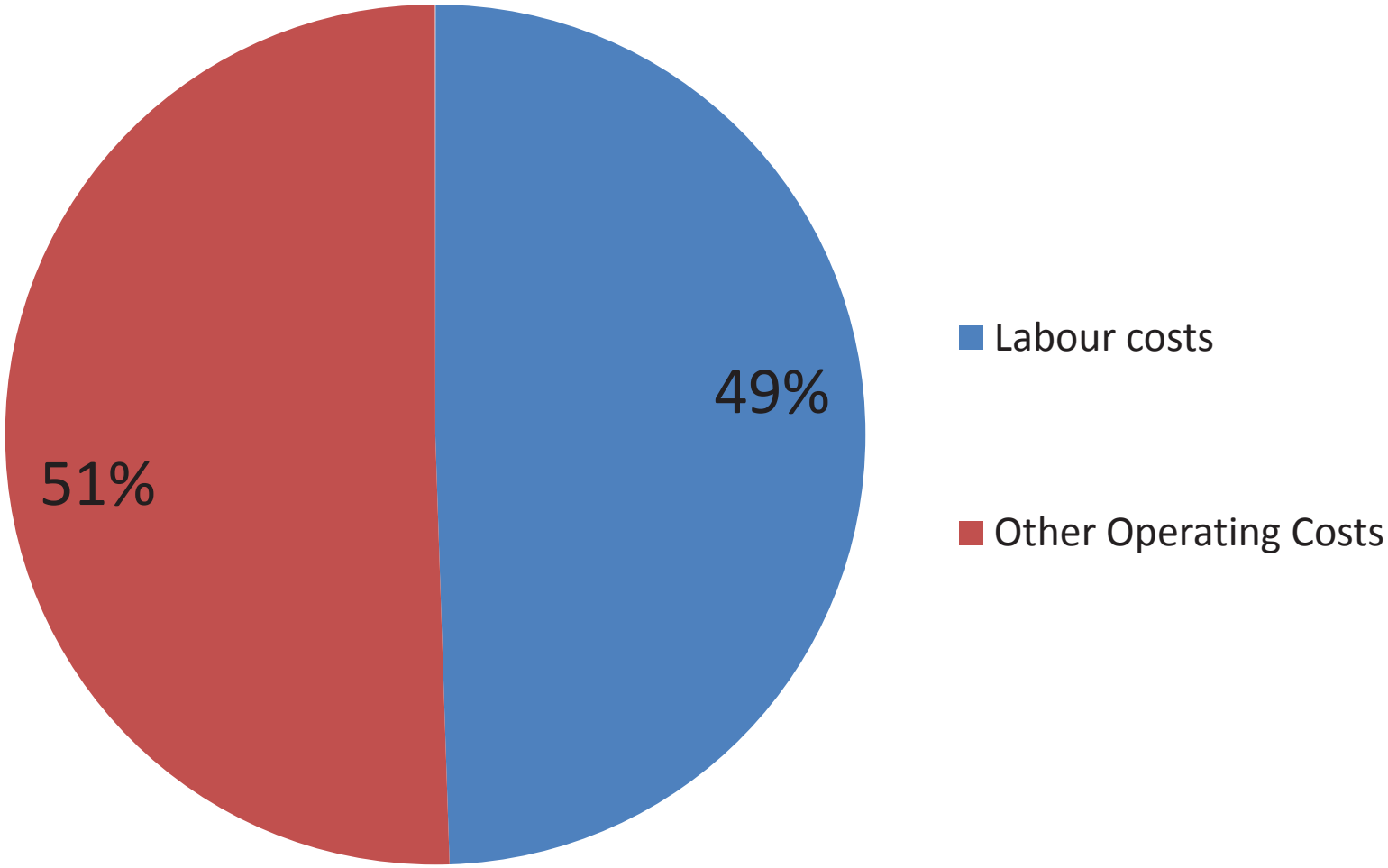
- Parking meter– 20,871
- Animal control - 209
- Accessible parking – 158
- Other - 102
- Traffic offences - 1429

WHY TAXES ARE GOING UP

Costs for delivering municipal services continue to increase due to a several factors:

- Collective agreements: collective agreements between the City and employees result in incremental salary increases
- Inflation: according to the Bureau of Statistics, the price of consumer goods (e.g. food, clothing, recreation) increased by 1.9% from December 2011 to December 2012 - 1.1% above than the national rate
- Reorganization:

People Deliver Services



NEW INITIATIVES

- Transit services expanded to provide evening service; City will work with business and Yukon College explore bus pass options
- Building Inspector will be hired to join Building Inspection Services
- Volunteer firefighters will be rewarded with an increase in remuneration

TAXES, USER FEES, TIPPING FEES

- Residential and commercial property tax to increase by 3.83%
- Residential collection (garbage/compost) to increase by $1 per month from $8 to $9
- Water & sewer remain at 2011 level
- Tipping fees for garbage to increase from $54 to $69 per metric ton while compost to increase from $0 to $26 per metric ton
- Parks & Rec. fees to increase by 1.5% as they do each year

EXPENDITURE REDUCTION PLAN

- Canada Games Centre will be closed for 6 statutory holidays instead of 2
- Scaling back snow removal for Whistle Bend until it is further developed
- Eliminating communications position
- Reducing administrative services for City Hall front desk, CGC and planning

2) Mayor's Budget Address

MAYOR'S SPEECH - OPERATIONS BUDGET 2013
MANAGING OUR CITY'S GROWTH RESPONSIBLY

INTRODUCTION

Good evening Ladies and Gentlemen. I am honoured and pleased to introduce the Operations Budget for 2013 – totalling $65 million in services for Whitehorse Citizens.

This is the first Operations Budget for this Council and follows on the heels of the 2013-2016 Capital Budget approved by Council on Monday, January 29. I would like to thank Council and our administration for assembling Operations Budget 2013.

CONTEXT

Before I get into the details of the budget and on what basis it was developed, allow me to set the context. It is clear to me that our community continues to grow. According to the Bureau of Statistics, the population of Whitehorse has increased again this year and now stands at 27,323 people. I don't think it will be much longer before we surpass the 30,000 mark.

We note that construction in our City continues at a significant rate. A trip through the City's neighbourhoods leaves one with the impression that new builds, whether we're talking about detached, semi-detached, condominiums, or multi-family units, continues at an extraordinary pace.

New developments mean an increase to the City's tax base but also require municipal services and infrastructure in the form of roads, inspections, water and sewer etc. I believe this Council has delivered an Operations Budget which responds to the City's growth and manages the challenges that accompany development of this nature.

SERVICES FOR CITIZENS

Operations Budget 2013 is about services for citizens. These services include things like:

- planning future land development opportunities;
- maintaining bridges, roads and sewer mains;
- programs such as swimming lessons, sport development and wellness programs at our recreation facilities, serving everyone from pre-schoolers to seniors;
- removing snow from our streets; and
- fire prevention and firefighting.

BUDGET HIGHLIGHTS

Operations Budget 2013 is also about new services.

Transit Services: During the last six months, we have heard from residents and people involved in the education and private sectors about expanding the City's transit services. This budget responds to these interests by offering evening hours so that our residents who work or attend class past 7pm will have a safe and inexpensive mode of transportation to get them safely to and from work or class. In addition, we intend to collaborate with Yukon College and our commercial partners to explore possibilities for employee and student bus passes.

Building Inspections: We will invest in the City's building inspection capacity. During the last 5 years, building inspection activities have increased a fair amount. I believe this is yet more evidence of our community's growth. In 2013, the City will hire a building inspector bringing the number of inspectors to 5. We think this is an important investment at a critical time given the tragic event of January 2012 and the efforts of both the City and Government of Yukon to make oil-fired appliances safer in our communities.

Volunteer Firefighters: Operations Budget 2013 rewards our hardworking volunteer firefighters who have not received an increase to the remuneration paid by the City for their services for well over five years. These are the people who work side-by-side with our firefighters to put fires out and help staff the fire-hall when our regular members are responding to emergencies. We will recognize the dedication of these volunteers with an increase to their remuneration.

BALANCED BUDGET

I am pleased to announce that this Council is tabling a balanced budget. We understand the importance of living within our means and controlling spending so that actions of this Council don't burden future Councils.

How did we achieve a balanced budget? By adopting a measured approach, involving both property tax increases and cost cutting measures, so that at the end of 2013 the City's revenues will equal its expenditures.

YOUR TAX DOLLARS

To achieve a balanced budget, the City will:

- increase residential and commercial property tax by 3.83%;
- increase curb-side garbage and compost collection fees from $8 - $9; and
- increase user fees for recreational facilities, as the City does each year, by 1.5%.

Utility rates for water and sewer will remain fixed at 2011 levels.

We recognize the importance of tax dollars the City receives from our residents and the business sector. These revenues among other sources provide the City with the resources it needs to deliver municipal services. When the City raises taxes, taxpayers expect a justification for this increase.

Let me make the case now:

Inflation: each year we are faced with inflationary pressures. Whether it is food, gas, shelter, or electricity, costs increase each year. This year is no different, with inflation reaching nearly 2% in Whitehorse or 1.1% higher than the national rate.

Salary pressures: salaries and benefits make up nearly half the operations budget. We have negotiated collective agreements with our employees that allow us to remain competitive in terms of making the City an employer of choice in what is also a competitive labour market. To attract employees who are capable and dedicated, we need to offer competitive salary and benefit packages.

City's reorganization: recently the City completed a reorganization - prepared by an independent 3rd party - focusing on how we are structured to deliver municipal services. The reorganization is a positive step forward as it ensures that we are properly aligned to meet expanding needs and greater responsibilities. This, however, requires financial support.

I think it is important to note that our tax rate, when compared to other cities in Canada, is competitive. Property tax for an average home in Whitehorse remains below the rates in cities such as St. John's, Medicine Hat, Toronto, Victoria, Halifax and Lethbridge to name but a few.

In addition, utility rates, or the rates residents pay for compost and garbage pickup and water and sewer, are on par with the rates charged in other Canadian cities.

EXPENDITURE REDUCTION PLAN

The Operations Budget, however, isn't solely about tax increases. We understand the importance of taking a responsible and balanced approach to managing the City's finances, especially when we are asking residents to contribute more.

This is why the City is implementing an expenditure reduction plan consisting of cost cutting measures today and the potential for future reductions based on a service review exercise.

We have worked closely with administration to identify a number of measures to reduce and eliminate expenditures. We anticipate that this plan will save the City approximately $600,000. Put another way, we are avoiding an additional 2% tax increase that would result if we do not implement these reductions.

This will not be a painless exercise. Certain positions will be eliminated and employees may be transferred to jobs with a higher priority. Fortunately, services for the most part will not be affected by this reduction and, of course, the safety and welfare of our citizens is paramount.

Citizens may, however, encounter slightly longer line-ups at City Hall.

In addition, we will close the Canada Games Centre for 4 additional statutory holidays, bringing the number of days the Centre is closed due to holidays to 6. This will reduce staff costs and is consistent with the hours of operation for recreation facilities in other jurisdictions.

We also intend to reduce snow removal services in Whistle Bend until that neighbourhood is more developed and the tax base has an increased.

Council and I want to mitigate any inconvenience these reductions may have on the citizens of Whitehorse. We also want to see service improvements for our residents by focusing on how we do things at the City.

Council and I have, therefore, directed Mr. Westby, our City Manager, to commence a full review of all City services. Mr. Westby has been given a tall order – examine the services offered by the City to determine how we can save the City money and improve services to meet the needs of our citizens and the City. This is a Council priority.

AFFORDABLE AND DIVERSE HOUSING

Another priority of this Council has to do with the City's housing supply. In the last number of years, housing has been a preoccupation at all levels of government and for good reason.

We intend to continue working with our industry partners, the Government of Yukon, and the Whitehorse Chamber of Commerce – which I note is doing an admirable job of keeping this important issue on everyone's agenda.

As I noted previously, residential development in our City's neighbourhoods continues with new construction going up throughout the City. These include both private and public developments like: Brookside 34 units, Central Park 25 units, and Crocus Glen 35 units. There is also Whistle Bend with 3500 units. Our hope is that these developments will begin to soften housing prices in Whitehorse, making it easier for people to enter the housing market.

The City, however, should not, indeed cannot, afford to be complacent. We readily acknowledge that our economic future is tied to the natural resource extraction sector which will likely drive the territory forward for the foreseeable future. If the City is to do its part to ensure we are positioned to reap the full benefits of natural resource extraction, we must begin planning for this eventuality now.

This means examining areas in our City, such as the City's south or the Tank Farm, which could be suitable locations for the next Copper Ridge or Whistle Bend. It also means proactively working with the Government of Yukon and the First Nation governments of the Kwänlin Dun and Ta'an Kwäch'än, governments with land in strategic locations throughout the City, to identify the next area for land development.

In addition, we will be looking to new technologies, such as district heating sources, for future subdivisions as a way of reducing the City's carbon footprint and to relieve pressure on the Yukon power grid.

IMPROVING WASTE MANAGEMENT

Not all aspects of our City's growth have been favourable.

Here I am talking primarily about the waste generated by construction but also the choices that people make at the checkout. Between 2000 and 2011, the waste generated by the City's residents has increased by 85%. During this same period, the amount of waste diverted from the waste management facility has failed to keep pace.

In other words, we continue to produce more and more waste but we are not significantly increasing the amount of waste we divert from the waste management facility. The increase in waste puts direct pressure on the life of the landfill.

This has costs. A recent independent assessment of the City's waste management facility concluded that it has 41 years as opposed to 78 years left before it becomes completely full. What this means for the City and its residents is that we have much less time to prepare for the decommissioning of the waste management facility. This has a projected cost of $13.5 million in today's dollars.

The assessment also recommended that the City change how it records its costs based on the expansion of the diversion services the City offers. To a certain extent, general revenues are presently being used to offset part of the City's waste management costs – contrary to Council policy – which are meant to be addressed entirely on a cost recovery basis.

We are, therefore, adopting two measures to address this priority area:

1. First, we will increase user fees for garbage, compost and recycling to reflect the true cost of municipal waste management services, and we will prepare for decommissioning of the waste management facility by increasing the annual contributions to the capital reserve;

2. Second, we will introduce a Solid Waste Action Plan in the near future. The goal of this plan will be to maximize waste diversion and minimize waste generation as we move forward on the path toward zero waste. Council will be seeking public feedback during the development of this plan.

CONCLUSION

To summarize, Council is seeking to establish an operations budget which will manage taxpayer contributions in a responsible manner, consisting of

- modest tax increases;
- combined with targeted strategic increases in services, most important of which is transit;
- spending reductions;
- with a minimal reduction in services.

We are also looking to implement our strategic priorities by:

- taking action to improve services for citizens,
- improving our waste management services through enhanced activity reporting and the implementation of a waste diversion strategy, and
- taking action to contribute to the conditions necessary for diverse and affordable housing to emerge.

I believe we are on the way to accomplishing these objectives with Operations Budget 2013.

Thank you.

3) Bylaws

CITY OF WHITEHORSE

BYLAW 2013-08

A bylaw to adopt the 2013 Annual Operating and Maintenance Budget, and the 2014 and 2015 Provisional Budgets

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WHEREAS section 238 of the *Municipal Act* (R.S.Y. 2002) provides that council shall by bylaw cause an annual operating budget to be prepared and adopted; and;

WHEREAS section 239 of the *Municipal Act* provides that council may establish by bylaw a procedure to authorize and verify expenditures that vary from the annual operating expenditure program;

NOW THEREFORE the Council of the municipality of the City of Whitehorse in open meeting assembled HEREBY ENACTS AS FOLLOWS:

1. The 2013 Annual Operating and Maintenance Budget and the Provisional Budgets for 2014 and 2015, attached hereto as Appendix "A" and forming part of this bylaw, is hereby adopted.

2. No expenditure may be made that is not provided for in the 2013 Annual Operating Budget unless such expenditure is approved as follows:

   (1) By the Director of Administrative Services to a maximum expenditure of $20,000.00 only; or

   (2) By resolution of Council to a maximum expenditure of $500,000.00; or

   (3) By bylaw for expenditures in excess of $500,000.00.

3. No expenditures shall be made which increase total expenditures above what is approved in the 2013 Operating and Maintenance Budget unless the expenditure is approved by bylaw.

4. Expenditures authorized in accordance with section 2 hereof that result in an increase in total expenditures above what was approved in the Operating and Maintenance Budget may be subsequently approved through an umbrella bylaw at year end.

5. This bylaw shall come into full force and effect upon the final passing thereof.

FIRST READING: February 25, 2013
PUBLIC NOTICE:
PUBLIC INPUT:
SECOND READING:
THIRD READING & ADOPTION:

_____
Mayor

_____
City Clerk

City of Whitehorse

2013 - 2015 Operating Budget

Revenues

Appendix A

	2012	2013	2014	2015
	Revised Budget	Budget	Provisional	Provisional
01 General Government				
City Manager	-10,000			
Community & Recreation Services	-10,000			
Development Services	-10,000			
Infrastructure & Operations	-163,550			
Engineering & Capital Projects	-221,004	-136,500	-136,500	-136,500
Financial Services	-42,286,159	-43,211,336	-44,118,337	-43,942,964
Human Resources		-8,800	-8,800	-8,800
Business & Information Technology Services	-1,000	-1,000	-1,000	-1,000
Legislative & Administrative Services	-75,898	-500	-500	-54,000
Strategic Communications		-20,000	-20,000	-20,000
Total Revenues	**-42,777,611**	**-43,378,136**	**-44,285,137**	**-44,163,264**
02 Protective Services				
Building Inspection	-721,430	-763,150	-763,150	-763,150
Bylaw Services	-1,825,225	-1,815,775	-1,815,775	-1,915,775
Financial Services	-25,000	-25,000	-25,000	-25,000
Fire & Emergency Services	-15,200	-66,000	-66,000	-66,000
Total Revenues	**-2,586,855**	**-2,669,925**	**-2,669,925**	**-2,769,925**
03 Transportation Services				
Financial Services	-2,370,409	-2,736,392	-2,736,392	-2,736,392
Operations	-759,319	-420,082	-420,073	-375,500
Transit Services	-1,499,000	-1,134,577	-1,192,069	-1,194,157
Water & Waste Services				
Total Revenues	**-4,628,728**	**-4,291,051**	**-4,348,534**	**-4,306,049**
04 Environmental Services				
Environmental Sustainability	-125,000	-300,770	-304,217	-125,000
Financial Services	-62,000	-62,000	-62,000	-62,000
Water & Waste Services	-8,976,008	-9,755,414	-10,199,751	-10,304,237
Total Revenues	**-9,163,008**	**-10,118,184**	**-10,565,968**	**-10,491,237**
05 Public Health Services				
Parks & Trails	-73,737	-74,587	-74,587	-74,587
Total Revenues	**-73,737**	**-74,587**	**-74,587**	**-74,587**
06 Community Development Services				
Planning Services	-877,755	-765,406	-769,429	-597,767
Recreation & Facility Services	-3,000			
Economic Development	-20,000			
Total Revenues	**-900,755**	**-765,406**	**-769,429**	**-597,767**
07 Recreation & Cultural Services				
Outreach & Events	-323,220	-242,928	-242,928	-242,928
Parks & Trails	-68,127	-87,300	-87,300	-87,300
Recreation & Facility Services	-2,903,372	-3,308,382	-3,148,281	-3,148,281
Total Revenues	**-3,294,719**	**-3,638,610**	**-3,478,509**	**-3,478,509**
Total	**-63,425,413**	**-64,935,899**	**-66,192,089**	**-65,881,338**

City of Whitehorse

2013 - 2015 Operating Budget

Expenses

Appendix A

	2012	2013	2014	2015
	Revised Budget	Budget	Provisional	Provisional
01 General Government				
City Manager	363,788	382,169	391,329	400,536
Community & Recreation Services	10,000	254,731	261,323	267,482
Corporate Services	318,447	288,512	282,604	276,262
Development Services	10,000	255,131	261,662	267,761
Infrastructure & Operations	456,547	254,916	261,447	267,546
Engineering & Capital Projects	990,048	919,793	943,157	958,904
Financial Services	12,923,186	12,295,310	11,094,144	10,229,660
Human Resources	967,999	1,066,861	1,170,709	1,135,099
Business & Information Technology Services	1,113,670	1,150,703	1,170,449	1,184,903
Legislative & Administrative Services	895,642	668,755	802,376	861,467
Operations	1,342,135	1,071,136	1,080,467	1,086,885
Strategic Communications		250,407	245,296	248,526
Total Expenses	**19,391,462**	**18,858,424**	**17,964,963**	**17,185,031**
02 Protective Services				
Development Services				
Building Inspection	627,224	677,821	737,871	747,496
Bylaw Services	1,555,507	1,641,830	1,646,410	1,684,381
Fire & Emergency Services	4,918,831	5,006,440	5,357,161	5,711,679
Human Resources	219,032	213,655	212,250	214,002
Operations	904,693	961,324	962,723	963,685
Total Expenses	**8,225,287**	**8,501,070**	**8,916,415**	**9,321,243**
03 Transportation Services				
Operations	9,628,586	10,254,421	10,918,537	10,991,984
Transit Services	3,431,288	3,473,643	3,736,551	3,759,651
Water & Waste Services				
Total Expenses	**13,059,874**	**13,728,064**	**14,655,088**	**14,751,635**
04 Environmental Services				
Environmental Sustainability	293,370	487,846	442,444	302,589
Operations	165,681	155,278	155,978	156,459
Parks & Trails	46,780	46,597	47,088	47,419
Water & Waste Services	8,611,596	9,339,801	9,829,078	9,891,033
Total Expenses	**9,117,427**	**10,029,522**	**10,474,588**	**10,397,500**
05 Public Health Services				
Operations	1,000	1,000	1,000	1,000
Parks & Trails	214,566	229,591	249,065	258,293
Total Expenses	**215,566**	**230,591**	**250,065**	**259,293**
06 Community Development Services				
Development Services		4,658	4,658	4,658
Planning Services	2,166,949	2,214,783	2,395,029	2,323,125
Recreation & Facility Services	49,300			
Economic Development	394,455			
Total Expenses	**2,610,704**	**2,219,441**	**2,399,687**	**2,327,783**
07 Recreation & Cultural Services				
Operations	1,140,361	1,125,539	1,136,736	1,144,448
Outreach & Events	1,022,131	883,243	878,814	898,117
Parks & Trails	1,591,034	1,840,333	1,924,055	1,924,647
Recreation & Facility Services	7,051,567	7,519,672	7,591,678	7,671,641
Total Expenses	**10,805,093**	**11,368,787**	**11,531,283**	**11,638,853**
Total	**63,425,413**	**64,935,899**	**66,192,089**	**65,881,338**

CITY OF WHITEHORSE

BYLAW 2013-10

EXPLANATORY NOTES

The attached bylaw sets out the 2013 tax rates.

	2009	2010	2011	2012	2013
Agricultural	1.090	1.078	1.121	1.164	1.209
Non-Residential	1.638	1.619	1.684	1.675	1.739
Residential:	1.193	1.179	1.227	1.135	1.178

Total 2013 tax revenue (Residential and Non-Residential) increased by 3.83%

Average Residential Property (RSC, RS1, RR1 and RS2)

Assessment	2009	2010	2011	2012	2013
Improvements	$100,045	$112,419	$113,451	$123,594	$124,671
Land	$57,133	$57,944	$57,850	$64,116	$61,637
Total Assessed Value	$157,178	$170,362	$171,301	$187,711	$186,308
TAX LEVY	$1,875	$2,009	$2,101	$2,130	$2,195

CITY OF WHITEHORSE

BYLAW 2013-10

A bylaw to levy taxes for the year 2013

WHEREAS section 55(2) of the *Assessment and Taxation Act* requires that each municipality shall levy taxes upon all taxable real property within its jurisdiction; and

WHEREAS section 55(3) of the *Assessment and Taxation Act* provides for the establishment of different classes of real property, and varied tax rates according to the class of real property to be taxed;

NOW THEREFORE the Council of the municipality of the City of Whitehorse, in open meeting assembled, hereby ENACTS AS FOLLOWS:

1. In this bylaw,

   "Agricultural" means all property used primarily for agricultural purposes and designated on the Whitehorse Assessment Roll as AGR.

   "Non-Residential" means all property used primarily for commercial, industrial and public purposes and designated on the Whitehorse Assessment Roll as CH, CMC, CMH, CML, CR, CMS, INS, MHI, MSI, PRC and QRY.

   "Residential" means all property used primarily for residential use and designated on the Whitehorse Assessment Roll as OSP, POS, REC, RMH, RR1, RSA, RSC, RSM, RS1, RS2 and TRA.

2. A general tax for the year 2013 shall be levied upon all taxable real property in the City of Whitehorse classified "agricultural" at the rate of one point two zero nine percent (1.209%).

3. A general tax for the year 2013 shall be levied upon all taxable real property in the City of Whitehorse classified "non-residential" at the rate of one point seven three nine percent (1.739%).

4. A general tax for the year 2013 shall be levied upon all taxable real property in the City of Whitehorse classified "residential" at the rate of one point one seven eight percent (1.178%).

5. This bylaw shall come into full force and effect upon the final passing thereof.

FIRST READING:
SECOND READING:
THIRD READING and ADOPTION:

_____
Mayor

_____
City Clerk

4) Important Dates and Contacts

Important Dates

February 25, 2013 - 1st Reading of:

- Bylaw 2013-08 Operating Budget
- Bylaw 2013-10 Tax Levy

March 11, 2013 – Public Input night at Council 7:30 pm at City Hall

March 18, 2013 – Report on Public Input

March 25, 2013 – 2nd and 3rd Reading of:

- Bylaw 2013-08 Operating Budget
- Bylaw 2013-09 Fees & Charges
- Bylaw 2013-10 Tax Levy

Contacts

Public Input e-mail: budgetinput@whitehorse.ca

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- Phone (867) 334-2122

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- valerie.anderson@whitehorse.ca
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Lindsay Schneider – Budget/Internal Audit Specialist

- lindsay.schneider@whitehorse.ca
- Phone (867) 334-3404

WL-YECL-16

Reference: Return on Equity, Section 8, Page 8-6

YECL is seeking approval for a deferral account that would flow through any change in its ROE according to the BCUC Automatic Adjustment Mechanism, which will become operative if a long term Canada bond yield of 3.8% is met or exceeded.

Request:

(a) Please describe the rationale for and functioning of the AAM. How is the change in the ROE linked to the magnitude of the change in bond yields? Please explain the linkage to a long term Canada bond yield of 3.8% for activating the AAM. Is there a cap on the frequency and magnitude of the AAM changing the ROE to prevent numerous and excessive increases in the ROE?

(b) Using YECL's 2015 forecast long term bond rate range of 4.0% to 4.4%, what would be the range of adjustments to YECL's ROE through the AAM? What would be the revenue range collected through the proposed deferral account and the impact in a $/kwh and rate percent increase basis for the different customer classes?

(c) Is the AAM reversible? For example, if the bond rate dropped to or below some threshold, would the AAM decrease YECL's approved ROE? If yes, what is that lower bond yield threshold? If no, please explain why not? Why it is fair and reasonable for the AAM to be able to increase the ROE but not decrease it?

Response:

(a) As per page 88 of the May 10, 2013 BCUC GCOC Decision, the rationale for the AAM is provided below:

> …the application of the AAM has the potential to contribute to regulatory efficiency. Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the

standard than taking no consideration of changes in the market over a three year period as suggested by FBCU.

Fifty percent of the change in the Long Canada Bond Forecast will be reflected in the change to the ROE.

Page 91 of the May 10, 2013 BCUC GCOC Decision discussed the long Canada bond yield floor of 3.8%. The excerpt is provided below.

> With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.

With respect to frequency, the AAM is expected to be applied annually. The BCUC GCOC Decision does not prescribe any magnitude restrictions.

(b) The basic adjustment formula provided on Page 90 of the May 10, 2013 BCUC GCOC Decision regarding the Generic Cost of Capital Proceeding is as follows:

> ROE_1 = Base ROE (8.75%) + 0.50 x ($LCBF_t$ – BaseLCBF) + 0.50 x ($UtilBondSpread_t$ – BaseUtilBondSpread)
>
> Where:
>
> $LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.
>
> $UtilBondSpread_t$ is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

Based on Yukon Electrical's forecast long term bond rate range of 4.0% to 4.4%, and assuming that there is no change in the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields, the range of adjustments to Yukon Electrical's ROE through the AAM would be 0.1% to 0.3% (ROE of 9.31% to 9.51%).

In the case of a 0.1% increase to the ROE, additional revenue collected through the AAM would be $54,000 for 2014 and $60,000 for 2015. Please refer to WL-YECL-16(b) Attachment 1 for the calculation. The impact would be a $0.0001/kWh and the cumulative rate increase over existing rates for all customer classes would be 9.6% through to 2014 (9.5% in the Application) and 11.8% through to 2015 (11.7% in the Application).

In the case of a 0.3% increase to the ROE, additional revenue collected through the proposed deferral account would be $161,000 for 2014 and $181,000 for 2015. Please refer to WL-YECL-16(b) Attachment 1 for the calculation. The impact would be $0.0004/kWh and the cumulative rate increase over existing rates for all customer classes through to 2014 would be 9.8% (9.5% in the Application) and 12.0% for 2015 (11.7% in the Application).

(c) As noted above, the BCUC determined that any change in the ROE resulting from the AAM formula is subject to an actual long Canada bond yield of

3.8% being met or exceeded so as to deal with downward bias in the AAM formula. Provided this condition is met, the change in the ROE determined by the AAM formula may be positive or negative depending on the combined change in the Long Canada Bond Forecast and Utility Bond Spreads.

The Yukon Electrical Company Limited
Impact of the AAM on ROE and Revenue Requirement

Impact on Revenue Requirement of 0.1% Increase in Return on Equity

	Source	2014	2015	
Mid Year Rate Base ($000s)	Schedule 8.1 of Application	86,063	96,812	(a)
Common Stock Ratio	Schedule 8.1 of Application	43.66%	43.70%	(b)
Change in ROE Due to AAM		0.1%	0.1%	(c)
Tax Rate	Schedule 10.1 of Application	30%	30%	(d)
Change in Revenue Requirement ($000s)		**54**	**60**	**(a) x (b) x (c) / (1-(d))**

Impact on Revenue Requirement of 0.3% Increase in Return on Equity

	Source	2014	2015	
Mid Year Rate Base ($000s)	Schedule 8.1 of Application	86,063	96,812	(a)
Common Stock Ratio	Schedule 8.1 of Application	43.66%	43.70%	(b)
Change in ROE Due to AAM		0.3%	0.3%	(c)
Tax Rate	Schedule 10.1 of Application	30%	30%	(d)
Change in Revenue Requirement ($000s)		**161**	**181**	**(a) x (b) x (c) / (1-(d))**

WL-YECL-17

Reference: Common Equity Ratio, Section 8, Page 8-4 and 8-6

YECL refers to its expert evidence from its previous GRA which stated that YECL's business risk is similar to NUL(YK). In the time since, NUL(YK)'s common equity ratio has increased from 40% to 43.5%.

In the previous GRA, the YUB approved a common equity ratio of 40%. In the time since the BCUC has increased its benchmark common equity ratio from 35.01% to 38%.

Request:

(a) With the NUL(YK) and the BCUC common equity ratios both having been increased by 3.5%, please explain why YECL is seeking a common equity ratio of 44% rather than the 43.5% that would be in keeping with the 3.5% increases in the NWT and BC.

(b) Please provide a calculation of YECL's coverage ratios including before and after tax interest coverage ratios, funds from operations to interest coverage ratios, funds from operations to debt ratios, for the 2008 and 2009 GRA forecasts and actuals, the 2010 to 2012 actuals as well as for the 2013 to 2015 GRA forecasts.

Response:

(a) Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(b) Please refer to WL-YECL-17(b) Attachment 1for the ratio calculations.

Yukon Electrical notes the results are consistent with the ratios calculated in NWTPUB Decision 24-2008 and Decision 25-2008 when the NWT Board approved common equity ratios of 43.5% and 44% for Northland (Yellowknife) and Northland (NWT), respectively. The ratios calculated by the Board in Table 3 of the above noted decisions were as follows:

	2008	2009	2010
Northland (Yellowknife)			
Decision 24-2008			
Interest Coverage	2.38	2.55	2.51
FFO interest Coverage	4.0	4.2	4.2
Northland (NWT)			
Decision 24-2008			
Interest Coverage	2.53	3.35	3.29
FFO interest Coverage	4.5	5.6	5.6

The Yukon Electrical Company Limited
Credit Metrics 2008-2009 GRA

2008 GRA Approved

	2008 GRA Approved				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	26,621	59.11%	6.87%	4.06%	4.06%
Common Stock Equity	17,747	39.41%	9.08%	3.58%	5.46%
No Cost Capital	669	1.49%	0.00%	0.00%	0.00%
	45,037	100.00%		7.64%	9.52%
Net Rate Base (excl WIP)	46,090				
Depreciation	2,391				
Interest Coverage Ratio					2.35
FFO/Debt				15%	
FFO Interest Coverage				3.23	
Debt/Capital				59%	

2009 GRA Approved

	2009 GRA Approved				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	29,730	59.17%	6.60%	3.91%	3.91%
Common Stock Equity	19,820	39.45%	8.92%	3.52%	5.33%
No Cost Capital	695	1.38%	0.00%	0.00%	0.00%
	50,245	100.00%		7.43%	9.24%
Net Rate Base (excl WIP)	49,478				
Depreciation	2,633				
Interest Coverage Ratio					2.36
FFO/Debt				15%	
FFO Interest Coverage				3.21	
Debt/Capital				59%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2008 Actual

	2008 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	24,575	56.81%	6.97%	3.96%	3.96%
Common Stock Equity	17,994	41.59%	7.03%	2.93%	4.47%
No Cost Capital	693	1.60%	0.00%	0.00%	0.00%
	43,262	100.00%		6.88%	8.42%
Net Rate Base (excl WIP)	45,946				
Depreciation	2,201				
Interest Coverage Ratio					2.13
FFO/Debt				14%	
FFO Interest Coverage				3.13	
Debt/Capital				57%	

2009 Actual

	2009 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	27,650	57.34%	6.73%	3.86%	3.86%
Common Stock Equity	19,866	41.20%	11.35%	4.67%	7.08%
No Cost Capital	702	1.45%	0.00%	0.00%	0.00%
	48,217	100.00%		8.53%	10.94%
Net Rate Base (excl WIP)	49,116				
Depreciation	2,313				
Interest Coverage Ratio					2.84
FFO/Debt				17%	
FFO Interest Coverage				3.50	
Debt/Capital				57%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2010 Actual

	2010 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	29,950	57.27%	6.58%	3.77%	3.77%
Common Stock Equity	21,682	41.46%	10.54%	4.37%	6.52%
No Cost Capital	666	1.27%	0.00%	0.00%	0.00%
	52,298	100.00%		8.14%	10.29%
Net Rate Base (excl WIP)	50,026				
Depreciation	2,462				
Interest Coverage Ratio					2.73
FFO/Debt				16%	
FFO Interest Coverage				3.32	
Debt/Capital				57%	

2011 Actual

	2011 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	32,450	57.36%	6.42%	3.68%	3.68%
Common Stock Equity	23,472	41.49%	10.74%	4.46%	6.51%
No Cost Capital	649	1.15%	0.00%	0.00%	0.00%
	56,571	100.00%		8.14%	10.19%
Net Rate Base (excl WIP)	52,408				
Depreciation	2,840				
Interest Coverage Ratio					2.77
FFO/Debt				16%	
FFO Interest Coverage				3.41	
Debt/Capital				57%	

The Yukon Electrical Company Limited
Credit Metrics 2008-2012 Actual

2012 Actual

	2012 Actual				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	36,950	58.35%	6.16%	3.59%	3.59%
Common Stock Equity	25,740	40.65%	10.18%	4.14%	5.91%
No Cost Capital	631	1.00%	0.00%	0.00%	0.00%
	63,321	100.00%		7.73%	9.51%
Net Rate Base (excl WIP)	60,033				
Depreciation	2,821				
Interest Coverage Ratio					2.64
FFO/Debt				14%	
FFO Interest Coverage				3.28	
Debt/Capital				58%	

The Yukon Electrical Company Limited
Credit Metrics 2013-2015 Forecast

2013 Test Period

	2013 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	40,150	55.52%	5.99%	3.32%	3.32%
Common Stock Equity	31,540	43.61%	9.21%	4.01%	5.74%
No Cost Capital	632	0.87%	0.00%	0.00%	0.00%
	72,322	100.00%		7.34%	9.06%
Net Rate Base (excl WIP)	72,329				
Depreciation	5,126				
Interest Coverage Ratio					2.73
FFO/Debt				20%	
FFO Interest Coverage				4.34	
Debt/Capital				56%	

2014 Test Period

	2014 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	47,950	55.58%	5.84%	3.25%	3.25%
Common Stock Equity	37,670	43.66%	9.21%	4.02%	5.75%
No Cost Capital	651	0.75%	0.00%	0.00%	0.00%
	86,271	100.00%		7.27%	8.99%
Net Rate Base (excl WIP)	86,063				
Depreciation	5,952				
Interest Coverage Ratio					2.77
FFO/Debt				20%	
FFO Interest Coverage				4.36	
Debt/Capital				56%	

The Yukon Electrical Company Limited
Credit Metrics 2013-2015 Forecast

2015 Test Period

	2015 Test Period				
	Mid Yr Balance	Ratio	Cost %	After Tax	Before Tax
Long-Term Debt	54,550	55.62%	5.77%	3.21%	3.21%
Common Stock Equity	42,860	43.70%	9.21%	4.03%	5.75%
No Cost Capital	670	0.68%	0.00%	0.00%	0.00%
	98,080	100.00%		7.23%	8.96%
Net Rate Base (excl WIP)	96,812				
Depreciation	6,820				
Interest Coverage Ratio					2.79
FFO/Debt				20%	
FFO Interest Coverage				4.39	
Debt/Capital				56%	

WL-YECL-18

Reference: Long Term Debt, Section 8, Page 8-7

During the 2013-15 test period, YECL is forecasting that it will issue long term debt all 3 years. The recommended rates of 4.30%, 5.00% and 5.75% are based on the best information available at the time the forecast was prepared.

Request:

(a) Please confirm that debt issues for YECL as well as its parent ATCO Electric are raised by Canadian Utilities Limited.

(b) Please provide the bond yields for a benchmark 30 year CU Ltd. bond, by month, for the 12 months ended June 2013, the corresponding 30-year long Canada bond yields and the resulting yield spreads.

(c) Please provide updated forecasts of 10 year and 30 year long Canada bond yields for each of the years 2013, 2014 and 2015. Please rationalize any changes in the forecast long Canada bond yields from current levels.

Response:

(a) Not confirmed. Debt issues for Yukon Electrical as well as its parent, ATCO Electric, are raised by CU Inc. The forecast all-in rates included in Yukon Electrical's application are 4.35%, 5.05% and 5.80% for the years 2013, 2014 and 2015, respectively.

(b) The below data relates to the 4.543% 30 year debenture issued by CU Inc. on October 24, 2011. This debenture was issued at an actual credit spread of 160 basis points. Included in the table, by month from June 2012 to June 2013, is the indicative debenture yield, the 30 year Long Canada bond yield, and the indicative credit spread of the debentures (calculated as the indicative debenture yield less the Long Canada yield).

	30-year Long Canada	CU Inc. 4.543% bond due Oct 2041	
Date	Yield (%)	Yield (%)	Spread (bps)
29-Jun-12	2.33	3.90	157
31-Jul-12	2.27	3.78	151
31-Aug-12	2.34	3.81	147
28-Sep-12	2.32	3.71	139
31-Oct-12	2.38	3.85	147
30-Nov-12	2.30	3.77	147
31-Dec-12	2.37	3.80	143
31-Jan-13	2.57	3.97	140
28-Feb-13	2.52	3.93	141
28-Mar-13	2.50	3.90	140
30-Apr-13	2.37	3.81	144
31-May-13	2.63	3.95	132
28-Jun-13	2.90	4.36	146

(c) Updated forecast long term debt rates are as follows:

	2013	2014	2015
LONG CANADA BOND RATE	3.00% - 3.20%	3.20% - 3.90%	4.00% - 4.40%
CREDIT SPREAD	1.45% – 1.65%	1.45% – 1.65%	1.45% – 1.65%
DEBENTURE RATE RANGE	4.45% – 4.85%	4.65% – 5.55%	5.45% - 6.05%
DEBENTURE RATE	4.65%	5.10%	5.75%
ISSUE COSTS	0.05%	0.05%	0.05%
RECOMMENDED ALL-IN RATE	4.70%	5.15%	5.80%

The forecast all-in rates for 2013 and 2014 have increased due to the significant increase in the underlying Long Canada Bond Rate observed over the past several weeks.

Please refer to WL-YECL-18(c) Attachments 1 through 4 for supporting forecast data from BMO Capital Markets, TD Economics, RBC Economics and Consensus Forecasts.

Interest Rate Forecasts
Percent (averages)

	Actual Jun	2013 Jul	Aug	Sep	2013 Q4	2014 Q1	Q2	Q3	Q4
Cdn. Yield Curve									
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50
3 month	1.02	1.03	1.03	1.03	1.03	1.03	1.03	1.28	1.53
6 month	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.30	1.55
1 year	1.11	1.12	1.15	1.18	1.25	1.36	1.50	1.75	2.05
2 year	1.15	1.19	1.26	1.32	1.45	1.65	1.95	2.25	2.50
3 year	1.26	1.30	1.39	1.46	1.60	1.85	2.15	2.45	2.70
5 year	1.63	1.75	1.85	1.90	2.00	2.20	2.45	2.75	3.00
7 year	1.95	2.10	2.15	2.20	2.35	2.55	2.80	3.05	3.25
10 year	2.24	2.40	2.50	2.55	2.70	2.90	3.10	3.30	3.55
30 year	2.76	2.85	2.95	3.00	3.10	3.30	3.50	3.70	3.90
1m BA	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.38	1.61
3m BA	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.42	1.66
6m BA	1.34	1.40	1.40	1.40	1.40	1.40	1.40	1.65	1.90
12m BA	1.45	1.50	1.55	1.55	1.65	1.75	1.90	2.15	2.40
Prime Rate	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.25	3.50
U.S. Yield Curve									
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
3 month	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
6 month	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
1 year	0.14	0.14	0.14	0.14	0.14	0.14	0.19	0.31	0.46
2 year	0.33	0.36	0.36	0.36	0.36	0.36	0.46	0.70	1.00
3 year	0.58	0.67	0.68	0.69	0.71	0.72	0.85	1.05	1.40
5 year	1.20	1.42	1.45	1.48	1.55	1.55	1.60	1.80	2.05
7 year	1.71	1.97	2.02	2.07	2.16	2.17	2.20	2.40	2.60
10 year	2.30	2.50	2.60	2.65	2.80	2.95	3.10	3.30	3.45
30 year	3.40	3.49	3.56	3.60	3.75	3.90	4.05	4.15	4.30
1m LIBOR	0.19	0.20	0.20	0.20	0.20	0.20	0.25	0.25	0.25
3m LIBOR	0.27	0.25	0.30	0.30	0.30	0.35	0.35	0.40	0.40
6m LIBOR	0.41	0.40	0.40	0.45	0.45	0.50	0.50	0.55	0.55
12m LIBOR	0.68	0.70	0.70	0.70	0.75	0.75	0.85	1.00	1.15
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Other G7 Yields									
ECB Refi	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
10yr Bund	1.60	1.65	1.75	1.85	2.00	2.25	2.50	2.70	2.95
BoE Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
10yr Gilt	2.31	2.35	2.45	2.50	2.65	2.90	3.05	3.25	3.45
BoJ O/N	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
10yr JGB	0.85	0.85	0.85	0.85	0.90	0.95	1.05	1.15	1.20

INTEREST RATE OUTLOOK

	Spot Rate	2012				2013				2014			
	Jul-11	Q1	Q2	Q3	Q4	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA													
Overnight Target Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.50
3-mth T-Bill Rate	1.02	0.91	0.87	0.97	0.92	0.98	1.02	0.95	0.95	0.95	0.95	1.05	1.40
2-yr Govt. Bond Yield	1.13	1.20	1.03	1.07	1.14	1.00	1.22	1.20	1.25	1.30	1.35	1.55	1.70
5-yr Govt. Bond Yield	1.76	1.57	1.25	1.30	1.38	1.30	1.80	1.75	1.90	2.00	2.10	2.20	2.35
10-yr Govt. Bond Yield	2.45	2.11	1.74	1.73	1.80	1.76	2.44	2.45	2.55	2.70	2.75	2.80	2.85
30-yr Govt. Bond Yield	2.93	2.66	2.33	2.32	2.36	2.50	2.89	2.95	3.05	3.10	3.15	3.20	3.25
10-yr-2-yr Govt Spread	1.33	0.91	0.71	0.66	0.66	0.76	1.22	1.25	1.30	1.40	1.40	1.25	1.15
U.S.													
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
3-mth T-Bill Rate	0.04	0.07	0.09	0.10	0.05	0.07	0.04	0.10	0.20	0.20	0.20	0.20	0.20
2-yr Govt. Bond Yield	0.34	0.33	0.33	0.23	0.25	0.25	0.36	0.30	0.40	0.45	0.55	0.75	0.90
5-yr Govt. Bond Yield	1.41	1.04	0.72	0.62	0.72	0.77	1.41	1.25	1.40	1.50	1.60	1.75	1.90
10-yr Govt. Bond Yield	2.59	2.23	1.67	1.65	1.78	1.87	2.52	2.45	2.60	2.75	2.85	2.95	3.05
30-yr Govt. Bond Yield	3.63	3.35	2.76	2.82	2.95	3.10	3.52	3.65	3.75	3.90	4.00	4.00	4.05
10-yr-2-yr Govt Spread	2.25	1.90	1.34	1.42	1.53	1.62	2.16	2.15	2.20	2.30	2.30	2.20	2.15
CANADA - U.S SPREADS													
Can - U.S. T-Bill Spread	0.99	0.84	0.78	0.87	0.87	0.91	0.98	0.85	0.75	0.75	0.75	0.85	1.20
Can - U.S. 10-Year Bond Spread	-0.13	-0.12	0.07	0.08	0.02	-0.11	-0.08	0.00	-0.05	-0.05	-0.10	-0.15	-0.20

F: Forecast by TD Bank Group as at July 2013; All forecasts are end-of-period; Source: Bloomberg, Bank of Canada, Federal Reserve.

GLOBAL STOCK MARKETS

	Jul-11	30-Day % Chg.	YTD % Chg.	52-Week High	52-Week Low
S&P 500	1,653	1.6	15.9	1,669	1,335
S&P/TSX Composite	12,307	0.7	-1.0	12,879	11,425
DAX	8,150	-0.9	7.1	8,531	6,390
FTSE 100	6,537	3.1	10.8	6,840	5,498
Nikkei	14,473	8.7	39.2	15,627	8,366
MSCI AC World Index*	364	0.1	7.0	380	303

* Is a weighted equity index including both developed and emerging markets
Source: Bloomberg.

COMMODITY PRICE FORECASTS

	Price	52-Week	52-Week	2012				2013F				2014F				Annual Average		
	Jul-11	High	Low	Q1	Q2	Q3	Q4	Q1	Q2	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	2012	2013F	2014F
Crude Oil (WTI, $US/bbl)	107	107	84	103	93	92	88	94	94	93	95	95	92	95	95	94	94	94
Natural Gas ($US/MMBtu)	3.69	4.38	2.63	2.45	2.28	2.88	3.40	3.50	4.01	3.85	4.05	3.90	4.00	3.90	4.25	2.75	3.85	4.01
Gold ($US/troy oz.)	1286	1790	1201	1690	1612	1655	1717	1632	1418	1275	1200	1175	1150	1175	1250	1668	1381	1188
Silver (US$/troy oz.)	20.1	35.0	18.5	32.6	29.5	30.0	32.6	30.1	23.3	19.6	17.9	17.8	17.0	18.0	19.3	31.17	22.71	18.00
Copper (cents/lb)	309	379	301	376	357	350	359	360	325	318	335	330	325	320	310	361	335	321
Nickel (US$/lb)	6.19	8.50	6.04	8.91	7.77	7.42	7.70	7.85	6.80	7.50	8.00	8.00	8.60	8.50	8.20	7.95	7.54	8.33
Aluminum (Cents/lb)	82	100	80	99	90	87	91	91	83	90	96	96	96	100	100	92	90	98
Wheat ($US/bu)	8.86	10.89	8.77	9.54	9.36	9.90	10.05	9.32	9.14	9.25	9.30	9.35	9.25	9.00	8.75	9.71	9.25	9.09

F: Forecast by TD Bank Group as at July 2013; All forecasts are period averages; Source: Bloomberg, USDA (Haver).

Interest rate outlook

%, end of period

	Actuals						Forecast					
	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4
Canada												
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50
Three-month	0.92	0.88	0.90	1.05	0.98	1.02	1.00	1.00	1.05	1.10	1.25	1.55
Two-year	1.20	1.03	1.15	1.05	1.00	1.22	1.15	1.20	1.30	1.55	1.80	2.00
Five-year	1.56	1.25	1.35	1.30	1.30	1.80	1.85	1.95	2.10	2.25	2.45	2.55
10-year	2.11	1.74	1.75	1.75	1.88	2.44	2.50	2.70	2.90	3.15	3.30	3.40
30-year	2.64	2.33	2.40	2.40	2.50	2.90	3.00	3.20	3.40	3.55	3.65	3.75
United States												
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Three-month	0.07	0.09	0.10	0.09	0.07	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Two-year	0.34	0.25	0.25	0.25	0.25	0.36	0.35	0.55	0.65	0.85	1.20	1.60
Five-year	1.04	0.70	0.72	0.70	0.77	1.41	1.45	1.75	1.90	2.10	2.30	2.50
10-year	2.20	1.60	1.65	1.70	1.87	2.52	2.60	2.85	3.05	3.30	3.45	3.60
30-year	3.32	2.70	2.80	2.90	3.10	3.52	3.70	3.90	4.10	4.20	4.30	4.35
United Kingdom												
Bank rate	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Two-year	0.43	0.40	0.20	0.20	0.21	0.41	0.30	0.40	0.50	0.60	0.70	0.70
10-year	2.00	1.80	1.70	1.70	1.78	2.46	2.50	2.65	2.75	2.85	2.90	3.00
Eurozone												
Refi rate	1.00	1.00	0.75	0.75	0.75	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Two-year	0.09	0.10	0.00	0.00	-0.02	0.20	0.15	0.20	0.30	0.30	0.35	0.40
10-year	1.61	1.50	1.50	1.50	1.29	1.73	1.70	1.85	2.00	2.10	2.15	2.25
Australia												
Cash target rate	4.25	3.50	3.50	3.00	3.00	2.75	2.50	2.25	2.25	2.25	2.25	2.25
Two-year	3.49	2.46	2.49	2.75	2.83	2.58	2.40	2.40	2.50	2.50	2.60	2.70
10-year	4.10	3.04	2.94	3.00	3.42	3.76	3.70	3.75	3.95	4.10	4.35	4.50
New Zealand												
Cash target rate	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.75	3.00	3.00	3.25
Two-year swap	3.11	2.37	2.55	2.60	2.85	2.85	3.10	3.20	3.30	3.40	3.40	3.50
10-year swap	4.17	3.40	3.57	3.80	3.96	4.16	4.50	4.60	4.60	4.60	4.90	5.30
Yield curve												
Canada	91	71	60	70	88	122	135	150	160	160	150	140
United States	186	135	140	145	162	216	225	230	240	245	225	200
United Kingdom	157	140	150	150	157	205	220	225	225	225	220	230
Eurozone	152	140	150	150	131	153	155	165	170	180	180	185
Australia	61	58	45	25	59	118	130	135	145	160	175	180
New Zealand	106	103	102	120	111	131	140	140	130	120	150	180

* Two-year/10-year spread in basis points

Source: Reuters, RBC Economics Research

Central bank policy rate

%, end of period

		Current	Last	
United States	Fed funds	0.0-0.25	1.00	Dec. 16, 2008
Canada	Overnight rate	1.00	0.75	Sep. 8, 2010
United Kingdom	Bank rate	0.50	1.00	Mar. 5, 2009

		Current	Last	
Eurozone	Refi rate	0.50	0.75	May 2, 2013
Australia	Cash rate	2.75	3.00	May 8, 2013
New Zealand	Cash rate	2.50	3.00	Mar. 10, 2011

Source: Bloomberg, Reuters, RBC Economics Research

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date			
						1.0%		2.5%	
Unemployment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligations d'État de 10 ans %*	
2013	2014	2013	2014	FY 13-14	FY 14-15	End Oct'13	End Jul'14	End Oct'13	End Jul'14
7.1	6.9	-49.0	-42.0	na	na	na	na	na	na
7.0	6.7	-48.2	-39.6	na	na	1.0	1.2	2.6	3.2
7.1	6.9	-50.1	-33.0	-17.0	-6.0	1.0	1.1	2.4	2.5
7.1	7.0	-52.4	-42.4	na	na	1.0	1.0	na	na
7.1	7.0	-54.0	-50.0	-11.0	-5.0	1.0	1.2	1.9	2.2
7.0	6.7	-57.0	-48.0	-18.0	-11.0	1.0	1.0	2.6	3.0
7.1	7.1	-65.7	-62.5	na	na	na	na	na	na
7.1	7.0	-55.5	-46.0	na	na	1.0	1.0	2.5	2.8
7.1	6.8	-54.5	-53.1	na	na	1.0	1.0	2.5	2.7
7.0	6.8	-54.0	-45.3	-18.0	-8.0	1.0	1.0	2.3	2.9
7.0	6.7	-55.5	-50.5	-19.0	-10.0	1.0	1.3	2.6	3.2
7.1	7.1	-54.7	-46.0	na	na	1.0	1.1	2.5	2.8
na	na	na	na	na	na	na	na	na	na
7.3	8.0	na	na	na	na	1.0	1.0	2.2	2.8
7.1	7.0	-54.2	-46.5	-16.6	-8.0	1.0	1.1	2.4	2.8
7.1	6.9	-53.6	-46.2	-16.1	-9.1				
7.1	7.0	-59.1	-52.1	-16.8	-9.1				
7.3	8.0	-48.2	-33.0	-11.0	-5.0	1.0	1.3	2.6	3.2
7.0	6.7	-65.7	-62.5	-19.0	-11.0	1.0	1.0	1.9	2.2
0.1	0.3	4.5	7.4	3.2	2.5	0.0	0.1	0.2	0.3
7.1	6.9								

International Trade – and Domestic – Headwinds?

Output-based GDP rose by 0.1% (m-o-m) in April after Q1's 0.6% (q-o-q) surge. In y-o-y terms, growth slowed from the 1.7% pace seen in February and March to 1.4% in April. Services led the monthly uptick in GDP, accelerating by 0.3% following a 0.2% rise in March, with wholesale, retail and financial & insurance activity recording gains. By contrast, goods-producing industries had a weak month. Industrial production fell by 0.4% (m-o-m) following a 0.5% rise in March, dragged down by a 1.5% contraction in mining, quarrying, oil & gas extraction over the month. Manufacturing did manage a 0.2% rise following a flat month in March, supported by durables output, but the industrial sector has been impacted by weakness in Canada's major export markets (and more recently by signs of waning domestic demand). US manufacturing has been in the doldrums, although a few leading indicators suggest it could be on the cusp of rebounding (see page 5). This will hopefully give some impetus to Canadian industry which saw manufacturing sales tumbled from a 0.6% (m-o-m) decline in April to -2.4% in May. The 2013 production consensus has faltered this month.

May's trade deficit narrowed to C$-303mn from C$-951mn in April as a 3.2% (m-o-m) fall in imports outpaced the 1.6% drop in exports. A softer job market (June payrolls were mostly unchanged after May's 95,000 surge) is also weighing on domestic demand. On the upside, after a sluggish year, June housing starts recorded a stronger-than-expected 199,586 gain while May's figure was revised from 200,178 to 204,616. Softer housing activity going into 2014 is still expected, and the prospect of a more serious retrenchment could also occur, although the 2013 housing starts outlook has been upgraded.

Canada Overnight Lending Rate – July 8, 2013 = 1.00%

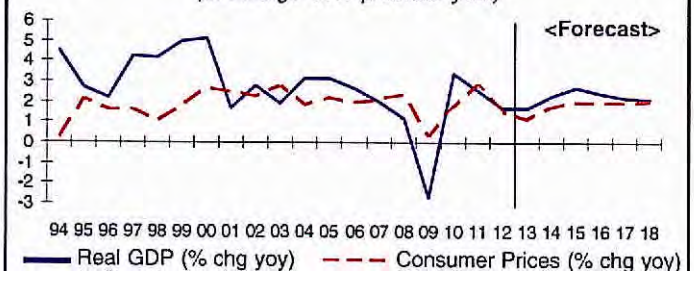
FORECASTS	End Sep. 2013	End Dec. 2013	End Mar. 2014	End June 2014
Consensus Mean Average:	1.00%	1.00%	1.02%	1.03%
Mode (most frequent forecast):	1.00%	1.00%	1.00%	1.00%

Direction of Trade – 2012

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	74.5	United States	50.6
China	4.3	China	11.0
United Kingdom	4.1	Mexico	5.5
EU	*8.5*	*Asia (ex. Japan)*	*14.0*
Asia (ex. Japan)	*6.0*	*EU*	*10.9*
Latin America	*3.0*	*Latin America*	*9.0*

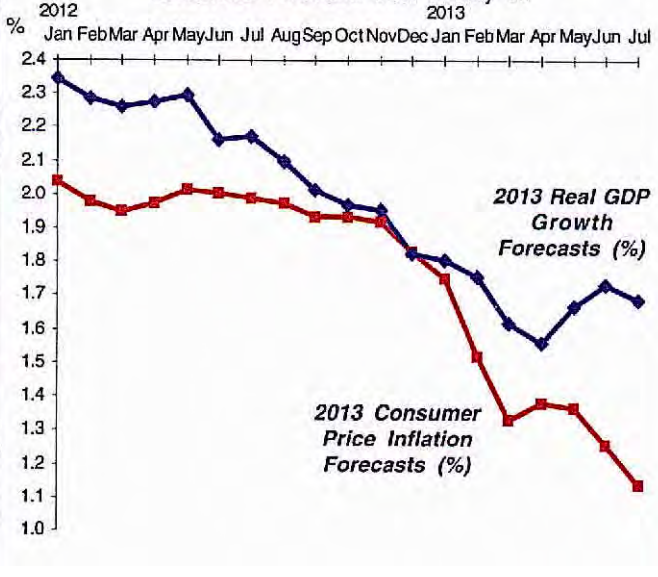
Real Growth and Inflation

(% change over previous year)



2013 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



WL-YECL-19

Reference: RFID, Section 8, Page 8-8

Page 8-8 states that the RFID balance at the end of 2012 was $73,000. Schedule 8-4 shows an RFID balance at the end of 2012 of $69,000.

Request:

What is the correct RFID end of year balance for 2012?

Response:

The correct RFID end of year balance for 2012 is $69,000 as shown on Schedule 8-4.

WL-YECL-20

Reference: Allowance for Working Capital, Section 8, Schedule 8.10

Schedule 8.10. Line 12 shows large fluctuations in income taxes receivable (payable).

Request:

Please explain, on a year-to-year basis from 2008 to 2015, the large fluctuations in income taxes receivable (payable).

Response:

The fluctuations for 2008-2012 are a function of the amount of tax installments made as compared to the tax provision for the year. If the actual tax provision is higher or lower than the installments, there will be an income tax payable or receivable at year end.

For forecast test period, the balances in income taxes receivable/payable are based on the forecast income tax expense, tax installments, and tax refunds or payments relating to the prior year associated with installments being too high or too low. In reviewing the figures, Yukon Electrical noted that it inadvertently reversed the sign for 2014 Income Taxes receivable (payable). The receivable balance of $704 should have been a payable. Yukon Electrical will correct for this error as part of its compliance filing once the final revenue requirement is known.

WL-YECL-21

Reference: Capital Additions, Section 9

YECL wishes to have more information on capital additions

Request:

(a) YECL states that generation assets are continually monitored through power plant inspections and monitoring and provides a list of broad reasons that can dictate the need for new generation assets to be put in place. Please provide copies of the inspection and monitoring reports, linked to the list of reasons, which are resulting in generation capital additions during the test years.

(b) YECL states that it forecasts new extensions are based on discussions with communities, developers, engineering firms and customers. Please provide additional details on these discussions.

(c) System Performance Projects – Please provide the complete list of items that are monitored for system performance. What levels, and why, are considered acceptable for each item.

(d) Please describe the process that is used in deciding to refurbish or overhaul equipment instead of replacing it.

(e) Please provide a list of expected life cycles of priority/major equipment.

(f) Please provide a copy of the life cycle planning report(s) that are contributing to capital additions in the test years.

(g) Please provide a list of forced projects for the years 2008 to 2012 and the basis for forecasts in the test years.

(h) If different than the reports requested in a) above, please provide copies of the distribution system performance reports that are prepared for capital forecasting for the years 2008 to the present.

(i) If not included in the reports already requested, please provide a complete list of the Type A and Type B priorities. Please link capital projects from 2008 to 2015 to these priorities.

(j) Please provide a list, on a year-to-year basis, from 2008 to 2012 of all unplanned outages. Please explain what performance criteria are calculated and tracked by YECL (SAIDI, CAIDI, etc.) and present the criteria for each year.

(k) For all capital projects completed in the period from 2008 to present, please present a schedule and evaluation of YECL's ability to forecast, and maintain, project budgets. Included in this, please include initial project budgets and actual costs. Please provide an evaluation, on a per project basis, of the reasons for any actual project cost being greater than 110% of the initial budget.

Response:

(a) Please refer to the following attachments for typical examples of inspection reports, repair reports and in-field reporting for units:

- WL-YECL-21(a) Attachment 1 – Caterpillar Service Report
- WL-YECL-21(a) Attachment 2 – Watson Lake Load Chart
- WL-YECL-21(a) Attachment 3 – O.E.M. Failure Analysis Report
- WL-YECL-21(a) Attachment 4 – Unit Inspection Findings Report
- WL-YECL-21(a) Attachment 5 – Unit Maintenance History

The specific need for each new generation asset is included as part of the Business Case for each unit.

(b) Please refer to the response to information request CW-YECL-1.

(c) Yukon Electrical reviews any unplanned outages that are identified to have a system coordination issue. Yukon Electrical completes regular substation and system checks to ensure voltage, current and loading are all acceptable. Any anomalies are investigated and corrective actions are completed on a timeline consistent with the deficiency. System performance projects also include inadequate clearance issues.

(d) Yukon Electrical will complete maintenance and overhauls on recommended intervals. When the units have reached replacement operating ranges as noted in WL-YECL-21(e), an inspection of unit condition will be completed and a business case is developed to replace the unit.

(e) Generation planning criteria for 1200 RPM units recommends replacement after 90,000 to 126,000 hours based on condition assessments in this operating range. Generation planning criteria for 1800 RPM units recommends replacement after 60,000 to 88,000 hours based on condition assessments in this operating range. Substation transformers typically have a 30 plus year life cycle which can be adjusted according to results of regular transformer oil and gas tests which will identify insulation breakdown and internal issues. Poles and street lights typically have a 30 plus year life depending on a variety of factors including external stresses (insects, vandalism, interference) and degradation of metal of street lights.

(f) Yukon Electrical does not prepare life cycle planning reports. The need for Yukon Electrical's forecast capital additions is detailed in the business cases filed with its Application.

(g) Please refer to WL-YECL-21(g) Attachment 1. Forced projects for the test years are forecasted based on expected upcoming new development projects and upgrades to the current system based on other projects in the area.

(h) Yukon Electrical reviews distribution system performance, outage reports and results of distribution system inspections when preparing the capital forecast. Please refer to UCG-YECL-40(a) Attachment 1 for system performance reports from 2008 – 2012. Please refer to WL-YECL-21(h) Attachment 1 for a copy of a typical Maintenance Work Request produced by field staff during distribution system inspections.

(i) Please refer to WL-YECL-21(i) Attachment 1.

(j) Please refer to WL-YECL-21(j) Attachment 1, tab **WL-YECL-21(j) - Part 1**, for a list of outages from 2008 to 2012.

Yukon Electrical tracks the following reliability indices as defined below:

SAIFI refers to the System Average Interruption Frequency Index. This index is defined as the average number of interruptions per customer served per

year. SAIFI is calculated by taking the total number of customers affected by interruptions divided by the total number of customers served.

SAIDI refers to the System Average Interruption Duration Index. This index is defined as the system average interruption duration for customers served per year. SAIDI is calculated by taking the total customer hours of interruptions divided by total customers served.

CAIDI refers to the Customer Average Interruption Duration Index. This index is defined as the customer average interruption duration for customers interrupted during the year. CAIDI is calculated by taking the total customer hours of interruptions divided by total customer interruptions.

IOR refers to the Index of Reliability which defines the annual customer-hours that service is available measured as a percentage.

SAIFI, SAIDI, CAIDI, and Index of Reliability are reported on annually.

Please refer to WL-YECL-21(j) Attachment 1, tab **WL-YECL-21(j) - Part 2** for performance criteria for 2008-2012.

(k) Please refer to WL-YECL-21(k) Attachment 1. This schedule compares the 2008-2009 GRA forecasts to the 2008 and 2009 actual figures and provides variances explanations for any actual project cost being greater than 110% of the initial budget. The remaining actual periods were not compared to forecast since this period is outside of the previous test years.

Service Report

Report Header Information					
Work Order	0806234	Dealer Code	N065	Manufacturer	Caterpillar Inc.
Employee ID	2861	Service Date	12/9/2010	Model	3512
Customer	Yukon Electrical	Customer Equipment Number	Unit 2	Serial Number	67Z00491
SMU	28374 Hours	Equipment Location	YECL Watson Lake		
IN Date		Promise Date		OUT Date	
Instructions	Perform a valve and injector set and repair cyl 12 for running cold. New injector installed in July 2010.				

Truck Information			
Truck Make		Truck Model	
VIN		Cab Type	
Vehicle Config		Delivery Date	

Segment Info			
Segment No: 02			
Segment Description: Perform Valve and Injector Set			
Job Code		Description	
Component Code		Description	
Start Date	12/15/2010	End Date	12/15/2010
Instructions			

SIMS / Part Causing Failure										
Segment No	Part Number	Part Name	Qty	SMCS	Primary	Secondary	Group Number Containing Part	Group Name	Product Inoperable?	CAT Item

Labor									
Segment No	Operation No	Employee ID	Date	Overtime Indicator	Labor Codes	Start Time	End Time	Shift	Man Hours
02		2861	12/9/2010	Regular	mef	12:00 AM	12:00 AM	1	4
02		2861	12/9/2010	Overtime	mef	12:00 AM	12:00 AM	1	2
02		2861	12/10/2010	Regular	mef	12:00 AM	12:00 AM	1	3

Labor									
Segment No	Operation No	Employee ID	Date	Overtime Indicator	Labor Codes	Start Time	End Time	Shift	Man Hours
02		2861	12/12/2010	Overtime	mef	12:00 AM	12:00 AM	1	0.5

Miscellaneous Costs							
Segment No	Operation No	Employee ID	Date	Charge Codes	Qty	Description	Cost

Mileage						
Segment No	Operation No	Employee ID	Vehicle	Date	Charge Codes	Distance

Repair Background

Segment No: 02	
Customer Complaint	Cylinder 12 runing cold
Cause of Failure	Adjustment and pyro connection
Resultant Damage	Unknown
Repair Process Comments	12/9/2010: 6 hrs MEF: Unit off and locked out. Valve covers off. Pin engine and perform valve and injector set. Int: 0.020", Exh: 0.040", Inj: 86.0 mm Injectors synchronized. All before readings recorded for records.Valve covers on and done for night. Found inj timing on 12 to be 86.7mm, (way out compared to others) 12/10/2010: 3 hrs MEF: Had unit started and ran online to check cylinder temps. !2 ad 10 are coldest, but notout of max allowable 50C diff from average. Shut unit down and turned sync screws for 12 and 10 two turns ccw to increase fuel. Started and ran online again. Cyl 10 emp increased but 12 not as much. Look into pyro for ccyl 12. Found a loose socket, squeaazed slightly and connects better now, Used the LH turbo pyro lead to compare temp and good now. Cyl 12 temp now inline with the average of the others. Wrote up the customer records for the 3516 and 3512 valve sets, wrote up time and sent in via email. Picked up tote of tools from greyhound. 12/12/2010: 0.5 hrs MEF: service report.

Customer Signature	Technician Signature

Workorder Closing	
Yes	Is the Job Completed?
No	Are unused parts being restocked?
No	Is a Reman core being returned?

No	Are warranty parts being returned?
No	Are checked-out tools being returned?
No	Has the information been entered to SIMS?

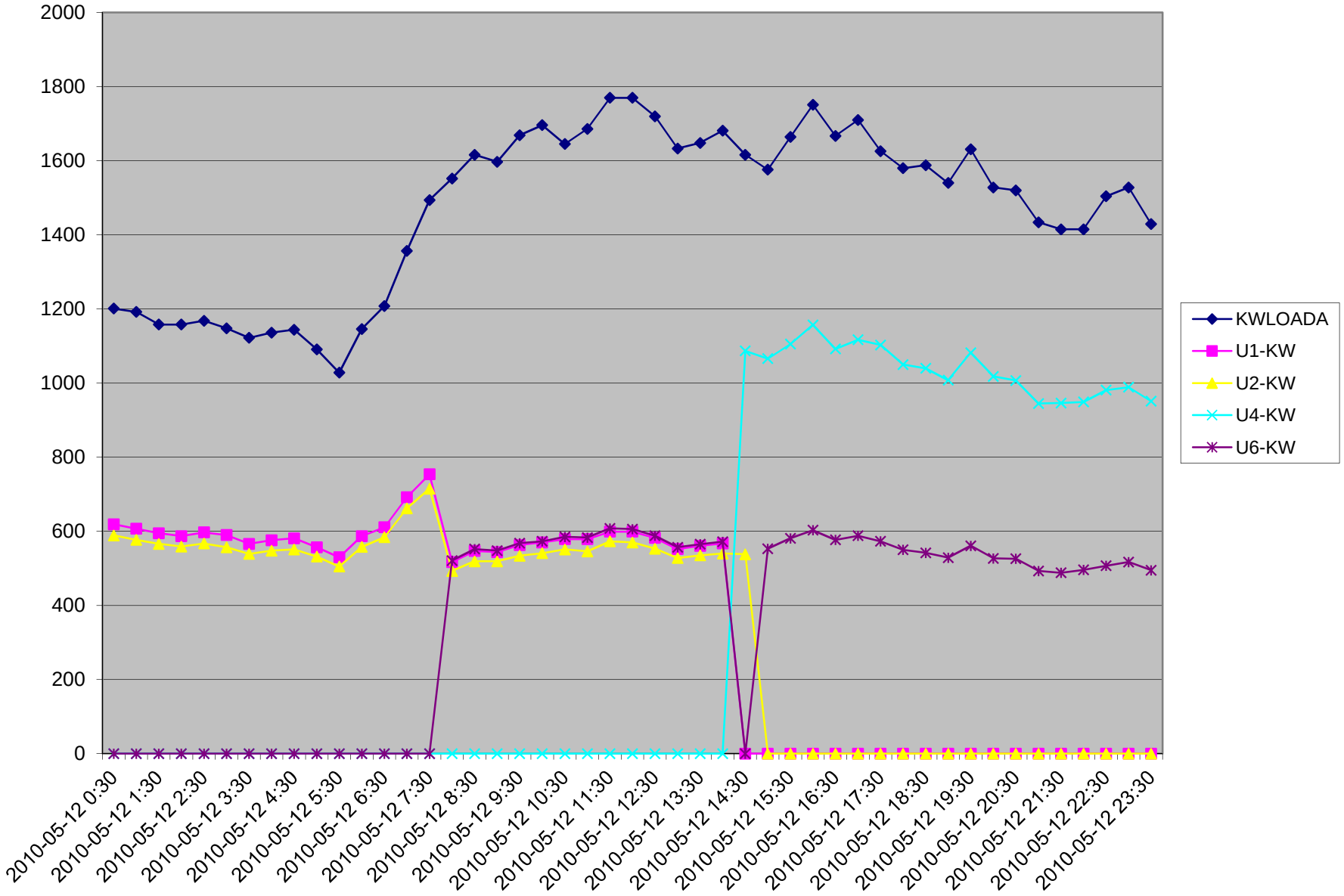
Additional Opportunities	
No	Is there Additional Service to be done?
No Answer	Did the customer request a quote for additional service?
No	Did the customer request a PSSR to contact them?
Comment	

Parts				
Segment No	Order ID	Work Order	Operation	Additional Notes

Application Data		
Application	Report	Created

File Attachments				
Name	Size	Modified	Title	Description

Digital Images


2000
1800
1600
1400
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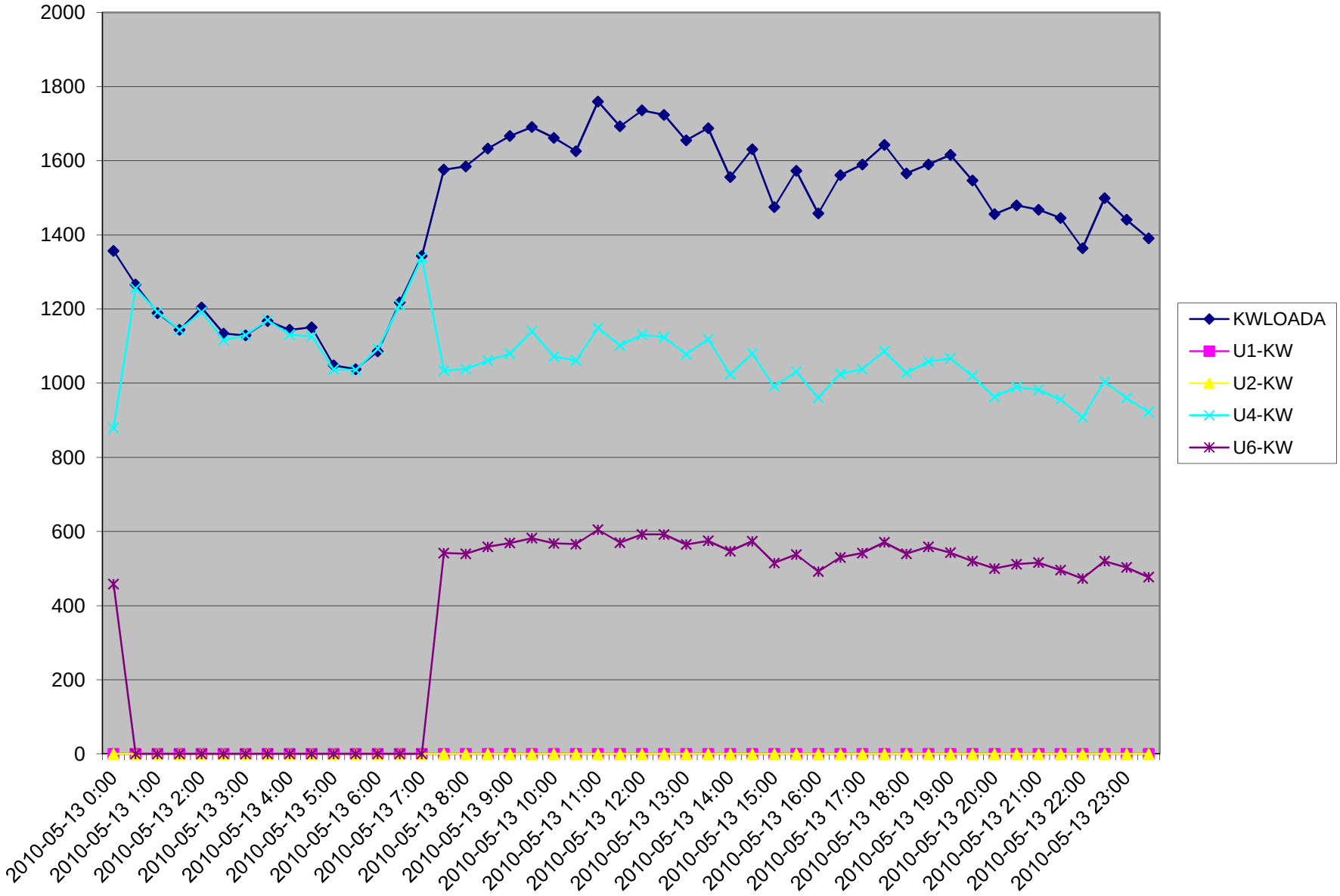
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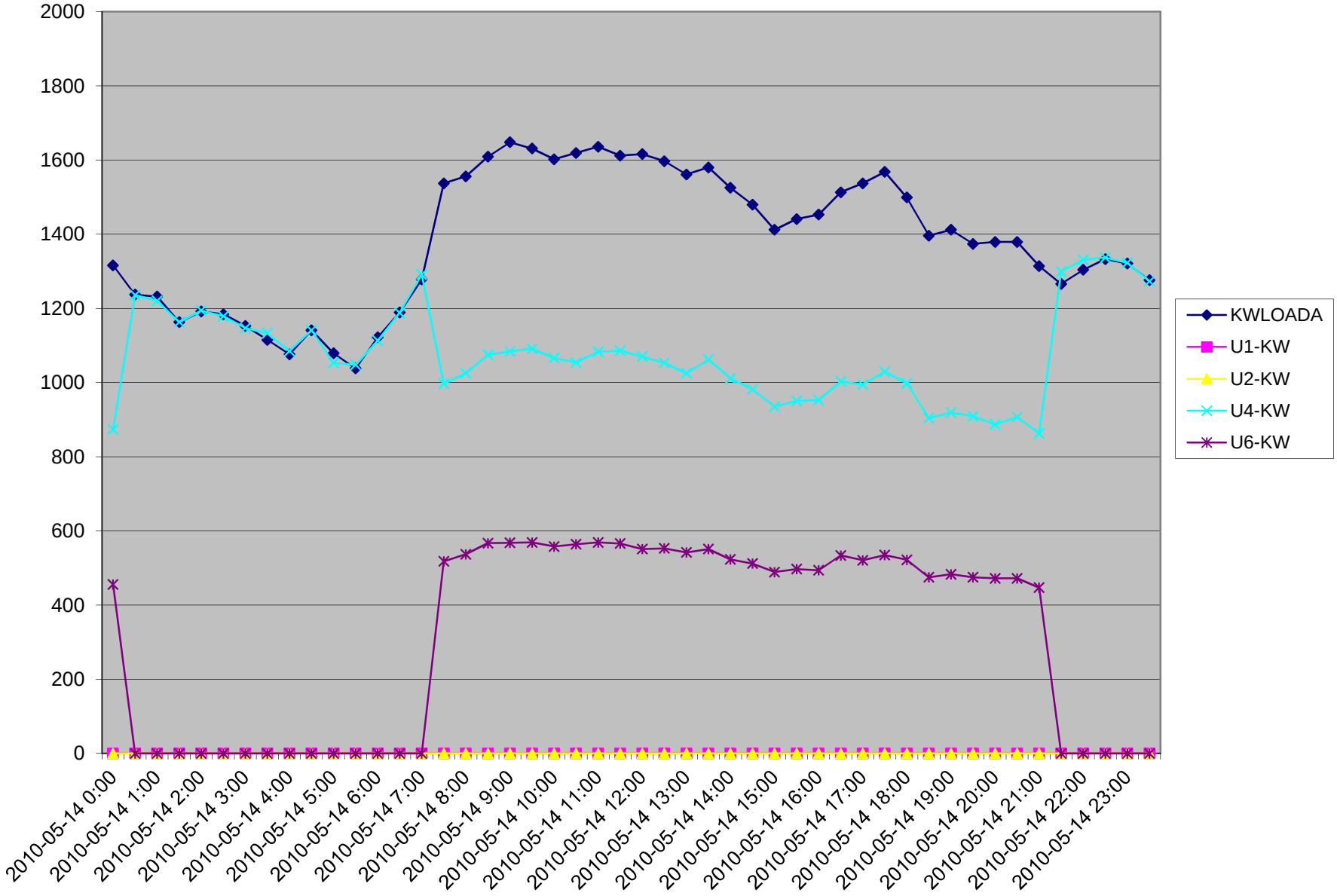
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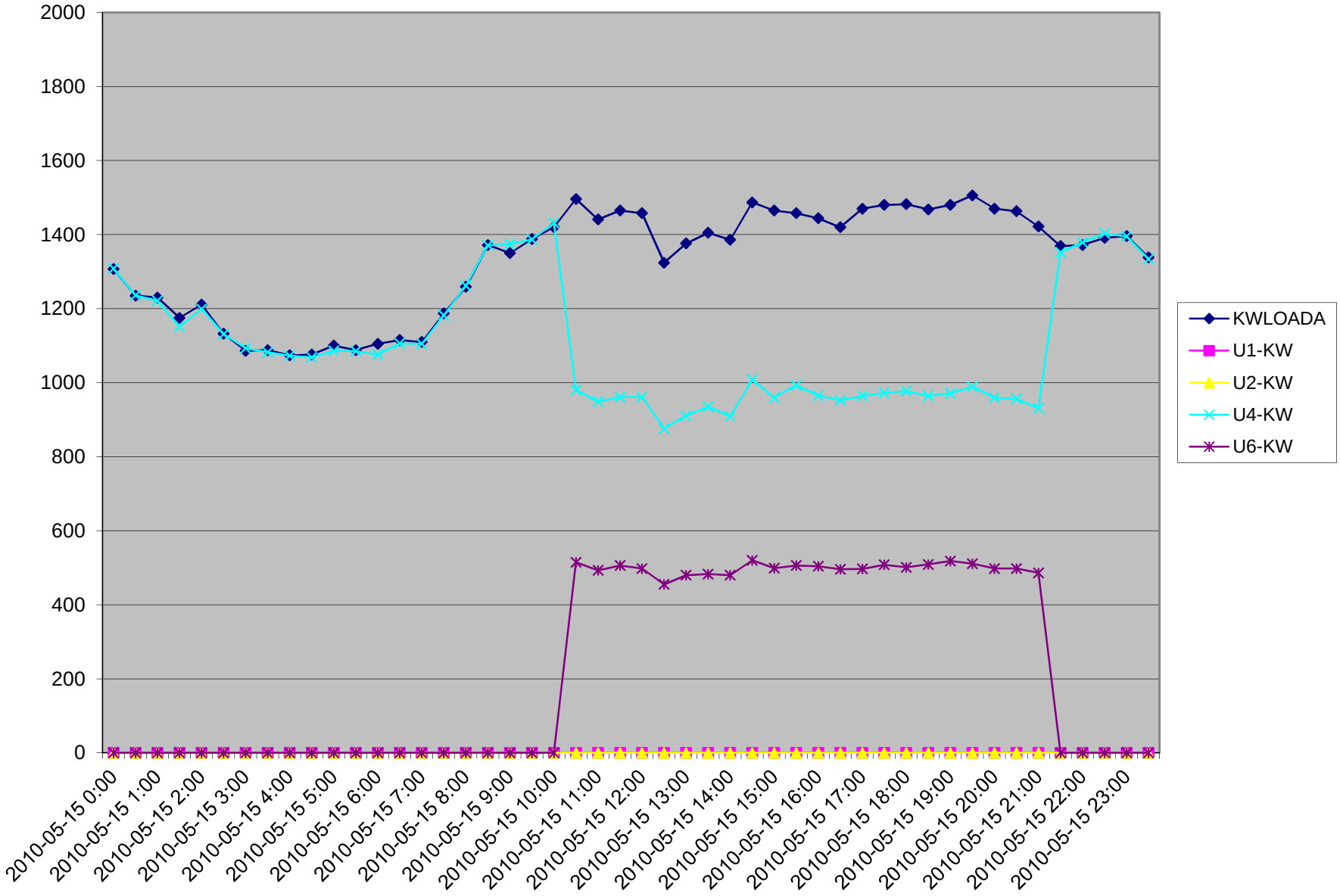
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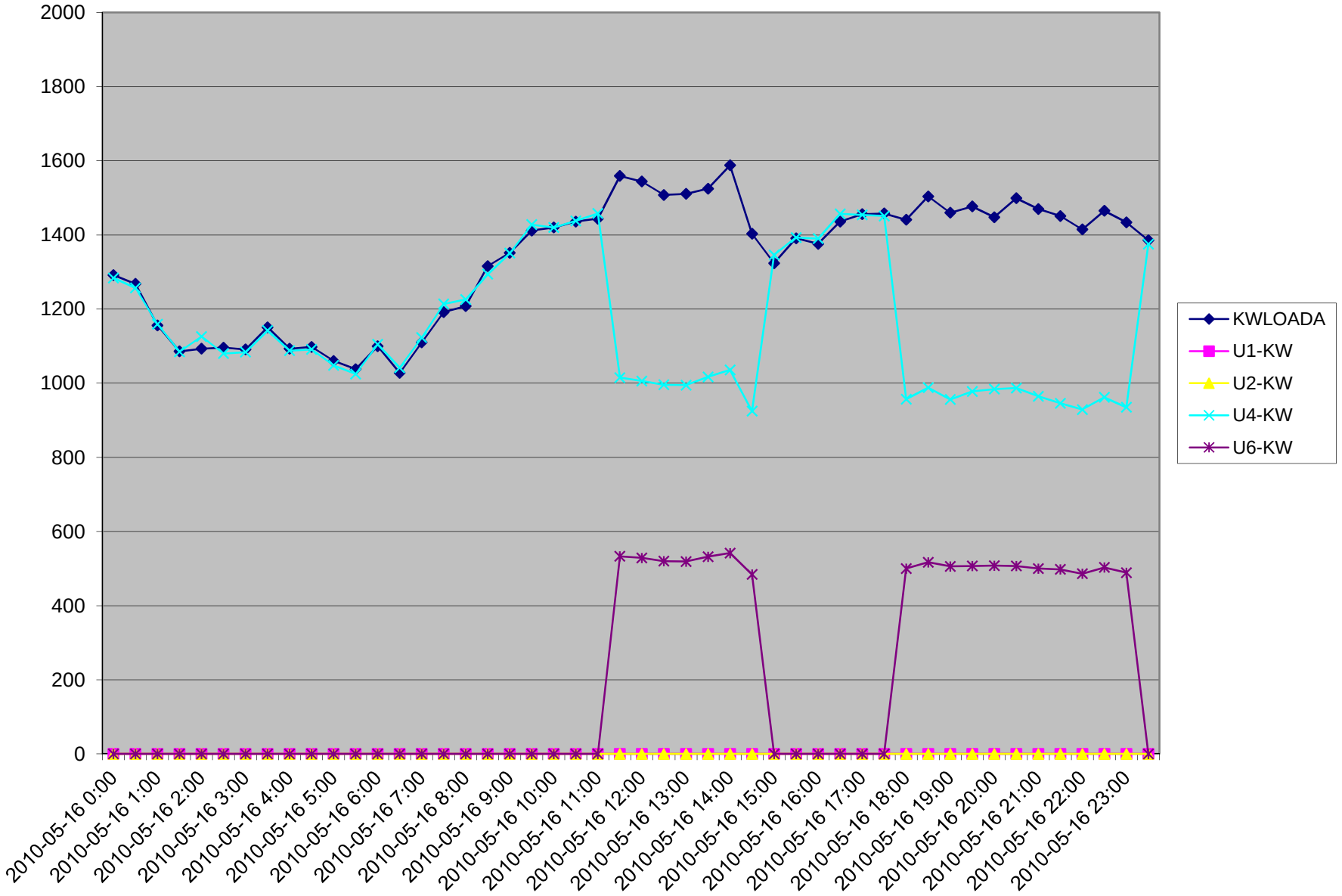
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OEM REMANUFACTURING

Report Type: Failure Analysis

Background Information:

Finning Work Order Number: **0805702**		*FT4900 Number:*	
Previous Work Order Number: **Not found**	*Source:* **Reman - Other**	*Customer:* **Finning Canada**	
OEM Work Order Number: **00089851**		*Final Customer:* **Yukon Electrical Company**	

Part / Component Information:

Part / Component Description: **3600 Turbocharger**		*Machine Model:*	*Manufacturer:*
Machine Serial Number: **8RB00292**	*Unit Number:*		*Machine Hours:* **134940**
Component Serial Number: **C25403-492736**	*Finished Good Number:* **7E9668XCH**	*Part / Component Hours:* **6549**	*Location:*
Original Sales Date: **3/30/2009**	*Installation Date:* **4/17/2009**		*Failure Date:* **3/1/2010**

Summary:

Customer Complaint (Cause for Removal):

Root Cause of Failure (Failure Description):

The Turbocharger had unusually high levels of soot deposits on the surfaces of the various Compressor End sub-components, as well as a heavy build-up of exhaust gas debris on the Turbine End sub-components. Heavy and uneven flaking of debris from the Turbine Wheel blades had caused the Rotating Assembly to operate in an unbalanced state, at time(s) during operation. While light Wheel rub had occurred, no sub-components were broken. There were no identifiable problems associated with this Turbocharger however; a number of external factors have been identified and it is likely that one, or more, had been factors in the failure of this Turbocharger.

Correction:
Return to Reman Standard

Complications:

Reliability Information:

Part Number Causing Failure: **Unknown**	*Description of Part Causing Failure:*
CPI Related to Failed Part:	*Reference Literature Related to Failed part:*

SIMS Entries Made:

Qty:	*Part #:*	*Group #:*	*Desc. Code:*	*Comments*	*Rendered Inoperable:*	*Cause of Failure:*

Authored by:

Name: **Robert Gibson**	*Title:* **Tech Lead**	*Date:* **3/23/2010**	*Rev. #:*

Reviewed & Approved by:

Name: **Robert Gibson**	*Title:* **Tech Manager-Undercarriage**	*Date:* **3/23/2010**

Final Approval by:

Name: **Robert Bierman**	*Title:* **Tech Director**	*Date:* **3/23/2010**

BACKGROUND

Machine Serial Number: 8RB00292

Component Serial Number: C25403-492736

At the time this Turbocharger had been removed from operation it had accumulated 6549 service hours.

While a previous OEM Work Order number was not located on this Turbocharger, there was one previous Work Order number (1237124 / 10) however; it is unclear which organization last re-manufactured this component.

The Customer had indicated, through a series of e-mails, that the recent Turbochargers on this Engine had experienced problems, resulting in a reduced service life. However; the exact nature and origin of the problem(s) was / were uncertain.

OBSERVATIONS

The Turbocharger had an Identification Plate (Figure 1) indicating this was a 7E9668 Turbocharger (Serial Number C25403-492736). The style of Rivets used to secure the Identification Tag to the Turbocharger Cartridge are typically used by the Original Equipment Manufacturer.

Figure 1 – Identification Plate

The various ports were securely covered, as noted in Figures 2 – 5.

Figure 2 - 7E9668 Turbocharger – View 1

Figure 3 - 7E9668 Turbocharger – View 2

Figure 4 - 7E9668 Turbocharger – View 3

Figure 5 - 7E9668 Turbocharger – View 4

The Turbocharger was equipped with a Block Assembly located on the Oil Inlet Port, as noted in Figures 6 – 8.

This type of Block Assembly is not normally shipped with the Turbocharger – the Inlet Oil Port is typically just covered with tape.

The Oil Outlet Port had no such Block Assembly.

Figure 6 – Block on the Oil Inlet – View 1

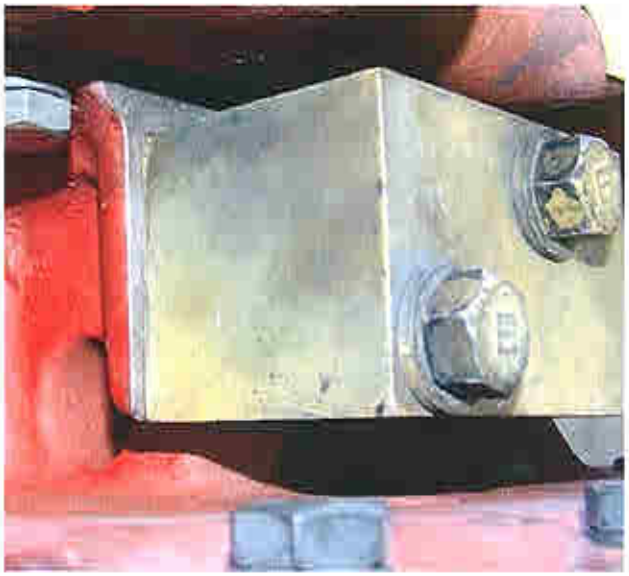

Figure 7 – Block on the Oil Inlet – View 2

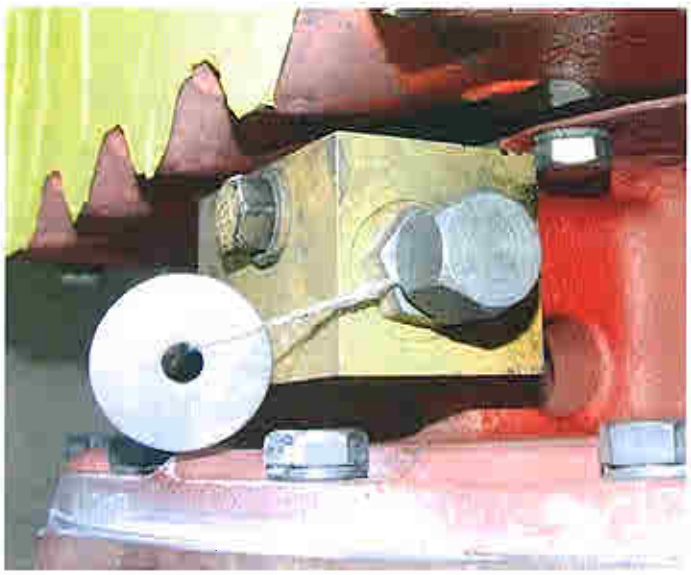

Figure 8 – Block on the Oil Inlet – View 3

A part number (2W3790) was stamped in the side of the Block Assembly, as noted in Figure 9. There was an indication in the "Customer Driven" database, for Finning Work Order 0805069 that a 2W3790 Flange had been purchased on the Seg 03 Parts List, on 17 / Apr / 2009.

The oil passage in the Block Assembly (Figure 10) had a slightly elongated appearance.

Figure 9 – Block Assembly Identification

Figure 10 – Block Assembly – O-ring and Oil Port

The outline / pattern surrounding the oil inlet port in the Centre Bearing Housing suggest the oil port in the Block Assembly, and the oil port in the Centre Bearing Housing, had been aligned during operation.

Figure 11 – Centre Bearing Housing – Oil Inlet Port

During the disassembly process, it was noted that the surfaces of the various Compressor End sub-components (Figure 12) were very heavily coated with soot deposits. This material was easily smudged when touched with a finger.

Figure 12 – Compressor End View

The Turbine End sub-components were heavily coated with exhaust gas debris and a soot deposit, as noted in Figure 13.

Figure 13 – Turbine End View

The Thrust surface on the Compressor Wheel was lightly scratched, with some light, localized scoring, as noted in Figure 14.

The Compressor End Oil Control Ring (Figure 15) had a slight wear groove on the inside perimeter. There was no such groove on the Turbine End Oil Control Ring.

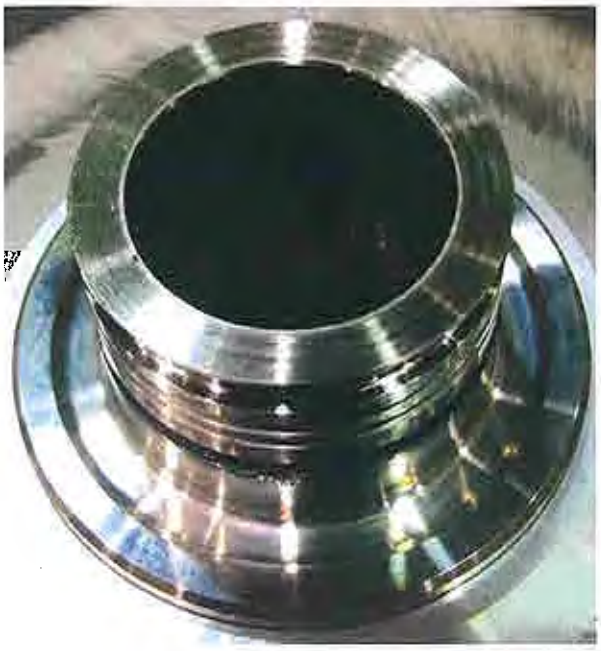

Figure 14 – Compressor Wheel Thrust Surface

Figure 15 – Compressor End Oil Control Ring

The leading edges of the Compressor Wheel blades (Figure 16) were lightly pitted and track marks were extending from those locations.

Figure 16 – Compressor Wheel Blades

The internal sub-components, such as the Thrust Bearing (Figure 17) and the Compressor End Bearing Holder and associated parts (Figure 18) were coated with a very dark oil residue, containing very fine contaminants.

Figure 17 – Thrust Bearing

Figure 18 – Compressor End Bearing Assembly

The thrust surface for the Compressor Wheel, on the Compressor End Bushing Holder (Figure 19) was lightly scored.

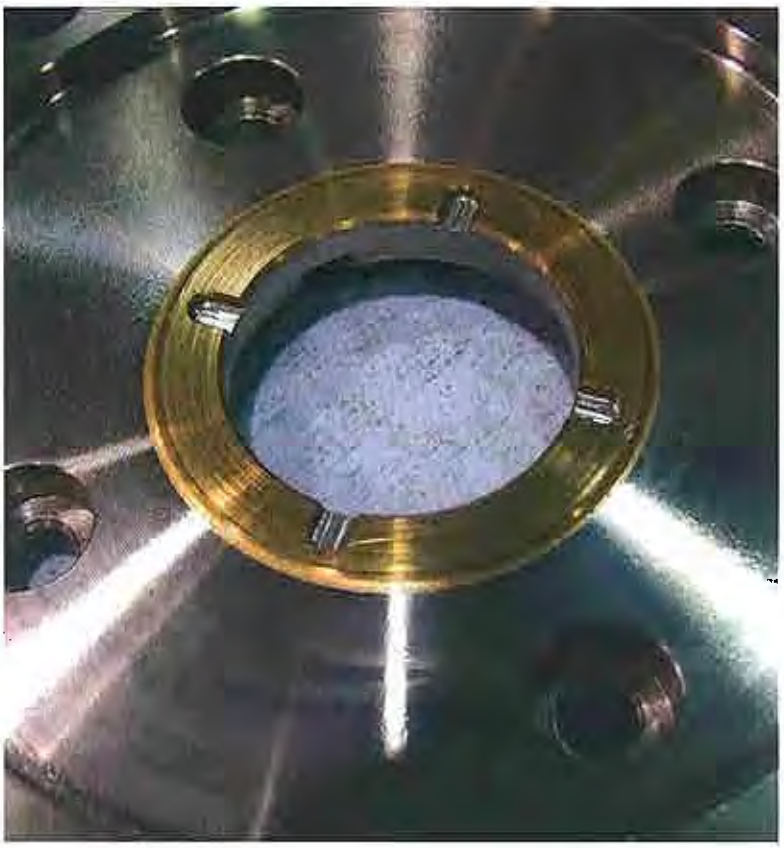

Figure 19 – Compressor End Bushing Holder – Upper Side - View 1

The surfaces of thrust pads on the Bushing side of the Compressor End Bushing Holder (Figure 20) were lightly scored.

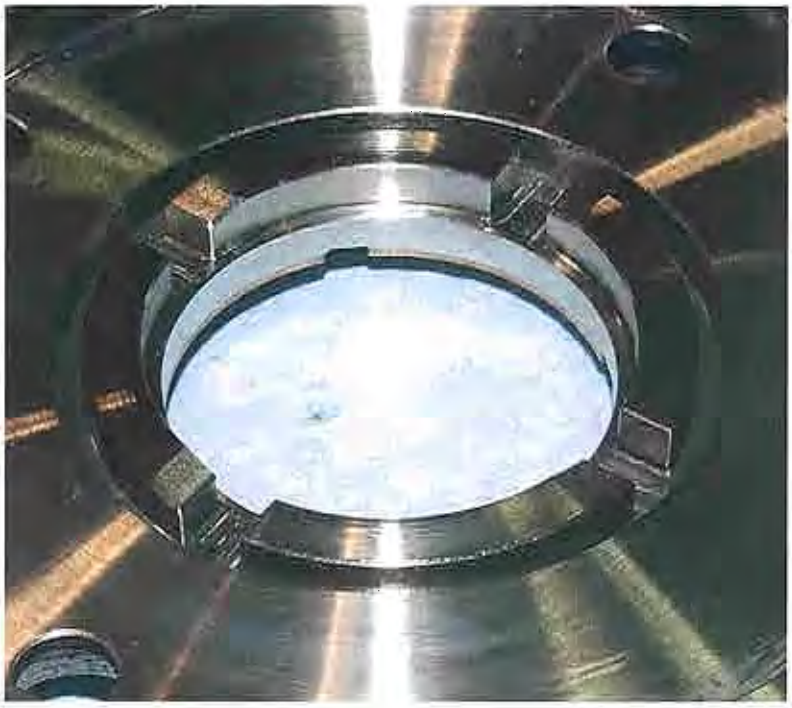

Figure 20 – Compressor End Bushing Holder – Upper Side - View 2

The surface of the Thrust Bearing (Figure 21) was lightly scratched, with some light, localized scoring.

Figure 21 – Thrust Bearing

The mating thrust surfaces on the Compressor End Bushing Holder (Figure 22) were also lightly scratched.

Figure 22– Compressor End Bushing Holder – Lower Side – View 1

The bearing surfaces in the Compressor End Bushing Holder (Figure 23) were lightly scored.

Figure 23– Compressor End Bushing Holder – Lower Side – View 2

The outer surface of the Compressor End Bushing (Figures 24 & 25) was lightly scratched with a few light, localized score marks.

The thrust surfaces (sides) of the Bushing were lightly scratched (Figure 24) to lightly scored, as noted in Figure 25. The scoring could barely be detected with a fingernail.

Figure 24 – Compressor End Bushing – View 1

Figure 25 – Compressor End Bushing – View 2

The inner surface of the Compressor End Bushing (Figures 26 & 27) was lightly discoloured and lightly scored.

Figure 26 – Compressor End Bushing – View 1

Figure 27 – Compressor End Bushing – View 2

The surfaces of the thrust pads in the Turbine End Bushing Holder (Figure 28) were lightly scored.

The bearing surfaces in the Bushing Holder (Figure 29) were heavily scored.

Figure 28 – Turbine End Bushing Holder - Upper

Figure 29 – Turbine End Bushing Holder - Lower

The outer surface of the Turbine End Bushing (Figures 30 & 31) was heavily scored.

The thrust surfaces (sides) of the Bushing were lightly scratched (Figure 30) to lightly scored, as noted in Figure 31. The scoring could barely be detected with a fingernail.

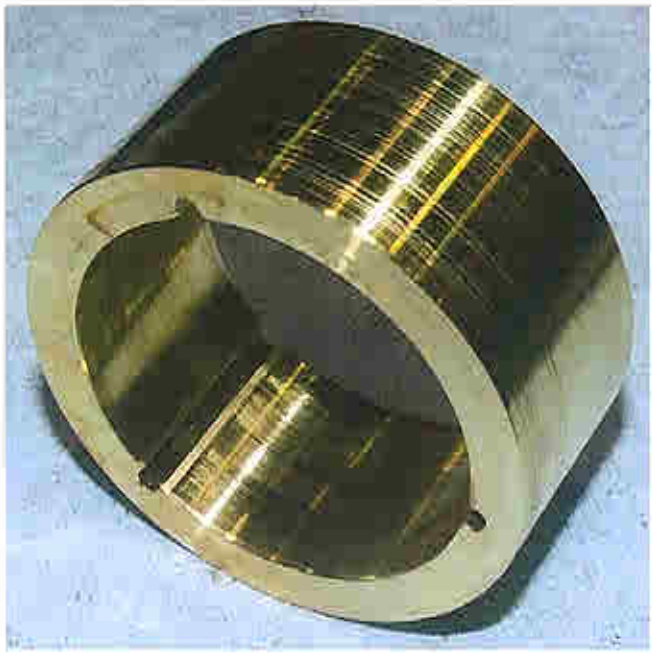

Figure 30 – Turbine End Bushing – View 1

Figure 31 – Turbine End Bushing – View 2

The inner surface of the Bushing (Figures 32 & 33) was lightly discoloured and lightly-to-moderately scored.

Figure 32 – Turbine End Bushing – View 1

Figure 33 – Turbine End Bushing – View 2

The bearing surfaces on the Turbine Wheel and Shaft Assembly (Figure 34) were heavily discoloured and lightly scratched-to-lightly scored.

While the Turbine End bearing surface was heavily discoloured, there were few signs of coking activity on the Shaft side of the Turbine Wheel, as noted in Figure 35.

Figure 34 – Turbine Wheel and Shaft Assembly

Figure 35 – Turbine End

The surfaces of the Turbine Wheel blades, on the trailing side, were lightly-to-moderately coated with exhaust gas debris, as noted in Figures 36 & 37.

The deposits on the blades were slightly uneven.

Figure 36 – Turbine Wheel Blades - Trailing Side View - 1

Figure 37 – Turbine Wheel Blades - Trailing Side View - 2

There were signs that light rubbing contact had occurred, at some time(s), on the ends of the Turbine Wheel blades, as noted in Figures 38 & 39.

Some of the exhaust gas deposits that had re-coated the ends of the blades were flaking off.

Due to the uncertainty about the degree of rubbing contact, the Turbine Wheel and Shaft Assembly will require in-depth cleaning and inspection to ensure it is suitable for salvage and / or re-use.

Figure 38 – Turbine Wheel Blades – End View - 1

Figure 39 – Turbine Wheel Blades – End View - 2

The surfaces of the Turbine Wheel blades, on the leading side (Figures 40 & 41) were moderately-to-heavily coated with exhaust gas debris.

There were signs that extensive flaking activity had occurred during operation.

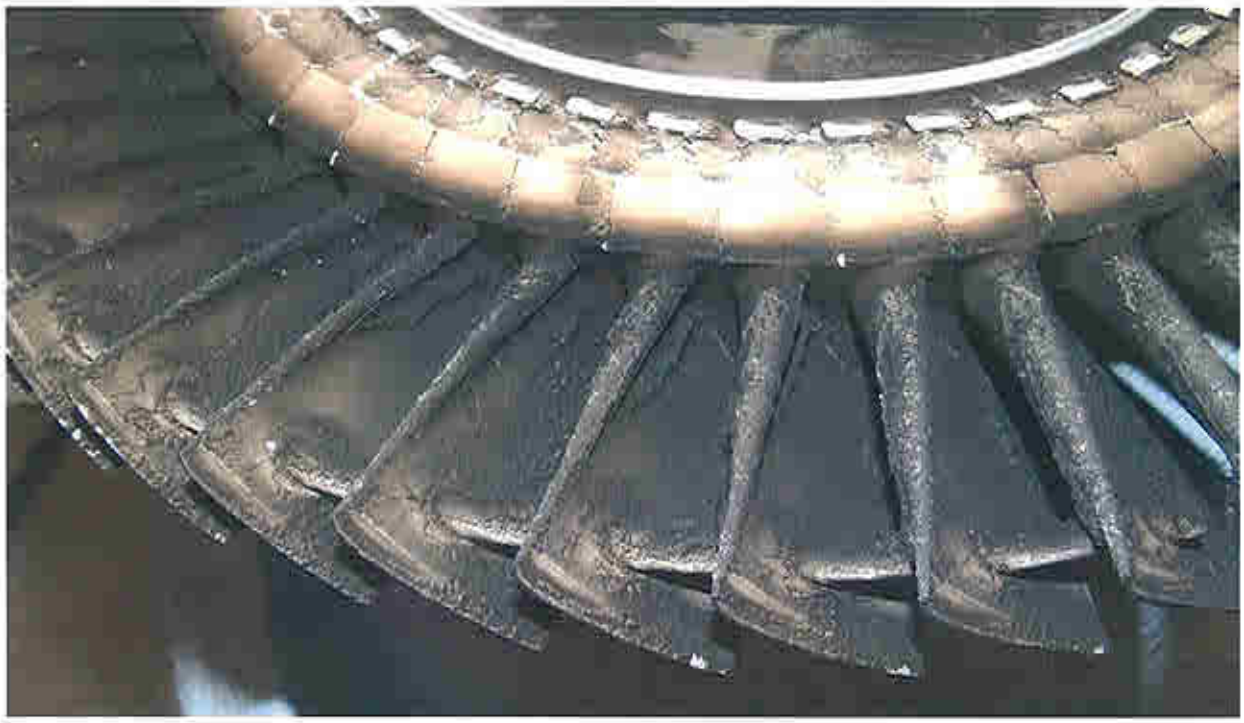

Figure 40 – Turbine Wheel Blades - Leading Side View - 1

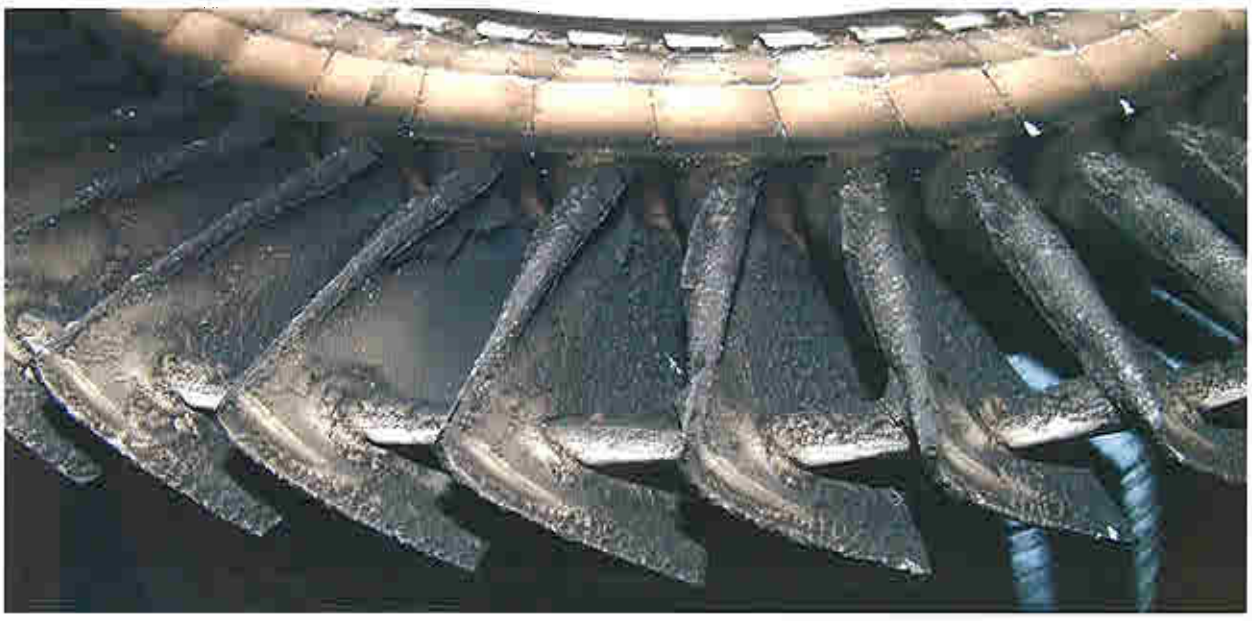

Figure 41 – Turbine Wheel Blades – Leading Side View – 2

During the cleaning process, it was noted that the cooling passage in one of the side Covers on the Turbine Housing had eroded to the point the surface had opened, as shown in Figures 42 & 43.

Figure 42 – Cooling Passage Damages – View 1

Figure 43 – Cooling Passage Damages – View 2

SUMMARY

The Customer had indicated that the recent Turbochargers on this Engine had experienced problems. The exact nature and origin of the problem(s) was still uncertain. While there were signs of non-typical issues, for the number of hours in service, a single area of concern within the Turbocharger could not be identified; in general, the Turbocharger was not a problem.

The turbocharger has an usual level of build-up of materials at the Compressor End, and at the Turbine End; coupled with the very dark oil residue and the inconsistent bearing surface wear patterns.

The amount of discolouration noted on the bearing surfaces on the Turbine Wheel and Shaft Assembly indicates this Turbocharger had experienced high temperatures at some time(s) during operation. However; there were no signs to suggest the Turbocharger had experienced instances of hot shut downs. In addition; the relative lack of coking deposits at the Turbine End, suggest the instances of high temperature operation had been infrequent and / or not prolonged events.

The erosion of the cooling passage in the one side Cover on the Turbine Housing is highly unusual considering this Turbocharger appears to have been a NEW component, or has only had one re-build (given the single previous Work Order number stamped on it). This erosion raises questions as to the quality / condition of the coolant / coolant conditioner package.

Given the length of time that this Turbocharger has been in operation (6549 hours) the degree to which the surfaces of the Compressor End sub-components are coated with a soot deposit would be considered as unusual.

The fact that the Compressor End Oil Control Ring is slightly grooved is also unusual for this amount of time in operation. However; when checked for fit in the Compressor Wheel and in the sealing bore in the End Cover, there were no signs to suggest the ring gap was excessive, or the fit was incorrect.

There were no signs of damages to the sealing groove in the End Cover, or to the O-ring used in that location.

The wear on the Compressor End Oil Control Ring may have also been influenced by vibration; since the flaking activity noted on the Turbine Wheel was quite significant, and it is quite likely that the Rotating Assembly had been operating in an unbalanced condition at some time(s) during operation.

The wear beginning on the one side of both of the Shaft Bushings is significant; for the limited amount of time in operation, and tends to confirm vibration(s) was / were occurring due to imbalance(s) in the Rotating Assembly, at some point in time.

The Compressor End Oil Control Ring may have also experienced some wear due to the fine contaminants in the Turbocharger oil supply. When opened for disassembly, the oil residue coating the various internal sub-components was quite dark and likely contained very fine abrasives. The generalized scratches, and light scoring, would suggest the oil supply, over time, was lightly contaminated with fine wear particles.

Given the length of time in operation, the degree to which the various Turbine End sub-components were heavily coated with exhaust gas debris, is also unusual.

In general, the various bearing surfaces at the Compressor End were lightly scratched-to-lightly scored however; the surfaces of the Turbine End Bearing surfaces were significantly more scored. Even with a lightly contaminated oil supply, it would be expected that due to the design of the oil passages in the Centre Bearing Housing (Figure 44) the Compressor End bearing surfaces might be the ones to experience slightly heavier wear.

Given the uncertainties surrounding this Turbocharger, a review of the "Customer Driven" database for this serial number Engine (8RB00292) was conducted.

On 01 / Mar / 2010 (134940 hours – Finning WO 0805702 – OEM WO 89851) a Work Order was opened to troubleshoot for low compression in the #2 and the #3 Cylinders.

Considering the layout of the Exhaust Piping (Figure 47) and assuming the Engine has a standard rotation with a firing order of 1-5-3-6-2-4, it can be seen that a problem with the #2 and the #3 Cylinders could cause a significant difference in the power impulses sent to each port in the Split Exhaust Inlet Housing (#1 – Strong; #5 Strong; #3 –Weaker; #6 –

Strong; #2 – Weaker; #4 – Strong). In essence, the one port in the Split Housing would only receive one strong impulse in comparison to the three strong impulses acting on the port on the other side.

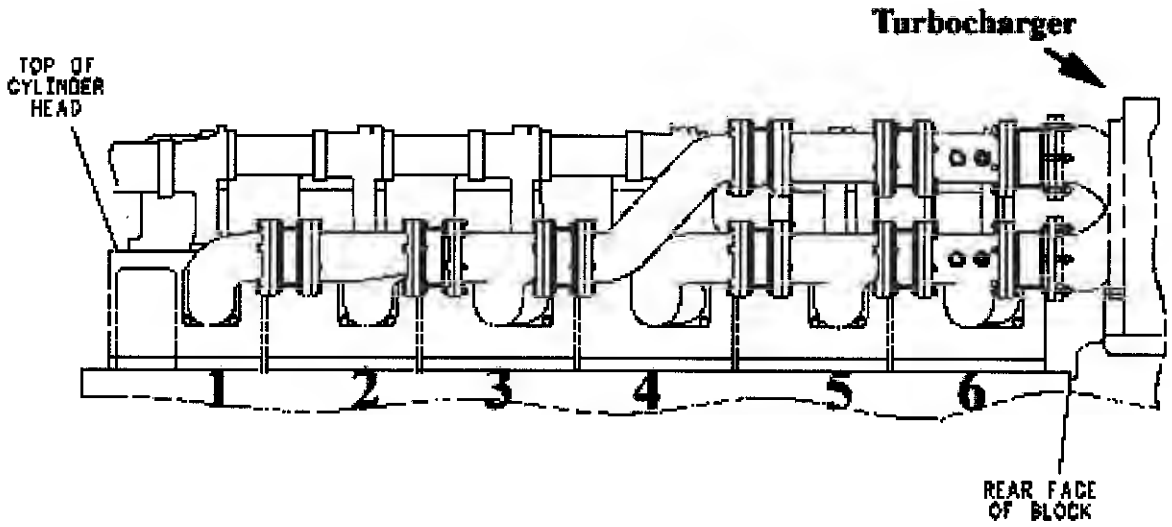

Figure 47 – Engine Exhaust Piping to Turbocharger Exhaust Gas Inlet Split Housing (SIS Drawing Modified for Use)
Any significant difference in the power impulses sent to each port in the Split Exhaust Inlet Housing noted above, would continue to act unevenly on the Turbine Wheel, as seen in Figure 48.

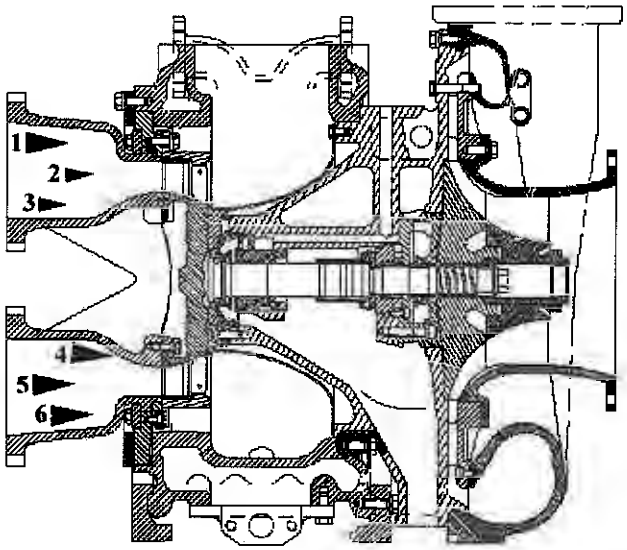

Figure 48 – Turbocharger Exhaust Gas Inlet Split Housing (SIS Drawing Modified for Use)

On 11 / Jan / 2010 (zero hours noted – Finning WO 0805604) a Work Order was opened to address a number of issues, including (Seg 03) - Inspect Turbo for possible carbon build-up. The Parts List indicates the 1338081 Gaskets were replaced. These Gaskets are used between the Exhaust Manifold and the two Ports on the Turbocharger Exhaust Gas Inlet Split Housing. This suggests the Field Technician had inspected the Turbine Wheel Blades through the Exhaust Gas Inlet Ports. There were no notes on that Work Order to indicate the amount, or severity, of any carbon build-up.

There was also mention (Seg 04) – Repair Water Manifold. It is not known if this repair was in relation to a coolant / coolant conditioner problem that might help explain the erosion problem found in the side Cover in the Turbocharger.

On 08 / Jul / 2009 (zero hours noted - Finning WO 0805254) a Work Order segment (02) was opened "for OEM charges to perform failure analysis of turbo". A review of the OEM Work Order Tracking database could find no OEM Work Order that related to this Finning Work Order. The e-mails associated with the present Turbocharger suggest the failure analysis may have involved the previous Turbocharger on the Engine, and it is possible that ABB (Vancouver ?) may have performed the failure analysis.

A number of parts, including the Nozzle, were purchased, and credited back on the Parts List for Finning WO 0805254. This suggests there had been an expectation of doing some work on the Turbocharger, but that plan had changed.

On 05 / May / 2009 (zero hours noted – Finning WO 0805118) a Work Order was opened to replace a failed Injector. The Parts List indicates this was a 10R1252 Injector Group which was under warranty.

Three SIS Engine News articles relate to the 10R1252 Fuel Injector. Media Number SEBD9322-00 – Date Updated 01 / 06 / 2003 "Adjust the Timing Dimension for the New Fuel Injector Groups" includes mention of a change in Engine Timing to 2.5 degrees retarded.

In that same Engine News, there is mention that the article has been replaced by the following: Engine News, SEBD9317, "New Fuel Injector Groups are Used". There is no mention of a change to the Engine Timing specification.

In Media Number SEBD9327-00 – Date Updated 01 / 11 / 2003 "New Fuel Injector Groups are Used" there is also no mention of a change to the Engine Timing specification.

The difference in information raises the question of whether the Engine Timing has / had been changed, or not, and if the differences would have been a factor in the present Turbocharger problems.

On 30 / Mar / 2009 (zero hours noted – Finning WO 0805069) mention is made of a Turbocharger failure. A review of the OEM Work Order Tracking database could find no OEM Work Order that related to this Finning Work Order. It then appears that the failed Turbocharger under discussion on Finning WO 0805069 was replaced by the present Turbocharger (OEM WO 89851).

The Turbocharger had unusually high levels of soot deposits on the surfaces of the various Compressor End sub-components, as well as a heavy build-up of exhaust gas debris on the Turbine End sub-components. Heavy and uneven flaking of debris from the Turbine Wheel blades had caused the Rotating Assembly to operate in an unbalanced state, at time(s) during operation. While light Wheel rub had occurred, no sub-components were broken. There were no identifiable problems associated with this Turbocharger however; a number of external factors have been identified and it is likely that one, or more, had been factors in the failure of this Turbocharger.

Yukon Electric Watson Lake D3606 Inspection Findings

During the week of July 5 to July 9, 2010, I performed an observation on the operational practices of Yukon Electric Corporation and an inspection of the mechanical workings of the D3606, serial # 8RB00292 on location at the Watson Lake Power Generating Station in Watson Lake, YT, here is an overview into those findings.

Upon meeting with operations there were discussions on the concerns with the unit and the ability to maintain the availability of the unit to meet the customers' needs. The concerns noted were:

- turbo oil seal failure as well as possible soot intake
- higher than normal cylinder temperature differentials
- turbo stall noted in some instances, not seen with the unit since new
- various coolant leaks
- high oil consumption, and the carbon build up associated with this
- maintenance and operational practices

Looking through the operations records onsite, it was noted that the customer records daily operation parameters for all units on site, as well as oil added, and any deficiencies/ repairs that need to be, or will be performed. The routine performed during the 5 days onsite did not deviate from day to day other than the times performed, which were never more than a ½ hr difference from day to day. The amount of operational parameters recorded was very good to provide a baseline for all units and for being able to monitor and pick out possible issues with the units. Scheduled maintenance for the units appeared to have been performed on the recommended intervals and only some issues with the recommended cooling system maintenance have been overlooked in the past, but have appeared to be back on track. No issues were noted with operations at the power house with the existing equipment and layout of the powerhouse, although there could be some improvements made to the power house.

The records for the D3606 onsite, unit 4, were for the last two years since the last major overhaul, it was seen that there were issues with coolant leaks, high oil consumption at times, as well as turbo stall problems and varying cylinder temps. After removal of the turbo charger for repair, the after cooler was removed from the unit for inspection. It was seen that a considerable amount of oil has been going through the after cooler core from the turbo charger, and substantial amounts can be seen in the pictures taken of the air box and after cooler core and housing. This issue of oil being pushed through the intake from the turbo, would not have given true oil consumption data for the customer on a daily basis, so until this issue is rectified, the oil consumption reports will not be as accurate as one would expect but it is not being suggested that the sole cause for excessive oil consumption is being caused by the turbo oil seals since it has been seen in some instances after newer piston and liner groups have been installed in other units that it has taken up to 10000hrs for a break in period . Also the fact that the system used by the customer for adding oil, is only as accurate as the operations staff performing the adding, since there is no auto oil make up system with flow counters, which can also count for some discrepancy.

With the after cooler off of the unit, a boroscope of the intake valves was performed and photographs taken. It was seen that there was a substantial amount of carbon deposits on the head of the valves as well as there was evidence of carbon breaking off, which has already caused a torched valve on the unit in one instance, and this may also create further problems in the future with similar issues. The build up of carbon was not a surprise with the amount of oil found in the air box, and with the turbo oil seal issues. The after cooler core, air box and after cooler housing were cleaned before being reinstalled on the unit, as seen in the photographs.

The injectors were also removed from the unit to allow for a boroscope and inspection of the cylinders and piston tops for carbon buildup as well. Upon inspection it was noted that carbon deposits were evident on both the bottom of the cylinder heads around the valve faces as well as on the top of the pistons, but again no a surprise knowing the fact of the turbo oil seal issues, and as on the inside of the heads, evidence of carbon breaking off can be seen in the photographs. Disassembly of the engine and cleaning of the related components which are seen to have carbon build up, would most likely extend the life expectancy of those parts, but the unit would possibly make it to the next overhaul interval without major issues, assuming that the oil consumption issue is alleviated with the turbo repair.

The issue of varying cylinder temperatures between cylinders may be more than one issue. It would be in my opinion that the quality of fuel has nothing to do with the issue, but rather issues with the possible wrong turbo group installed, causing less than normal boost pressures as well as some slight wear in the linkages which can cause a variation in cylinder temperatures. The unit can be tuned to match up cylinder temperatures by adjusting the individual synchronization for each injector, therefore ensuring all cylinders run at the same temps, as long as the pyrometer for each cylinder is accurate, and only small adjustments are made to make up for small amounts of linkage wear. Once the linkage is worn past spec it still requires replacement. The injectors did have a small amount of carbon on them, but it was easily wiped off with a cloth, and from previous experience is found on units idling down with cool intake temps, causing a slight incomplete burn, but usually is burnt off when loaded up. When the injectors were reinstalled into the unit, the original timing spec of 117.8mm was used just for trial purposes to see if a slightly advanced timing will help the cylinder temps come closer together, valve lash, bridge adjustments and rack synchronization were also performed at this time.

The group number of the turbo charger, 7E9669, was noted during removal of the turbo, and when checked against the original turbo group number which updated to 7E9668, was found to be the incorrect group for this application, according to a response from the TC department. The 7E9669 turbo group is found used on a 1000rpm marine application, where as the 7E9668, is used in the 900rpm EPG application. After a quick look at a parts consist of both groups, the only difference appeared to be the nozzles used between them, which could explain the issues the customer is having with turbo stall and as stated earlier, may have an effect on cylinder temperatures due to different boost pressures, and although the TC department suggests that the boost pressures would be higher with the 7E9669 turbo, without running the unit to confirm, this would just be speculation.

As far as the issue with the oil seals leaking on the turbo, there were some concerns that the orifice in the oil block for the turbo oil feed line may be too large for the turbo, but I would have to question that, as the oil block is the same one from the original installation, and the unit does have 135000hrs, and also there appeared to be no issue before the turbo was installed. The prelube pressure cutout switch was also checked to ensure the pressure was within spec, and upon testing the switch with a regulator and air pressure to slowly raise the pressure, as well as with the prelube pump and a gauge at the turbo feed block, both instances produced after several tests, the same pressure of 19KPA, which is well within spec. The reason for the seals failing is still undetermined at this time, and it may be that the turbo had faulty seals to begin with, or from thermal shock from cold intake air temperatures, or it could have been from a build up of carbon deposits on the turbine wheel causing an imbalance from excessive oil consumption from the break in period, since this unit has no turbo wash system, but that is just speculation.

The intake piping was inspected for signs of soot intake, but no evidence was found. The soot may be caused by the centrifugal force of the turbo compressor wheel spinning, and just like a centrifuge, only the soot is left. It is in my opinion that this should correct itself after the turbo repairs. The intake piping also has a manual adjusting door to allow the customer to blend the intake air during cold outside ambient air temps which may also explain some of the soot due to small exhaust leaks on other units, although functional, it does seem small to allow for the proper amount of air flow to maintain a warmer air intake temperature, but again age of the system proves that although it could be improved upon, there has not been issues with the system in the past.

Coolant leaks with the unit due to the cylinder block repairs performed during the overhaul are being addressed and a solution is forthcoming. Other small leaks that appear to be from seals and connections, in my experience are typical with the use of extended life coolant in older units, and especially if the unit does not run continuously. Once the unit is able to run more consistently, the issues should be less evident over time.

It is in my opinion that while the facility has been there for some time now that improvements to the air flow through the building should be looked at. I would suggest improving the cooling air flow through the generators to allow for decreased temperatures in the building as well as within the generators. Air flow through a generator is from rear to the flywheel, airflow through the building is across the building from unit 1 to unit 6, depending on the units online, the air flow past unit 6 is substantially higher than that of unit 1. Exhaust fans on the long wall in front of the engines as well as the addition of cold air intakes across the long wall behind the units would definitely increase cooling efficiency of the building, but placement may be an issue due to existing equipment. It would bring down winding and bearing temperatures in the warm months, as well as allow more air in the building in the colder months to blend with, also decreasing the premature wear of components due to heat. It would also be a suggestion to install a newer style drain on the 3500 series units to allow for better extraction of waste oil from the crankcase, leaving less residual oil during oil changes, as well as it may also be beneficial to look into installing a oil make up system with flow counters on each unit to track oil consumptions more accurately. Also the installation of an auto blending air intake system for the 3606 would reduce turbo surge during cold weather and assist with recycling of the air within the building, but again these are just suggestions.

When reviewing this report, please refer to the photographs taken with the digital boroscope as well as a digital camera. All photographs are labeled to assist with identification of components.

Brian Brent
Field Service Technician
Finning (Canada)

2007

Sep	121712 hrs	Major overhaul

2008

May 20	122726 hrs	#4 cylinder, injector repair
Jul 02	123572 hrs	#3 cylinder, injector repair
Oct 22	126150 hrs	oil leak at intake side of turbo, report to Finning

2009

Mar 28	128130 hrs	unit shutdown by operators due to metal on metal noise and high crankcase pressures
Apr 11		Finning on site inspection found that the turbo was rubbing on the housing, on the cold side, and that there was play in the shaft. Turbo was sent out for repair.
Apr 16		Finning installing a brand new turbo
Apr 21	128252 hrs	#1 cylinder, injector repair
Apr 27	128390 hrs	block repairs due to excessive glycol leak when shutdown
Jul 15	129746 hrs	Finning in for tune-up and to investigate exhaust side of turbo and high temp readings on cylinder #1 and stack
Oct 06	131583 hrs	repair coolant leak at turbo
Oct 27	132077 hrs	#6 cylinder, injector repair
Dec 13		noted that turbo was stalling, air intake mix was adjusted
Dec 23	133436 hrs	#5 cylinder, injector repair

2010

Jan 09	133844 hrs	Finning in for tune-up and turbo inspection due to issue with turbo stall. No definitive answer to cause.
Mar 01	134940 hrs	Turbo issues result in unit being out of service. Finning inspect #2 and #3 cylinder for low compression, #2 cylinder and injector repair, turbo removed and sent to OEM.
May 20	135252 hrs	#4 cylinder, injector repair
Jun 03		oil leak at intake side of turbo. Finning notified
Jun 08		presence of oil in airbox confirmed. Unit shutdown as this is a continuation of major issue with turbo.
Jul 05		Brian Brent (Finning Power Systems) was in the plant inspecting and testing Unit #4
Jul 07		turbo removed and eventually sent to Whitehorse to determine cause of oil leak and repair.
Aug 09		turbo re installed, however oil leaking resumed.
Aug 13		turbo removed and sent to ABB for independent testing and evaluation.
Oct 22		turbo re installed, Finning ran tests on it over 7 day period. Test showed operating parameters to be normal. Turbo still leaking, result is questionable reliability of unit.

List of Forced Projects 2008 to 2012

Project Name	Project Categoy	Appropriation Type	2008	2009	2010	2011	2012
Campbell Highway Relocation	Forced	Distribution Improvements	$ 43,000				
Cadet Camp Three Phase Service System Improvement	Forced	Distribution Improvements	$ 83,000				
System Upgrades Lot 1378/79 Range Road	Forced	Distribution Improvements	$ 93,000				
Carmacks Upper Bench Rerouting	Forced	Distribution Improvements	$ 31,000				
Connect Pelly Crossing into Yukon Interconnected System	Forced	Distribution Improvements	$ 435,000				
Paddlewheel Line Relocation	Forced	Distribution Improvements	$ 30,000				
Whistlebend 34.5kV Substation Distribution Lines	Forced	Distribution Improvements			$ 492,000	$ 156,000	
Whistle Bend Substation	Forced	Distribution Improvements				$ 1,690,000	$ 423,000
Wickstrom Road Line Relocation for Whitehorse General Hospital Residence and Medical Building	Forced	Distribution Improvements		$ 83,000			
Pole Removal Wickstrom Road	Forced	Distribution Improvements			$ 25,000		
Nordenskiold River Bridge Rerouting	Forced	Distribution Improvements			$ 42,000		
Takhini North Upgrade	Forced	Distribution Improvements			$ 134,000		
Watson Lake 3-Phase System Protection Upgrade	Forced	Distribution Improvements			$ 100,000		
Mount Sima Subdivision	Forced	Distribution Improvements			$ 42,000		
Configure Pelly Substation to Yukon Interconnected System	Forced	Distribution Improvements				$ 23,000	
Line Upgrade and Relocation Army Beach	Forced	Distribution Improvements				$ 92,000	
Line Relocation Eagle Way	Forced	Distribution Improvements				$ 30,000	
Hotsprings Road Upgrade	Forced	Distribution Improvements				$ 190,000	
Line Upgrade and Relocation Lot 56 Paint Mountain	Forced	Distribution Improvements				$ 69,000	
Centennial Street Upgrades	Forced	Distribution Improvements				$ 20,000	
System Upgrade, Extension of 5L628 to Grizzly Valley	Forced	Distribution Improvements				$ 454,000	
5L626 Double Circuit Line to Whistle Bend Substation	Forced	Distribution Improvements				$ 200,000	
PCB Identification and Transformer Change Outs	Forced	Distribution Improvements				$ 239,000	$ 401,000
5L628 Crestview to Mayo Road Corner Double Circuit	Forced	Distribution Improvements					$ 628,000
Shipyard's Substation Transformer Failure and Upgrades	Forced	Distribution Improvements					$ 473,000
Laberge Substation Upgrade	Forced	Distribution Improvements					$ 57,000
Range Road Line Rerouting	Forced	Distribution Improvements					$ 56,000
System Improvements Lowe Street	Forced	Distribution Improvements					$ 21,000
Pelly Crossing Tie into Transmission Grid	Forced	Generation	$ 92,500				
Fish Lake Control Room Monitor Upgrade	Forced	Generation		$ 52,000			
Fish Lake Incremental Purchase Power	Forced	Generation		$ 69,000			
Fish Lake Unit #1 Spillway	Forced	Generation			$ 212,000	$ 26,000	
Fish Lake Unit # 1 Turbine and Building Replacement	Forced	Generation				$ 717,000	$ 1,024,000
Hobo for Franklin Lake Water Monitoring	Forced	Generation				$ 36,000	
Hobo Water Monitor for Fish Lake at Range Road	Forced	Generation				$ 22,000	
Stewart Crossing Radio Replacement and Programmable Logic Controller (PLC) Upgrade for Remote Control	Forced	Generation				$ 30,000	
Fish Lake Unit # 1 Tailrace Reconstruction	Forced	Generation				$ 173,000	
Carmacks Fuel System Upgrade	Forced	Generation					$ 100,000
Water Pressue Monitor (Hobo) for Louise Lake	Forced	Generation					$ 37,000
Ross River Fuel System Upgrade	Forced	Generation					$ 37,000
Teslin Fuel System Upgrade	Forced	Generation					$ 41,000
Destruction Bay Fuel System Upgrade	Forced	Generation					$ 21,000
Haines Junction Fuel System Upgrade	Forced	Generation					$ 20,000
Meters General	Forced	Meters	$ 31,000		$ 460,000	$ 199,000	$ 283,000
Miscellaneous O/H Services - Various Subdivisions	Forced	New Extensions	$ 1,304,000	$ 969,000	$ 1,022,000	$ 1,274,000	$ 992,000
Miscellaneous New U/G Services	Forced	New Extensions	$ 95,000	$ 36,000	$ 86,000	$ 216,000	$ 144,000
Land Rights	Forced	New Extensions	$ 100,000	$ 56,000	$ 66,000	$ 72,000	
General Drafting and Mapping	Forced	New Extensions	$ 46,000	$ 75,000			
Mount Sima T-Bar	Forced	New Extensions				$ 86,000	
Lot 16 Marwell Subdivision	Forced	New Extensions	$ 53,000				
Whitehorse Cadet Camp Three Phase Service	Forced	New Extensions	$ 40,000				
Mountain Air Subdivision	Forced	New Extensions	$ 317,000				
Little Atlin Feeder Tap	Forced	New Extensions	$ 178,000				
4th Ave and Strickland Condominiums	Forced	New Extensions	$ 92,000				
Hamilton Boulevard Main Infrastructure Extension	Forced	New Extensions	$ 266,000	$ 100,000			
Yukon Government Whitehorse Copper Phase II	Forced	New Extensions	$ 262,000				
Stan McCowan Subdivision	Forced	New Extensions	$ 126,000				

List of Forced Projects 2008 to 2012

Project Name	Project Categoy	Appropriation Type	2008	2009	2010	2011	2012
Ta'an Kwach'an Council Subdivision - Klondike Highway North	Forced	New Extensions		$ 60,000			
New Customer Connection at Minto Crossing	Forced	New Extensions	$ 40,000				
Takhini North Infill	Forced	New Extensions		$ 341,000	$ 312,000		
Skookum Asphalt Plant	Forced	New Extensions	$ 61,000				
Burns Road Lot Development	Forced	New Extensions		$ 86,000			
Arkell Subdivision Infill	Forced	New Extensions	$ 78,000	$ 717,000			
Yukon Government Carmacks Sewer Treatment Plant	Forced	New Extensions		$ 32,000			
Whitehorse Lot 1097	Forced	New Extensions		$ 46,000			
Lot 10 Centennial Street	Forced	New Extensions	$ 28,000				
City of Whitehorse Public Safety Building	Forced	New Extensions		$ 61,000			
Carcross Tagish First Nation Carcross Line Rerouting	Forced	New Extensions	$ 32,000				
Champagne Aishihik First Nation Subdivision	Forced	New Extensions		$ 36,000			
Connection of Minto Landing into Yukon Interconnected System	Forced	New Extensions	$ 47,000				
Two City Water Wells in Riverdale	Forced	New Extensions		$ 107,000			
New Whitehorse Correctional Centre	Forced	New Extensions		$ 90,000			
Yukon Government Carcross Water Front Place	Forced	New Extensions		$ 35,000			
Yukon Government New Airport Parking Area	Forced	New Extensions		$ 58,000			
Whitehorse General Hospital Staff Residence	Forced	New Extensions		$ 32,000	$ 30,000		
35 Unit Condominium Wann Road	Forced	New Extensions		$ 53,000			
Yukon Housing 8-Plex	Forced	New Extensions		$ 88,000			
Selkirk First Nation Child Care Center	Forced	New Extensions		$ 36,000			
Yukon Government Army Beach Sweage Lagoon	Forced	New Extensions		$ 47,000			
Takhini Lot 1371	Forced	New Extensions		$ 33,000			
Watson Lake Line Move	Forced	New Extensions		$ 35,000			
Teslin Seniors 8-Plex	Forced	New Extensions		$ 40,000			
Northwestel Communication Tower Hotsprings Road	Forced	New Extensions		$ 27,000			
Haines Junction Cultural Centre	Forced	New Extensions			$ 74,000		
Lower Post Health Center 3 Phase Line	Forced	New Extensions			$ 733,000		
Lot 1095 Gentain Lane	Forced	New Extensions		$ 41,000			
Lot 1018 Main Street	Forced	New Extensions			$ 42,000		
Yukon College	Forced	New Extensions			$ 57,000		
Yukon Government Haines Junction Willow Acres Residential Infill	Forced	New Extensions			$ 37,000	$ 124,000	
Yukon Government Core Library	Forced	New Extensions			$ 59,000		
New Country Residential Subdivision in Haines Junction	Forced	New Extensions			$ 105,000		
Yukon Housing Seniors Housing - Jeckell Street	Forced	New Extensions			$ 44,000		
10 Units on Range Road	Forced	New Extensions			$ 46,000		
Lot 40 Mount Sima	Forced	New Extensions			$ 22,000		
Kwanlin Dun First Nation Cultural Centre	Forced	New Extensions				$ 31,000	
35 Unit Condominium Near Mountain Air Subdivision	Forced	New Extensions			$ 50,000		
Main Street Condominium	Forced	New Extensions			$ 45,000		
Yukon Government - Yukon River Crossing Study and Design	Forced	New Extensions			$ 43,000		
Whistle Bend Subdivision Stage 1 & 2	Forced	New Extensions				$ 1,242,000	$ 683,000
Yukon Gardens Subdivision	Forced	New Extensions			$ 59,000		
Lot 1100 Tagish	Forced	New Extensions			$ 29,000		
Carcross Landfill	Forced	New Extensions			$ 33,000		
Stan McCowan 12-Plex	Forced	New Extensions			$ 59,000		
Crestview Booster Station	Forced	New Extensions			$ 29,000		
Whitehorse Water Front Place Line Relocation	Forced	New Extensions			$ 73,000		
Little Salmon Carmacks First Nation Healing Centre	Forced	New Extensions			$ 21,000		
Marsh Lake Landfill	Forced	New Extensions			$ 64,000		
Grove Street New Lots	Forced	New Extensions			$ 35,000		
Diamond Ranch Extension	Forced	New Extensions				$ 130,000	
River's Edge Development	Forced	New Extensions				$ 81,000	
25 Wann Road - 65 Units	Forced	New Extensions				$ 343,000	
Yukon Government Yukon River Crossing	Forced	New Extensions					$ 62,000
Eagle Eye Subdivision	Forced	New Extensions				$ 45,000	
Grizzly Valley New Extension Out of Subdivision	Forced	New Extensions				$ 415,000	

List of Forced Projects 2008 to 2012

Project Name	Project Categoy	Appropriation Type	2008	2009	2010	2011	2012
Yukon Housing Abbeyfield Senior's Residence	Forced	New Extensions				$ 48,000	
Falcon Ridge Development Stage 4	Forced	New Extensions				$ 271,000	$ 34,000
Watson Lake Hospital Upgrade	Forced	New Extensions				$ 104,000	
Water Front Place Line Relocation	Forced	New Extensions				$ 385,000	$ 100,000
Northwestel Fox Point	Forced	New Extensions					$ 308,000
Northwestel Minto	Forced	New Extensions					$ 308,000
City of Whitehorse Ponderosa Communication Tower	Forced	New Extensions					$ 34,000
Lot 1084 Grizzly Valley	Forced	New Extensions				$ 37,000	
6-Plex 1204 Centennial	Forced	New Extensions				$ 44,000	
Ingram 6-Plex Subdivision	Forced	New Extensions				$ 165,000	
14th Ave Whitehorse	Forced	New Extensions				$ 34,000	
Condominium - 602 Main Street	Forced	New Extensions				$ 33,000	
F.H. Collins Secondary School Transformer	Forced	New Extensions				$ 72,000	$ 48,000
Carcross Retail Shops	Forced	New Extensions				$ 51,000	
Lot 1309 Ibex	Forced	New Extensions				$ 33,000	
8-Plex Lot 1127 Hillcrest	Forced	New Extensions				$ 35,000	
Yukon Government Water Treatment Plant	Forced	New Extensions				$ 34,000	
Grizzly Valley New Extension In Subdivision	Forced	New Extensions				$ 193,000	$ 272,000
Yukon Government Mt. Lorne Land Fill	Forced	New Extensions					$ 27,000
Yukon Government Tagish Landfill	Forced	New Extensions					$ 104,000
Kulan Area Line Improvements	Forced	New Extensions				$ 34,000	$ 41,000
Lot 1368 Mayo Road	Forced	New Extensions				$ 80,000	
Hidden Haven	Forced	New Extensions					$ 78,000
Lot 405 Takhini	Forced	New Extensions					$ 130,000
Mah's Point Condominiums	Forced	New Extensions					$ 193,000
City of Whitehorse Selkirk Street Pump House # 6	Forced	New Extensions					$ 58,000
Grey Wolf 1583 Wann Road	Forced	New Extensions					$ 198,000
Yukon Government Ross River Pole Relocation	Forced	New Extensions					$ 122,000
Lots 1095/1096 Grizzly Subdivision	Forced	New Extensions					$ 32,000
20 Laberge Road Service Upgrade	Forced	New Extensions					$ 26,000
City of Whitehorse Marwell Reroute	Forced	New Extensions					$ 28,000
Lot 1395 North Klondike Highway	Forced	New Extensions					$ 47,000
Lot 1014 Alaska Highway South	Forced	New Extensions					$ 39,000
Lot 1146 Crestview Development	Forced	New Extensions					$ 161,000
Ingram Subdivision 15 Units	Forced	New Extensions					$ 60,000
Betty's Haven Shelter Lot 6	Forced	New Extensions					$ 65,000
Yukon Government Civil Excavations in Watson Lake	Forced	New Extensions					$ 62,000
Yukon Government Teslin Pole Moves	Forced	New Extensions					$ 67,000
Carcross Tagish First Nation C82B Subdivision	Forced	New Extensions					$ 86,000
Lot 105 Otter Road	Forced	New Extensions					$ 35,000
Liard First Nation Lots 123 and 134 2 Mile Subdivision	Forced	New Extensions					$ 55,000
Daylu Dena 10 Lots Lower Post	Forced	New Extensions					$ 74,000
New Hangar Condor Road	Forced	New Extensions					$ 51,000
Other 2008	Forced	New Extensions	$ 79,000				
Other 2009	Forced	New Extensions		$ 100,000			
Other 2010	Forced	New Extensions			$ 122,000		
Other 2011	Forced	New Extensions				$ 366,000	
Other 2012	Forced	New Extensions					$ 95,000
Hamilton Boulevard Extension	Forced	Street and Sentinel Lighting	$ 435,000	$ 41,000			
Whitehorse Copper Light Additions	Forced	Street and Sentinel Lighting	$ 131,000				
Foxhaven Street Lights Relocation	Forced	Street and Sentinel Lighting	$ 82,000				
Quartz Road Street Lights Relocation	Forced	Street and Sentinel Lighting	$ 21,000				
Ta'an Kwach'an Council Subdivision	Forced	Street and Sentinel Lighting		$ 54,000			
Yukon Government Ingram Subdivision Street Lights	Forced	Street and Sentinel Lighting		$ 113,000	$ 50,000		
Takhini North Subdivision	Forced	Street and Sentinel Lighting		$ 86,000	$ 56,000		
Whistle Bend Way Light Additions	Forced	Street and Sentinel Lighting			$ 62,000	$ 143,000	
Takhini River Lights	Forced	Street and Sentinel Lighting			$ 24,000		

List of Forced Projects 2008 to 2012

Project Name	Project Categoy	Appropriation Type	2008	2009	2010	2011	2012
Wharf Lighting 1st Ave Whitehorse	Forced	Street and Sentinel Lighting				$ 147,000	
Grizzly Valley Street Lights	Forced	Street and Sentinel Lighting				$ 27,000	$ 33,000
Whistle Bend Stage 1 & 2 Street Lights	Forced	Street and Sentinel Lighting				$ 257,000	$ 150,000
Trail Lighting along Whitehorse Waterfront to Shipyards Park	Forced	Street and Sentinel Lighting				$ 100,000	
Black Street Additions and Rebuild	Forced	Street and Sentinel Lighting				$ 20,000	
Boxwood Light Upgrade	Forced	Street and Sentinel Lighting				$ 44,000	
Black Street - 6th Avenue Escarpment	Forced	Street and Sentinel Lighting					$ 37,000
Yukon Government Lights on 8th Street Watson Lake	Forced	Street and Sentinel Lighting					$ 143,000

The Yukon Electrical Company Limited
An ATCO Company

MAINTENANCE WORK REQUEST

Originator Section

District File No. M69-2013 Date Requested: Feb 6th Plant/5L # 52628

Requested By: M Johnson Address: old alaska highway

Customer: SWMS # Breaker # 58686

Description of Work to be done:

First tap after scout bay road on same side of road
Change DG XMER pole
Change old XMER ; old green box

Repair Priority: **2** (1 to 2 years) **7** (30 days) **9** (immediate)

Description of Work Completed

Name: Date:

Description of Service

Structure Type: P140 P182 b10 X41B

Xmer Change 10 KVA to 10 KVA Brkr Change to

Voltage (PRI/SEC):

Poles Required: 1 4/0/4 (number/size/class) Primary Cndctrs: #4 2 (number/size/type)

Secondary Cndctrs: (number/size/type) Services: (number/size/type)

Manpower Req'd: Equipment Req'd:

Outage Req'd (Y/N) Y Switch/Device# S6555 AMPS Time

# of Cust. Affected 1

Access:

Landowner Concerns

Hazards in the Area

ATTACH A SKETCH AND PHOTCOPY OF MAP SECTION IF REQUIRED

District Approval Section

Date: Feb 15/13 Date Required by: Send to: Lulle Horrelt

Labour # Equipment # Material #

Approved by: Date Approved: Feb 13/13

IS THIS A SYSTEM IMPROVEMENT?

ATTACHMENTS (PLEASE CIRCLE) ACCOUNTS RECEIVABLE: YES / N/A

INVOICE: YES / N/A IF YES FROM: ? MATERIALS LIST: YES / N/A OTHER:

The Yukon Electrical Company Limited
Distribution Improvement Project Listing By Priority 2008-2015

Project Name	Priority	Appropriation Type	2008	2009	2010	2011	2012	2013	2014	2015
4L311 Upgrade Distribution Lines Between 1st and 6th Avenue Downtown Whitehorse	A	Distribution Improvements	$ 439,000							
Connect Pelly Crossing into Yukon Interconnected System	A	Distribution Improvements	$ 435,000							
Ketza Court Live Front Transformers Replacement	A	Distribution Improvements	$ 346,000							
5L628 Squanga Road Rebuild	A	Distribution Improvements	$ 290,000							
Right of Way Widening	A	Distribution Improvements	$ 268,000	$ 240,000	$ 304,000	$ 331,000	$ 377,000	$ 374,000	$ 389,000	$ 405,000
9L - Km 129 to Km 132 South Klondike Highway - Distribution Line Rebuild	A	Distribution Improvements	$ 189,000							
Hillcrest Subdivision Conversion	A	Distribution Improvements	$ 93,000	$ 152,000	$ 226,000	$ 2,000	$ 252,000	$ 275,000	$ 250,000	
System Upgrades Lot 1378/79 Range Road	A	Distribution Improvements	$ 93,000							
Miscellaneous Pole Replacements	A	Distribution Improvements	$ 92,000	$ 22,000	$ 26,000	$ 70,000	$ 60,000	$ 260,000	$ 260,000	$ 260,000
Cadet Camp Three Phase Service System Improvement	A	Distribution Improvements	$ 83,000							
9L Reliability Upgrade Squanga Lake Area	A	Distribution Improvements	$ 77,000	$ 51,000						
Test and Treat Pole Program	A	Distribution Improvements	$ 72,000		$ 57,000		$ 153,000	$ 110,000	$ 120,000	$ 130,000
Tagish Bridge Conduit Replacement	A	Distribution Improvements	$ 60,000							
Echo Lake Road Upgrade	A	Distribution Improvements	$ 52,000	$ 75,000						
McIntyre Subdivision 34.5kV Upgrade	A	Distribution Improvements	$ 47,000							
Morley Bay Line Upgrade	A	Distribution Improvements	$ 46,000							
Birch Alley Upgrade	A	Distribution Improvements	$ 45,000	$ 32,000						
Campbell Highway Relocation	A	Distribution Improvements	$ 43,000							
Carmacks Upper Bench Rerouting	A	Distribution Improvements	$ 31,000							
Paddlewheel Line Relocation	A	Distribution Improvements	$ 30,000							
Carmacks Planned Pole Replacements	A	Distribution Improvements	$ 28,000							
Porter Creek Regulator Upgrade	A	Distribution Improvements	$ 26,000							
Beaver Creek Planned Pole Replacements	A	Distribution Improvements	$ 25,000							
North Star Clearance Upgrade	A	Distribution Improvements	$ 24,000							
McDonald Road to Centennial Road Upgrade	A	Distribution Improvements	$ 23,000	$ 24,000						
McIntyre Creek Pumphouse Upgrade	A	Distribution Improvements	$ 23,000							
Arkell Subdivision Upgrade	A	Distribution Improvements	$ 21,000	$ 197,000						
Marwell Subdivision Improvements	A	Distribution Improvements	$ 21,000							
Wickstrom Road Line Relocation for Whitehorse General Hospital Residence and Medical Building	A	Distribution Improvements		$ 83,000						
Liard River Crossing	A	Distribution Improvements		$ 29,000						
System Upgrade on Hotsprings River Road	A	Distribution Improvements		$ 22,000						
Teslin and Klondike Road Upgrade	A	Distribution Improvements		$ 20,000	$ 30,000					
Watson Lake Hotel Upgrade	A	Distribution Improvements		$ 20,000						
Whistlebend 34.5kV Substation Distribution Lines	A	Distribution Improvements			$ 492,000	$ 156,000				
Takhini North Upgrade	A	Distribution Improvements			$ 134,000					
Watson Lake 3-Phase System Protection Upgrade	A	Distribution Improvements			$ 100,000					
Main Steel Alley 4th - 7th Avenue Upgrade	A	Distribution Improvements			$ 98,000					
Old Crow Pole Change Outs	A	Distribution Improvements			$ 46,000					
Main Street Alley Upgrade	A	Distribution Improvements			$ 44,000					
Nordenskiold River Bridge Rerouting	A	Distribution Improvements			$ 42,000					
Mount Sima Subdivision	A	Distribution Improvements			$ 42,000					
Destruction Bay Main Feeder	A	Distribution Improvements			$ 42,000					
North Klondike Grounding Improvements	A	Distribution Improvements			$ 42,000					
4L316 Two Mile Hill Conductor Upgrade	A	Distribution Improvements			$ 38,000					
Pole Removal Wickstrom Road	A	Distribution Improvements			$ 25,000					
McIntyre Subdivision Prebuilding Work	A	Distribution Improvements			$ 22,000					
Whistle Bend Substation	A	Distribution Improvements				$ 1,690,000	$ 423,000			
System Upgrade, Extension of 5L628 to Grizzly Valley	A	Distribution Improvements				$ 454,000				
5L626 Double Circuit Line to Whistle Bend Substation	A	Distribution Improvements				$ 200,000				
Hotsprings Road Upgrade	A	Distribution Improvements				$ 190,000				
Upgrade Laberge Substation Transformer to 10 MVA	A	Distribution Improvements				$ 189,000				
Whistle Bend Substation Transformer	A	Distribution Improvements				$ 127,000				
Line Upgrade and Relocation Army Beach	A	Distribution Improvements				$ 92,000				
Line Upgrade and Relocation Lot 56 Paint Mountain	A	Distribution Improvements				$ 69,000				
System Upgrade 113 Copper Road	A	Distribution Improvements				$ 53,000				
Line Relocation Eagle Way	A	Distribution Improvements				$ 30,000				
Carcross Town Pole Replacements	A	Distribution Improvements				$ 27,000				
Configure Pelly Substation to Yukon Interconnected System	A	Distribution Improvements				$ 23,000				
Centennial Street Upgrades	A	Distribution Improvements				$ 20,000				
5L628 Crestview to Mayo Road Corner Double Circuit	A	Distribution Improvements					$ 628,000			
Shipyard's Substation Transformer Failure and Upgrades	A	Distribution Improvements					$ 473,000			
Laberge Substation 34.5kV Conductor Upgrade	A	Distribution Improvements					$ 103,000			
Whitehorse Elementary School Transformer Upgrade	A	Distribution Improvements					$ 94,000			
97 Lewes Boulevard Transformer Upgrade	A	Distribution Improvements					$ 70,000			
Laberge Substation Upgrade	A	Distribution Improvements					$ 57,000			
Range Road Line Rerouting	A	Distribution Improvements					$ 56,000			
Ponderosa Road Vault Addition and Service Upgrade	A	Distribution Improvements					$ 35,000			
Whitehorse Service Area Line Clearance Upgrades	A	Distribution Improvements					$ 25,000			
Marsh Lake Structure Upgrade	A	Distribution Improvements					$ 21,000			
System Improvements Lowe Street	A	Distribution Improvements					$ 21,000			
McIntyre Subdivision Replacement Stage 1	A	Distribution Improvements						$ 475,000	$ 250,000	
Downtown Whitehorse 4L313 Labert Street to Elliot Street - Replace with Underground Lines	A	Distribution Improvements						$ 424,000		
Hotsprings Road Main Line Relocation and Upgrade	A	Distribution Improvements						$ 325,000		
Tagish 5L600 Rebuild	A	Distribution Improvements						$ 300,000		$ 276,000

The Yukon Electrical Company Limited
Distribution Improvement Project Listing By Priority 2008-2015

Project Name	Priority	Appropriation Type	2008	2009	2010	2011	2012	2013	2014	2015
Crestview to Mayo Road 5L628 Upgrade to 266 MCM	A	Distribution Improvements						$ 250,000		
Old Alaska Highway Bypass	A	Distribution Improvements						$ 248,000		
Jack Hulland School Upgrades	A	Distribution Improvements						$ 100,000		
Carmacks North Main Line Rebuild	A	Distribution Improvements						$ 100,000		
Whitehorse Area Line Clearance Upgrades	A	Distribution Improvements						$ 65,000	$ 70,000	
Teslin Area Pole Upgrades	A	Distribution Improvements						$ 53,000		
Teslin Sawmill Road Upgrade for New Subdivision	A	Distribution Improvements						$ 38,000		
Lot 1037 Range Road Line Upgrade	A	Distribution Improvements						$ 34,000		
Whitehorse Safety Code Corrections	A	Distribution Improvements						$ 30,000		
Whitehorse 5L628 and New 34.5kV Build	A	Distribution Improvements							$ 1,890,000	
Downtown Whitehorse 25kV Conversion	A	Distribution Improvements							$ 450,000	$ 450,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	A	Distribution Improvements							$ 250,000	$ 350,000
Marwell Lot 14 Transformer Upgrade	A	Distribution Improvements							$ 100,000	
Riverdale Lewes Substation 25kV Transformer	A	Distribution Improvements							$ 100,000	
Whitehorse Hotsprings Road 3 Phase Conversion	A	Distribution Improvements								$ 363,000
MacDonald Road Pole Change	A	Distribution Improvements								$ 250,000
Riverdale Line 4L317 Tagish Road	A	Distribution Improvements								$ 250,000
Watson Lake Underground Subdivision Replacement	A	Distribution Improvements								$ 100,000
Grey Mountain 4L320 Tie Upgrade	A	Distribution Improvements								$ 65,000
Upgrade of S2278	A	Distribution Improvements								$ 45,000
Pelly Crescent to Grey Mountain H Frames	A	Distribution Improvements								
Carcross Relocate 34 kV Stage 2	A	Distribution Improvements								
Carmacks One Phase Line by Heli Pad on Highway	A	Distribution Improvements								
Tagish Section to Taku 2.5 km	A	Distribution Improvements								
Lambert Street - DQ Alley	A	Distribution Improvements								
Little Atlin Lake Area 3 Phase Pole Upgrades	B	Distribution Improvements	$ 60,000							
Convert Spirit Lake to 14.4kV	B	Distribution Improvements	$ 22,000							
Robinson Substation Upgrade	B	Distribution Improvements		$ 39,000						
Whitehorse Airport Conversion	B	Distribution Improvements		$ 29,000						
Porter Creek Breaker Replacement	B	Distribution Improvements			$ 54,000					
Destruction Bay Distribution Breaker Addition	B	Distribution Improvements			$ 54,000					
Haines Junction Distribution Breaker Addition	B	Distribution Improvements			$ 51,000					
System Frequency Upgrades at S150 Substation	B	Distribution Improvements			$ 39,000	$ 37,000				
Whitehorse Copper Rebuild	B	Distribution Improvements			$ 27,000					
Laberge Substation Distribution Upgrades	B	Distribution Improvements				$ 416,000				
PCB Identification and Transformer Change Outs	B	Distribution Improvements				$ 239,000	$ 401,000	$ 175,000	$ 100,000	$ 100,000
Regulator to North Klondike Highway	B	Distribution Improvements					$ 154,000			
Breaker Replacement in Services Substation	B	Distribution Improvements					$ 84,000			
Old Crow 3rd Distribution Breaker	B	Distribution Improvements					$ 78,000			
Marsh Lake Substation Upgrade	B	Distribution Improvements					$ 45,000			
CRE Breaker Replacement in Lewes Boulevard	B	Distribution Improvements					$ 30,000			
Ross River Recloser for S7580	B	Distribution Improvements					$ 30,000			
Porter Creek Underground Vaults Replacement	B	Distribution Improvements					$ 28,000			
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	B	Distribution Improvements						$ 250,000	$ 300,000	
Pelly Crossing Substation Fence	B	Distribution Improvements						$ 100,000		
Whitehorse Asset Management - Create a New Pole Database	B	Distribution Improvements						$ 75,000	$ 75,000	
Takhini/Marwell Completion of Mountain Air Subdivision	B	Distribution Improvements								$ 300,000
Lewes Lake Substation Conversion	B	Distribution Improvements								$ 146,000
Whitehorse Airport Hanger D Area Rebuild	B	Distribution Improvements								$ 140,000
Upper Liard - Replace Liard River Crossing	B	Distribution Improvements								$ 100,000
McLintock Substation Upgrade	B	Distribution Improvements								$ 90,000
Spirit Lake Substation Upgrade	B	Distribution Improvements								$ 88,000
Deep Creek Subdivision Connection to Whitehorse Distribution	B	Distribution Improvements								$ 60,000
Stewart Crossing West Town Conversion	B	Distribution Improvements								$ 60,000

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List of Unplanned Outages from 2008-2012

Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2008-01-01	14:48	591 Upper Liard	BRR00004	Defective Equipment	104	0.70
2008-01-01	14:48	590 Lower Post	BRR00003	Defective Equipment	88	0.70
2008-01-01	13:00	571 Whitehorse	RSM00041	Adverse Weather	20	1.25
2008-01-01	16:45	574 Carcross	RSM00043	Adverse Weather	2	3.25
2008-01-01	14:30	571 Whitehorse	RSM00042	Adverse Weather	3	4.80
2008-01-01	13:00	571 Whitehorse	THB00079	Adverse Weather	10	1.00
2008-01-01	17:00	571 Whitehorse	THB00080	Adverse Weather	3	0.35
2008-01-02	8:00	571 Whitehorse	SS000105	Adverse Weather	1	0.60
2008-01-02	7:30	571 Whitehorse	AMI00021	Adverse Weather	1	8.15
2008-01-03	12:10	576 Teslin	DRR00135	Adverse Weather	325	0.30
2008-01-05	18:45	571 Whitehorse	RTW00097	Adverse Weather	4	2.15
2008-01-05	18:45	585 Tagish	RTW00098	Adverse Weather	1	3.25
2008-01-05	18:45	571 Whitehorse	RTW00096	Adverse Weather	1	1.00
2008-01-05	18:30	582 Ross River	SS000106	Adverse Weather	2	17.50
2008-01-05	16:30	571 Whitehorse	RTW00095	Adverse Weather	2	0.85
2008-01-05	22:00	585 Tagish	RTW00099	Adverse Weather	1	0.55
2008-01-06	10:00	571 Whitehorse	RTW00100	Adverse Weather	1	1.01
2008-01-07	0:01	577 Destruction Bay	TGG00118	Adverse Weather	2	15.80
2008-01-07	12:48	581 Stewart Crossing	RAF00009	Loss of Supply - Yukon Energy	31	0.10
2008-01-07	7:25	577 Destruction Bay	RAF00008	Unknown/Other	135	0.04
2008-01-07	6:23	577 Destruction Bay	RAF00007	Unknown/Other	135	0.04
2008-01-07	13:20	571 Whitehorse	SS000108	Defective Equipment	1	3.65
2008-01-07	12:08	571 Whitehorse	BSP00097	Adverse Weather	9	0.65
2008-01-08	15:25	571 Whitehorse	AMI00031	Adverse Weather	3	0.08
2008-01-08	13:05	571 Whitehorse	AMI00030	Foreign Interference	6	0.35
2008-01-08	15:00	571 Whitehorse	AMI00032	Adverse Weather	2	2.40
2008-01-09	13:45	571 Whitehorse	RSM00045	Adverse Weather	1	0.50
2008-01-09	14:00	585 Tagish	BSP00098	Adverse Weather	2	0.60
2008-01-09	14:50	585 Tagish	BSP00099	Adverse Weather	3	0.60
2008-01-09	4:00	576 Teslin	RSM00044	Adverse Weather	1	7.60
2008-01-10	12:10	571 Whitehorse	AMI00033	Trees	4	0.60
2008-01-11	15:00	576 Teslin	BSP00100	Trees	320	0.90
2008-01-12	19:00	571 Whitehorse	DRR00138	Adverse Weather	12	1.63
2008-01-12	15:30	585 Tagish	BSP00103	Adverse Weather	14	0.86
2008-01-12	15:30	571 Whitehorse	BSP00102	Adverse Weather	10	0.08
2008-01-12	14:45	571 Whitehorse	BSP00101	Adverse Weather	1	0.75
2008-01-12	16:30	571 Whitehorse	SS000109	Adverse Weather	1	1.65
2008-01-12	16:30	571 Whitehorse	AMI00034	Adverse Weather	3	2.50
2008-01-12	17:00	571 Whitehorse	DRR00137	Adverse Weather	1	1.40
2008-01-12	15:30	571 Whitehorse	AMI00039	Adverse Weather	5	1.00
2008-01-12	19:30	571 Whitehorse	BSP00104	Adverse Weather	2	0.80
2008-01-12	20:30	571 Whitehorse	BSP00105	Adverse Weather	1	0.50
2008-01-12	22:05	571 Whitehorse	BSP00107	Adverse Weather	3	0.50
2008-01-12	15:30	571 Whitehorse	AMI00038	Adverse Weather	3	1.75
2008-01-13	2:45	571 Whitehorse	AMI00035	Adverse Weather	25	1.50
2008-01-13	4:30	592 Marsh Lake	AMI00036	Adverse Weather	3	0.80
2008-01-13	7:00	571 Whitehorse	BSP00108	Adverse Weather	18	0.50
2008-01-13	3:30	576 Teslin	AMI00037	Trees	320	5.40
2008-01-14	12:05	590 Lower Post	WTT00231	Foreign Interference	88	1.35
2008-01-16	14:30	592 Marsh Lake	BSP00109	Adverse Weather	7	0.75
2008-01-17	13:56	580 Keno City	DRR00141	Loss of Supply - Yukon Energy	52	0.01
2008-01-17	12:00	571 Whitehorse	RJZ00123	Trees	1	6.25
2008-01-22	12:12	579 Old Crow	NC000006	Unknown/Other	179	0.01
2008-01-22	21:35	571 Whitehorse	BSP00106	Adverse Weather	1	0.65
2008-01-26	10:11	573 Watson Lake	JES00051	Loss of Supply - Yukon Electrical	820	0.20
2008-01-26	10:11	590 Lower Post	JES00050	Loss of Supply - Yukon Electrical	89	0.20
2008-01-26	10:11	591 Upper Liard	JES00052	Loss of Supply - Yukon Electrical	109	0.20
2008-01-30	12:00	585 Tagish	RJZ00124	Adverse Environment	3	3.25
2008-02-01	0:00	571 Whitehorse	SS000114	Defective Equipment	1	2.50
2008-02-02	16:45	571 Whitehorse	SS000116	Defective Equipment	85	0.80
2008-02-02	19:15	571 Whitehorse	SS000115	Defective Equipment	5	2.00
2008-02-10	18:50	571 Whitehorse	RJZ00125	Defective Equipment	1	0.65
2008-02-12	16:10	573 Watson Lake	WTT00232	Foreign Interference	2	0.15
2008-02-13	15:15	591 Upper Liard	BRR00007	Trees	1	0.55

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2008-02-13	7:10	573 Watson Lake	BRR00006	Adverse Weather	3	0.25
2008-02-14	6:45	571 Whitehorse	DRR00142	Defective Equipment	1	1.15
2008-02-16	15:20	575 Carmacks	DRR00143	Defective Equipment	1	2.65
2008-02-18	11:00	572 Haines Junction	TGG00120	Unknown/Other	1	2.50
2008-02-19	18:30	576 Teslin	SS000118	Trees	1	1.00
2008-02-20	10:30	573 Watson Lake	WTT00233	Foreign Interference	1	0.30
2008-02-21	14:50	592 Marsh Lake	SS000119	Trees	25	0.15
2008-02-23	18:25	571 Whitehorse	THB00077	Foreign Interference	1	0.60
2008-02-23	12:20	571 Whitehorse	THB00076	Foreign Interference	5	0.50
2008-02-23	11:53	571 Whitehorse	AMI00040	Unknown/Other	1	4.55
2008-03-03	3:41	579 Old Crow	PTM00062	Loss of Supply - Yukon Electrical	181	0.85
2008-03-04	16:05	572 Haines Junction	TGG00121	Defective Equipment	2	2.00
2008-03-04	9:30	576 Teslin	RSM00046	Foreign Interference	1	2.75
2008-03-11	11:10	583 Pelly Crossing	RSM00047	Foreign Interference	1	5.35
2008-03-12	15:45	571 Whitehorse	RJZ00129	Foreign Interference	1	0.75
2008-03-14	16:20	571 Whitehorse	RSM00048	Defective Equipment	2	3.25
2008-03-21	17:30	571 Whitehorse	RJZ00130	Defective Equipment	2	0.80
2008-03-26	7:35	571 Whitehorse	RJZ00131	Adverse Environment	3	-
2008-03-27	11:45	573 Watson Lake	BRR00009	Defective Equipment	1	0.75
2008-03-29	12:00	580 Keno City	THB00085	Foreign Interference	1	3.50
2008-03-30	9:00	580 Keno City	THB00086	Foreign Interference	3	6.00
2008-03-31	18:50	574 Carcross	RJZ00132	Defective Equipment	2	1.55
2008-04-03	8:21	573 Watson Lake	JES00055	Loss of Supply - Yukon Electrical	547	0.04
2008-04-03	8:21	591 Upper Liard	JES00053	Loss of Supply - Yukon Electrical	73	0.02
2008-04-03	8:21	590 Lower Post	JES00054	Loss of Supply - Yukon Electrical	87	0.04
2008-04-12	19:07	590 Lower Post	WTT00235	Defective Equipment	1	0.78
2008-04-12	10:20	573 Watson Lake	WTT00234	Foreign Interference	6	0.25
2008-04-12	12:05	571 Whitehorse	RTW00103	Foreign Interference	8	1.35
2008-04-14	21:00	592 Marsh Lake	RSM00049	Foreign Interference	20	1.20
2008-04-19	16:50	572 Haines Junction	RJZ00134	Foreign Interference	1	1.78
2008-04-21	9:37	585 Tagish	RTW00105	Foreign Interference	2	1.50
2008-04-22	10:00	573 Watson Lake	WTT00326	Defective Equipment	1	0.40
2008-04-25	12:30	573 Watson Lake	BRR00010	Foreign Interference	2	1.00
2008-04-27	8:45	592 Marsh Lake	AMI00042	Adverse Weather	1	2.50
2008-04-27	14:45	571 Whitehorse	DRR00145	Foreign Interference	12	0.45
2008-04-29	11:30	585 Tagish	TGG00124	Unknown/Other	6	2.00
2008-04-30	10:26	578 Beaver Creek	PTM00064	Loss of Supply - Yukon Electrical	120	5.90
2008-04-30	12:55	571 Whitehorse	SS000123	Adverse Environment	1	5.60
2008-05-01	6:30	571 Whitehorse	AMI00043	Unknown/Other	2	4.00
2008-05-01	17:06	578 Beaver Creek	PTM00065	Loss of Supply - Yukon Electrical	121	0.30
2008-05-04	22:50	571 Whitehorse	BSP00130	Loss of Supply - Yukon Energy	864	3.25
2008-05-04	22:50	571 Whitehorse	BSP00133	Loss of Supply - Yukon Energy	969	3.34
2008-05-04	22:50	575 Carmacks	BSP00135	Loss of Supply - Yukon Energy	280	0.08
2008-05-04	22:50	571 Whitehorse	BSP00134	Loss of Supply - Yukon Energy	2,686	3.17
2008-05-04	23:49	572 Haines Junction	BSP00138	Loss of Supply - Yukon Energy	490	0.01
2008-05-04	22:50	576 Teslin	BSP00137	Loss of Supply - Yukon Energy	300	0.06
2008-05-04	22:50	582 Ross River	BSP00136	Loss of Supply - Yukon Energy	220	0.04
2008-05-04	22:50	571 Whitehorse	BSP00131	Loss of Supply - Yukon Energy	1,922	3.80
2008-05-04	22:50	571 Whitehorse	BSP00129	Loss of Supply - Yukon Energy	870	2.29
2008-05-04	22:50	594 Deep Creek	BSP00131D	Loss of Supply - Yukon Energy	41	1.90
2008-05-04	22:50	571 Whitehorse	BSP00128	Loss of Supply - Yukon Energy	1,929	1.66
2008-05-04	22:50	585 Tagish	BSP00131C	Loss of Supply - Yukon Energy	371	3.26
2008-05-04	22:50	571 Whitehorse	BSP00132	Loss of Supply - Yukon Energy	1,597	3.00
2008-05-04	22:50	574 Carcross	BSP00131B	Loss of Supply - Yukon Energy	303	3.26
2008-05-04	22:50	592 Marsh Lake	BSP00131A	Loss of Supply - Yukon Energy	447	3.22
2008-05-06	10:30	571 Whitehorse	RJZ00139	Defective Equipment	981	0.67
2008-05-06	10:30	571 Whitehorse	RJZ00137	Defective Equipment	2,168	0.28
2008-05-06	10:30	571 Whitehorse	RJZ00138	Defective Equipment	840	0.49
2008-05-07	8:20	583 Pelly Crossing	NC000007	Loss of Supply - Yukon Electrical	168	0.04
2008-05-08	11:35	583 Pelly Crossing	NC000008	Loss of Supply - Yukon Electrical	168	0.04
2008-05-11	11:12	583 Pelly Crossing	NC000009	Defective Equipment	260	0.24
2008-05-14	18:40	571 Whitehorse	RJZ00141	Trees	1	15.35
2008-05-15	10:45	571 Whitehorse	RJZ00145	Trees	6	2.25
2008-05-15	16:00	571 Whitehorse	RJZ00147	Trees	2	2.50

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2008-05-15	15:35	571 Whitehorse	RJZ00146	Trees	10	0.80
2008-05-15	15:00	591 Upper Liard	WTT00330	Trees	1	6.35
2008-05-15	16:00	576 Teslin	RSM00052	Trees	1	2.00
2008-05-15	14:00	573 Watson Lake	BRR00011A	Trees	7	2.50
2008-05-15	14:00	576 Teslin	RSM00051	Trees	1	2.75
2008-05-15	19:45	592 Marsh Lake	RTW00107	Trees	334	1.00
2008-05-15	11:50	591 Upper Liard	WTT00329	Trees	2	7.40
2008-05-15	9:45	585 Tagish	RTW00106	Trees	579	6.69
2008-05-15	10:00	571 Whitehorse	RJZ00144	Trees	1	0.65
2008-05-15	9:15	592 Marsh Lake	RSM00054	Trees	1	2.00
2008-05-15	9:15	592 Marsh Lake	RSM00050	Trees	40	4.65
2008-05-15	9:00	571 Whitehorse	RJZ00143	Trees	3	1.00
2008-05-15	11:45	591 Upper Liard	WTT00328	Trees	7	5.30
2008-05-15	11:45	591 Upper Liard	WTT00327	Trees	111	1.04
2008-05-16	18:16	571 Whitehorse	RNK00276	Loss of Supply - Yukon Energy	2,168	0.48
2008-05-16	18:16	571 Whitehorse	RNK00275	Loss of Supply - Yukon Energy	1,929	0.32
2008-05-17	23:57	591 Upper Liard	JES00057	Loss of Supply - Yukon Electrical	126	0.20
2008-05-17	23:57	590 Lower Post	JES00058	Loss of Supply - Yukon Electrical	93	0.20
2008-05-17	23:57	573 Watson Lake	JES00056	Loss of Supply - Yukon Electrical	739	0.07
2008-05-19	21:00	571 Whitehorse	RSM00055	Trees	1,015	1.16
2008-05-21	18:09	571 Whitehorse	THB00079A	Loss of Supply - Yukon Energy	2,168	0.35
2008-05-24	8:00	573 Watson Lake	WTT00331	Foreign Interference	5	0.20
2008-05-24	12:00	571 Whitehorse	THB00084A	Foreign Interference	1	2.50
2008-05-26	9:00	571 Whitehorse	RSM00057	Unknown/Other	8	1.25
2008-05-27	17:00	571 Whitehorse	RSM00058	Foreign Interference	1	3.50
2008-05-28	20:54	583 Pelly Crossing	PTM00066	Loss of Supply - Yukon Electrical	168	0.04
2008-05-28	7:20	572 Haines Junction	TGG00126	Foreign Interference	1	1.65
2008-05-30	17:50	590 Lower Post	BRR00012	Trees	88	1.15
2008-05-30	19:00	573 Watson Lake	BRR00013	Trees	1	2.00
2008-06-05	16:20	571 Whitehorse	BAC00001	Human Element	5	1.90
2008-06-08	9:00	576 Teslin	RSM00060	Trees	25	5.25
2008-06-08	8:30	576 Teslin	RSM00059	Trees	16	4.00
2008-06-08	12:00	571 Whitehorse	SS000128	Adverse Weather	8	1.50
2008-06-09	17:00	571 Whitehorse	RSM00063	Defective Equipment	2	2.00
2008-06-09	14:00	571 Whitehorse	RSM00062	Unknown/Other	2	2.55
2008-06-09	7:00	572 Haines Junction	SS000129	Adverse Weather	8	2.65
2008-06-10	11:55	571 Whitehorse	DRR00146	Foreign Interference	8	0.50
2008-06-10	4:30	571 Whitehorse	RSM00064	Defective Equipment	2	1.62
2008-06-12	8:15	573 Watson Lake	BRR00015	Foreign Interference	1	0.25
2008-06-13	15:45	571 Whitehorse	RSM00065	Defective Equipment	8	1.60
2008-06-14	9:27	573 Watson Lake	BRR00017	Foreign Interference	1	0.35
2008-06-14	21:40	571 Whitehorse	RJZ00149	Foreign Interference	1	0.50
2008-06-16	16:30	576 Teslin	SS000131	Trees	1	4.75
2008-06-17	13:00	571 Whitehorse	BAC00003	Foreign Interference	5	2.35
2008-06-17	10:20	571 Whitehorse	BAC00002	Adverse Weather	6	0.80
2008-06-19	8:00	571 Whitehorse	BAC00004	Lightning	1	0.60
2008-06-19	13:00	571 Whitehorse	BAC00005	Foreign Interference	2	0.75
2008-06-20	23:00	582 Ross River	SS000132	Trees	2	19.25
2008-06-21	5:00	590 Lower Post	THB00094	Adverse Environment	1	0.50
2008-06-21	9:20	571 Whitehorse	DRR00158	Unknown/Other	594	1.12
2008-06-21	10:50	571 Whitehorse	DRR00159	Foreign Interference	1	0.50
2008-06-22	3:30	573 Watson Lake	THB00095A	Trees	5	1.01
2008-06-22	6:00	571 Whitehorse	DRR00160	Unknown/Other	600	0.65
2008-06-22	20:20	572 Haines Junction	TGG00128	Defective Equipment	1	10.04
2008-06-23	20:25	575 Carmacks	RJZ00149A	Foreign Interference	1	2.35
2008-06-24	23:15	571 Whitehorse	RJZ00150	Adverse Environment	1	2.08
2008-06-24	5:55	573 Watson Lake	JES00059	Defective Equipment	115	0.15
2008-06-24	5:55	591 Upper Liard	JES00060	Defective Equipment	126	0.15
2008-06-24	11:59	575 Carmacks	RTW00125	Foreign Interference	1	1.15
2008-06-25	21:00	571 Whitehorse	MS000001	Defective Equipment	71	5.00
2008-06-26	8:30	592 Marsh Lake	BAC00006	Foreign Interference	1	2.00
2008-06-26	11:15	571 Whitehorse	BAC00007	Foreign Interference	1	1.75
2008-06-27	11:00	574 Carcross	SS000133	Trees	1	1.50
2008-06-28	16:30	571 Whitehorse	RTW00122	Trees	585	1.15

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2008-06-28	18:00	585 Tagish	MSO00003	Trees	48	2.24
2008-06-29	13:30	571 Whitehorse	RTW00124	Trees	1	11.00
2008-06-29	23:00	585 Tagish	BAC00008	Foreign Interference	2	2.50
2008-06-29	11:00	571 Whitehorse	MSO00002	Foreign Interference	1	1.50
2008-06-30	9:30	573 Watson Lake	BRR00019	Trees	1	1.65
2008-06-30	11:50	571 Whitehorse	MSO00004	Defective Equipment	2	23.92
2008-06-30	8:30	573 Watson Lake	BRR00018	Trees	6	0.65
2008-07-01	8:30	571 Whitehorse	RTW00126	Foreign Interference	6	2.35
2008-07-01	12:00	576 Teslin	MSO00005	Foreign Interference	1	3.80
2008-07-01	18:00	580 Keno City	RTW00125A	Loss of Supply - Yukon Energy	54	5.30
2008-07-02	18:00	585 Tagish	SS000137	Defective Equipment	2	6.75
2008-07-02	22:31	573 Watson Lake	JES00063	Defective Equipment	245	0.25
2008-07-02	22:31	590 Lower Post	JES00062	Defective Equipment	93	0.25
2008-07-02	17:00	585 Tagish	SS000136	Trees	3	3.00
2008-07-02	22:31	591 Upper Liard	JES00061	Defective Equipment	126	0.25
2008-07-02	7:05	580 Keno City	RTW00125B	Loss of Supply - Yukon Energy	54	0.08
2008-07-06	2:45	580 Keno City	THB00100	Loss of Supply - Yukon Energy	15	2.60
2008-07-07	11:00	571 Whitehorse	RJZ00151	Foreign Interference	5	1.00
2008-07-09	18:15	571 Whitehorse	THB00101	Defective Equipment	97	2.50
2008-07-09	10:00	577 Destruction Bay	TGG00129	Defective Equipment	1	2.50
2008-07-09	15:45	571 Whitehorse	RTW00128	Defective Equipment	210	1.35
2008-07-10	10:41	573 Watson Lake	BRR00020	Foreign Interference	2	1.03
2008-07-11	13:30	571 Whitehorse	RJZ00154	Foreign Interference	7	0.50
2008-07-11	8:15	571 Whitehorse	RJZ00152	Foreign Interference	1	0.50
2008-07-12	11:00	571 Whitehorse	DRR00162	Foreign Interference	8	0.65
2008-07-12	18:20	591 Upper Liard	BRR00021	Foreign Interference	1	0.60
2008-07-13	7:30	571 Whitehorse	DRR00163	Foreign Interference	16	1.10
2008-07-13	18:45	572 Haines Junction	RJZ00155	Defective Equipment	10	3.08
2008-07-13	16:05	590 Lower Post	BRR00022	Trees	99	3.08
2008-07-14	8:20	573 Watson Lake	BRR00023	Foreign Interference	1	0.80
2008-07-15	1:04	582 Ross River	PTM00067	Loss of Supply - Yukon Energy	219	0.04
2008-07-15	7:29	573 Watson Lake	BRR00025	Foreign Interference	2	0.70
2008-07-16	12:00	591 Upper Liard	BRR00026	Trees	9	0.80
2008-07-19	16:00	585 Tagish	BSP00139A	Trees	300	0.90
2008-07-19	13:25	573 Watson Lake	WTT00334	Foreign Interference	2	0.25
2008-07-19	17:30	594 Deep Creek	MSO00006	Lightning	41	0.90
2008-07-19	16:20	571 Whitehorse	AMI00045	Trees	812	0.10
2008-07-19	16:20	576 Teslin	AMI00046	Trees	324	0.09
2008-07-19	16:00	574 Carcross	BSP00139	Trees	300	0.90
2008-07-19	16:20	592 Marsh Lake	AMI00046A	Trees	444	0.10
2008-07-20	1:25	571 Whitehorse	BSP00140	Defective Equipment	1	0.60
2008-07-20	10:30	571 Whitehorse	AMI00044	Foreign Interference	1	1.00
2008-07-21	17:45	571 Whitehorse	AMI00047	Trees	1	1.40
2008-07-21	11:00	571 Whitehorse	BAC00009	Foreign Interference	4	0.90
2008-07-23	12:30	591 Upper Liard	WTT00335	Foreign Interference	1	0.60
2008-07-24	19:30	571 Whitehorse	SS000139	Foreign Interference	1	0.50
2008-07-24	10:40	572 Haines Junction	TGG00130x	Foreign Interference	7	2.08
2008-07-26	13:00	576 Teslin	MSO00009	Defective Equipment	1	3.75
2008-07-26	14:30	571 Whitehorse	SS000141	Trees	3	0.75
2008-07-26	19:49	571 Whitehorse	SS000143	Unknown/Other	850	0.65
2008-07-27	11:10	571 Whitehorse	MSO00010	Trees	1	1.08
2008-07-30	12:10	572 Haines Junction	DRR00164	Loss of Supply - Yukon Energy	490	1.33
2008-08-01	8:00	576 Teslin	RJZ00156	Foreign Interference	1	2.35
2008-08-02	13:00	571 Whitehorse	RJZ00157	Foreign Interference	1	0.85
2008-08-03	8:18	572 Haines Junction	TGG00133	Loss of Supply - Yukon Energy	25	5.26
2008-08-04	21:05	571 Whitehorse	RJZ00162	Loss of Supply - Yukon Energy	1,186	0.60
2008-08-04	21:05	592 Marsh Lake	RJZ00161	Loss of Supply - Yukon Energy	444	0.60
2008-08-04	21:05	574 Carcross	RJZ00160	Loss of Supply - Yukon Energy	296	0.60
2008-08-04	21:05	576 Teslin	RJZ00158	Loss of Supply - Yukon Energy	334	0.18
2008-08-04	21:05	585 Tagish	RJZ00159	Loss of Supply - Yukon Energy	359	0.60
2008-08-05	8:00	571 Whitehorse	RSM00067	Foreign Interference	1	1.00
2008-08-05	13:40	571 Whitehorse	RSM00068	Unknown/Other	14	0.65
2008-08-06	6:30	573 Watson Lake	BRR00027	Foreign Interference	2	12.60
2008-08-06	7:30	582 Ross River	AMI00049	Foreign Interference	5	4.75

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2008-08-06	3:40	571 Whitehorse	THB00105	Trees	3	2.65
2008-08-07	9:10	571 Whitehorse	RSM00069	Foreign Interference	1	0.50
2008-08-09	10:05	573 Watson Lake	WTT00336	Foreign Interference	1	0.60
2008-08-10	16:25	573 Watson Lake	WTT00337	Foreign Interference	99	4.80
2008-08-10	16:25	590 Lower Post	WTT00338	Foreign Interference	98	4.80
2008-08-12	10:00	571 Whitehorse	RSM00070	Defective Equipment	1	2.40
2008-08-13	15:20	571 Whitehorse	MSO00012	Foreign Interference	1	0.15
2008-08-13	11:27	573 Watson Lake	BRR00029	Foreign Interference	3	0.35
2008-08-14	15:00	573 Watson Lake	BRR00031	Foreign Interference	1	0.35
2008-08-15	22:30	573 Watson Lake	BRR00032	Unknown/Other	3	1.03
2008-08-16	9:30	573 Watson Lake	BRR00033	Unknown/Other	3	0.80
2008-08-16	22:00	573 Watson Lake	BRR00034	Defective Equipment	7	2.40
2008-08-17	16:40	571 Whitehorse	SS000147	Foreign Interference	1	3.00
2008-08-20	10:56	590 Lower Post	BRR00035	Loss of Supply - Yukon Electrical	93	0.15
2008-08-20	8:15	571 Whitehorse	BAC00012	Unknown/Other	1	1.08
2008-08-20	10:56	573 Watson Lake	BRR00037	Loss of Supply - Yukon Electrical	494	0.15
2008-08-20	10:56	591 Upper Liard	BRR00036	Loss of Supply - Yukon Electrical	135	0.15
2008-08-21	20:30	571 Whitehorse	RTW00130	Foreign Interference	3	1.15
2008-08-21	7:40	571 Whitehorse	MSO00013	Foreign Interference	5	0.60
2008-08-22	11:30	590 Lower Post	BRR00038	Trees	15	1.03
2008-08-25	10:00	572 Haines Junction	TGG00131	Foreign Interference	1	0.35
2008-08-25	10:47	571 Whitehorse	SS000148	Loss of Supply - Yukon Energy	3,341	0.53
2008-08-25	17:10	577 Destruction Bay	TGG00132	Foreign Interference	1	1.35
2008-08-27	10:00	590 Lower Post	WTT00343	Foreign Interference	87	0.75
2008-08-27	13:00	571 Whitehorse	RSM00071	Unknown/Other	1	0.85
2008-08-27	10:50	571 Whitehorse	SS000151	Foreign Interference	2	0.50
2008-08-28	14:00	582 Ross River	BAC00015	Foreign Interference	1	3.25
2008-08-28	16:45	571 Whitehorse	RJZ00163	Foreign Interference	10	0.50
2008-08-28	9:00	572 Haines Junction	SS000153	Loss of Supply - Yukon Energy	490	0.35
2008-08-28	15:00	571 Whitehorse	MSO00014	Foreign Interference	1	1.60
2008-08-29	12:20	571 Whitehorse	SS000153A	Loss of Supply - Yukon Energy	380	0.40
2008-08-29	19:00	592 Marsh Lake	MSO00016	Trees	4	3.80
2008-08-29	18:00	571 Whitehorse	MSO00015	Foreign Interference	12	1.03
2008-08-29	19:30	575 Carmacks	BAC00016	Foreign Interference	1	2.00
2008-08-30	9:30	572 Haines Junction	MSO00017	Foreign Interference	5	2.40
2008-08-30	8:38	571 Whitehorse	AMI00050	Unknown/Other	1	0.80
2008-08-31	11:00	571 Whitehorse	MSO00019	Trees	3	0.75
2008-09-02	14:40	573 Watson Lake	WTT00344	Foreign Interference	2	0.15
2008-09-02	10:00	576 Teslin	RSM00072	Foreign Interference	6	3.00
2008-09-02	20:06	572 Haines Junction	PTM00068	Loss of Supply - Yukon Energy	490	0.04
2008-09-03	16:05	571 Whitehorse	SS000154	Defective Equipment	2	0.40
2008-09-04	14:30	582 Ross River	BAC00017	Defective Equipment	7	6.00
2008-09-05	10:00	571 Whitehorse	BAC00018	Foreign Interference	4	1.25
2008-09-08	7:00	571 Whitehorse	AMI00051	Adverse Environment	2	5.00
2008-09-10	14:00	571 Whitehorse	RSM00073	Defective Equipment	350	2.00
2008-09-10	19:40	573 Watson Lake	RPL00016	Loss of Supply - Yukon Electrical	135	0.55
2008-09-10	12:50	571 Whitehorse	RJZ00165	Foreign Interference	1	0.65
2008-09-10	15:00	571 Whitehorse	RSM00073A	Defective Equipment	634	0.10
2008-09-10	7:15	573 Watson Lake	RPL00015	Loss of Supply - Yukon Electrical	135	0.50
2008-09-11	2:23	573 Watson Lake	RPL00017	Loss of Supply - Yukon Electrical	712	0.50
2008-09-11	9:10	571 Whitehorse	BAC00019	Foreign Interference	1	0.40
2008-09-11	2:23	590 Lower Post	RPL00019	Loss of Supply - Yukon Electrical	93	0.50
2008-09-11	2:23	591 Upper Liard	RPL00018	Loss of Supply - Yukon Electrical	135	0.50
2008-09-12	7:45	571 Whitehorse	RJZ00166	Foreign Interference	2	0.55
2008-09-19	8:30	571 Whitehorse	RJZ00167	Foreign Interference	6	1.00
2008-09-19	10:20	573 Watson Lake	BRR00045	Unknown/Other	1	1.25
2008-09-22	12:45	571 Whitehorse	BAC00020	Unknown/Other	3	1.25
2008-09-23	18:45	571 Whitehorse	RJZ00168	Defective Equipment	1	2.50
2008-09-24	15:00	571 Whitehorse	BAC00022	Defective Equipment	1	0.60
2008-09-24	13:00	571 Whitehorse	BAC00021	Unknown/Other	1	1.60
2008-09-28	20:00	571 Whitehorse	RTW00132	Adverse Weather	1	0.35
2008-09-28	11:30	571 Whitehorse	AMI00052	Foreign Interference	6	0.80
2008-09-29	2:30	571 Whitehorse	AMI00055A	Foreign Interference	2,168	0.35
2008-09-29	23:15	571 Whitehorse	AMI00055	Foreign Interference	2,168	0.35

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2008-09-29	22:50	571 Whitehorse	AMI00054	Foreign Interference	368	0.15
2008-09-29	21:00	571 Whitehorse	AMI00053	Foreign Interference	543	9.50
2008-09-30	10:00	572 Haines Junction	TGG00147	Adverse Weather	1	1.60
2008-09-30	10:00	572 Haines Junction	TGG00146	Adverse Weather	1	1.50
2008-09-30	9:30	572 Haines Junction	TGG00145	Adverse Weather	1	1.35
2008-09-30	9:30	572 Haines Junction	TGG00144	Adverse Weather	1	1.25
2008-09-30	9:13	572 Haines Junction	TGG00143	Adverse Weather	10	0.35
2008-09-30	8:30	572 Haines Junction	TGG00141	Adverse Weather	1	0.50
2008-09-30	8:25	572 Haines Junction	TGG00140	Adverse Weather	10	0.08
2008-09-30	7:50	572 Haines Junction	TGG00139	Adverse Weather	1	0.50
2008-09-30	3:30	572 Haines Junction	TGG00138	Adverse Weather	1	4.65
2008-09-30	3:30	572 Haines Junction	TGG00137	Adverse Weather	5	4.35
2008-09-30	9:20	572 Haines Junction	TGG00142	Adverse Weather	332	0.08
2008-10-01	18:00	571 Whitehorse	RTW00132A	Foreign Interference	1	0.80
2008-10-03	14:00	576 Teslin	MSO00020	Trees	300	2.30
2008-10-05	0:04	575 Carmacks	THB00119G	Loss of Supply - Yukon Energy	280	0.08
2008-10-05	0:04	574 Carcross	THB00119A	Loss of Supply - Yukon Energy	300	0.77
2008-10-05	0:04	572 Haines Junction	THB00119F	Loss of Supply - Yukon Energy	490	0.08
2008-10-05	0:04	582 Ross River	THB00119E	Loss of Supply - Yukon Energy	218	0.08
2008-10-05	0:04	594 Deep Creek	THB00119D	Loss of Supply - Yukon Energy	41	0.83
2008-10-05	0:04	571 Whitehorse	THB00126	Loss of Supply - Yukon Energy	1,843	0.62
2008-10-05	0:04	585 Tagish	THB00119B	Loss of Supply - Yukon Energy	359	0.77
2008-10-05	0:04	576 Teslin	THB00119	Loss of Supply - Yukon Energy	334	0.77
2008-10-05	0:04	571 Whitehorse	THB00133	Loss of Supply - Yukon Energy	278	1.38
2008-10-05	0:04	571 Whitehorse	THB00123	Loss of Supply - Yukon Energy	1,767	1.51
2008-10-05	0:04	571 Whitehorse	THB00116	Loss of Supply - Yukon Energy	4,425	0.93
2008-10-05	0:04	592 Marsh Lake	THB00119C	Loss of Supply - Yukon Energy	444	0.77
2008-10-09	20:30	576 Teslin	BAC00023	Foreign Interference	3	6.50
2008-10-10	14:36	571 Whitehorse	RJZ00170	Trees	100	5.08
2008-10-10	17:35	571 Whitehorse	BAC00026	Trees	1	0.15
2008-10-10	14:20	571 Whitehorse	RTW00139	Trees	1,013	2.66
2008-10-10	14:36	571 Whitehorse	RJZ00173	Trees	70	5.08
2008-10-10	14:36	585 Tagish	RJZ00172	Trees	359	5.08
2008-10-10	14:36	574 Carcross	RJZ00171	Trees	296	5.08
2008-10-10	22:30	571 Whitehorse	THB00136	Defective Equipment	5	2.00
2008-10-10	22:00	571 Whitehorse	THB00135	Trees	1	2.00
2008-10-10	17:10	571 Whitehorse	BAC00025	Trees	1	0.15
2008-10-10	19:30	571 Whitehorse	BAC00027	Trees	24	2.75
2008-10-10	22:45	571 Whitehorse	BAC00028	Trees	1	0.15
2008-10-10	15:10	571 Whitehorse	BAC00024	Adverse Weather	1	0.60
2008-10-11	10:50	577 Destruction Bay	BAC00029	Defective Equipment	1	6.65
2008-10-12	11:30	572 Haines Junction	DRR00167L	Loss of Supply - Yukon Energy	490	0.08
2008-10-12	11:30	574 Carcross	DRR00167F	Loss of Supply - Yukon Energy	296	1.01
2008-10-12	11:30	594 Deep Creek	DRR00167I	Loss of Supply - Yukon Energy	41	0.65
2008-10-12	11:30	575 Carmacks	DRR00167J	Loss of Supply - Yukon Energy	280	0.08
2008-10-12	11:30	582 Ross River	DRR00167K	Loss of Supply - Yukon Energy	218	0.08
2008-10-12	11:30	571 Whitehorse	DRR00167	Loss of Supply - Yukon Energy	4,024	0.46
2008-10-12	11:30	571 Whitehorse	DRR00167A	Loss of Supply - Yukon Energy	2,948	0.67
2008-10-12	11:30	571 Whitehorse	DRR00167B	Loss of Supply - Yukon Energy	1,126	0.89
2008-10-12	11:30	571 Whitehorse	DRR00167C	Loss of Supply - Yukon Energy	872	0.95
2008-10-12	11:30	571 Whitehorse	DRR00167D	Loss of Supply - Yukon Energy	961	1.06
2008-10-12	11:30	576 Teslin	DRR00167E	Loss of Supply - Yukon Energy	85	1.01
2008-10-12	11:30	592 Marsh Lake	DRR00167G	Loss of Supply - Yukon Energy	450	1.01
2008-10-12	11:30	585 Tagish	DRR00167H	Loss of Supply - Yukon Energy	360	1.01
2008-10-13	9:20	571 Whitehorse	DRR00168D	Loss of Supply - Yukon Energy	961	2.50
2008-10-13	9:20	594 Deep Creek	DRR00168I	Loss of Supply - Yukon Energy	41	2.14
2008-10-13	9:20	582 Ross River	DRR00168J	Loss of Supply - Yukon Energy	218	0.08
2008-10-13	9:20	572 Haines Junction	DRR00168K	Loss of Supply - Yukon Energy	490	0.08
2008-10-13	9:20	575 Carmacks	DRR00168L	Loss of Supply - Yukon Energy	280	0.08
2008-10-13	9:20	571 Whitehorse	DRR00168	Loss of Supply - Yukon Energy	2,795	1.40
2008-10-13	9:20	571 Whitehorse	DRR00168A	Loss of Supply - Yukon Energy	1,989	2.01
2008-10-13	9:20	576 Teslin	DRR00168E	Loss of Supply - Yukon Energy	85	2.50
2008-10-13	9:20	574 Carcross	DRR00168F	Loss of Supply - Yukon Energy	296	2.50
2008-10-13	9:20	585 Tagish	DRR00168G	Loss of Supply - Yukon Energy	360	2.50

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2008-10-13	9:20	592 Marsh Lake	DRR00168H	Loss of Supply - Yukon Energy	450	2.50
2008-10-13	9:20	571 Whitehorse	DRR00168C	Loss of Supply - Yukon Energy	1,099	2.49
2008-10-13	9:20	571 Whitehorse	DRR00168B	Loss of Supply - Yukon Energy	3,207	2.51
2008-10-16	10:36	571 Whitehorse	AMI00060	Foreign Interference	2	1.35
2008-10-20	1:10	571 Whitehorse	BSP00143	Loss of Supply - Yukon Energy	1,768	0.06
2008-10-22	15:00	576 Teslin	AMI00061	Trees	6	3.75
2008-10-22	19:00	576 Teslin	AMI00062	Trees	6	0.50
2008-10-22	22:30	576 Teslin	RSM00074	Trees	16	5.50
2008-10-22	23:58	590 Lower Post	WTT00348	Adverse Weather	99	0.10
2008-10-22	23:58	591 Upper Liard	WTT00347	Adverse Weather	135	0.10
2008-10-22	21:10	591 Upper Liard	WTT00345	Trees	33	1.50
2008-10-22	23:58	573 Watson Lake	WTT00346	Adverse Weather	817	0.10
2008-10-23	0:30	573 Watson Lake	WTT00353	Trees	18	2.35
2008-10-23	8:00	573 Watson Lake	WTT00356	Trees	1	3.45
2008-10-23	0:39	573 Watson Lake	WTT00349	Trees	817	0.85
2008-10-23	0:39	591 Upper Liard	WTT00352	Trees	135	0.25
2008-10-23	0:39	590 Lower Post	WTT00350	Trees	99	2.80
2008-10-23	8:00	571 Whitehorse	THB00140	Trees	1	1.50
2008-10-23	14:46	591 Upper Liard	BRR00044	Trees	1	0.60
2008-10-23	11:08	573 Watson Lake	WTT00355	Trees	18	0.15
2008-10-24	9:16	573 Watson Lake	WTT00357	Trees	1	0.80
2008-10-24	20:30	576 Teslin	THB00142	Trees	138	2.50
2008-10-24	17:20	572 Haines Junction	AMI00063	Trees	138	2.35
2008-10-24	16:00	571 Whitehorse	SS000155	Trees	822	1.41
2008-10-24	20:30	576 Teslin	THB00143	Trees	38	5.25
2008-10-24	21:00	573 Watson Lake	BRR00048	Trees	35	2.60
2008-10-24	21:00	591 Upper Liard	BRR00047	Trees	7	1.60
2008-10-24	18:40	573 Watson Lake	BRR00045A	Trees	2	1.10
2008-10-24	19:50	573 Watson Lake	BRR00046	Trees	2	1.25
2008-10-25	14:55	571 Whitehorse	AMI00065	Trees	1	0.25
2008-10-25	15:30	573 Watson Lake	BRR00049	Trees	1	1.35
2008-10-25	10:15	571 Whitehorse	AMI00064	Trees	8	0.35
2008-10-27	10:30	576 Teslin	RSM00075	Trees	1	2.80
2008-10-29	12:10	571 Whitehorse	THB00141	Human Element	160	1.15
2008-10-31	16:45	571 Whitehorse	RTW00140	Foreign Interference	1	1.00
2008-11-06	7:08	591 Upper Liard	WTT00359	Trees	2	1.75
2008-11-06	11:59	577 Destruction Bay	RAF00010	Human Element	20	0.35
2008-11-12	15:28	572 Haines Junction	PTM00072	Loss of Supply - Yukon Energy	453	0.06
2008-11-12	15:30	594 Deep Creek	DRR00169I	Loss of Supply - Yukon Energy	41	0.74
2008-11-12	15:30	571 Whitehorse	DRR00169A	Loss of Supply - Yukon Energy	1,883	0.55
2008-11-12	15:30	571 Whitehorse	DRR00169B	Loss of Supply - Yukon Energy	2,759	0.80
2008-11-12	15:30	571 Whitehorse	DRR00169C	Loss of Supply - Yukon Energy	1,173	0.70
2008-11-12	15:30	571 Whitehorse	DRR00169D	Loss of Supply - Yukon Energy	961	0.75
2008-11-12	15:30	585 Tagish	DRR00169F	Loss of Supply - Yukon Energy	360	0.60
2008-11-12	15:30	592 Marsh Lake	DRR00169G	Loss of Supply - Yukon Energy	450	0.60
2008-11-12	15:30	576 Teslin	DRR00169H	Loss of Supply - Yukon Energy	85	0.60
2008-11-12	15:28	575 Carmacks	PTM00069	Loss of Supply - Yukon Energy	280	0.08
2008-11-12	15:30	574 Carcross	DRR00169E	Loss of Supply - Yukon Energy	296	0.60
2008-11-12	15:30	571 Whitehorse	DRR00169	Loss of Supply - Yukon Energy	2,557	0.49
2008-11-12	15:28	582 Ross River	PTM00070	Loss of Supply - Yukon Energy	219	0.06
2008-11-18	11:38	573 Watson Lake	BRR00050	Trees	6	1.65
2008-11-19	15:40	571 Whitehorse	SS000156	Defective Equipment	2	0.30
2008-11-22	8:30	571 Whitehorse	THB00147	Foreign Interference	1	1.50
2008-11-22	14:45	582 Ross River	THB00146	Foreign Interference	8	0.90
2008-11-24	12:00	572 Haines Junction	TGG00156x	Foreign Interference	1	1.15
2008-11-24	21:00	576 Teslin	RSM00076	Adverse Weather	1	14.35
2008-11-24	10:35	571 Whitehorse	RJZ00176A	Defective Equipment	2	0.40
2008-12-01	14:30	572 Haines Junction	DRR00174K	Loss of Supply - Yukon Energy	490	0.08
2008-12-01	14:30	582 Ross River	DRR00174J	Loss of Supply - Yukon Energy	218	0.08
2008-12-01	14:30	594 Deep Creek	DRR00174I	Loss of Supply - Yukon Energy	41	0.89
2008-12-01	14:30	571 Whitehorse	DRR00174A	Loss of Supply - Yukon Energy	2,774	0.32
2008-12-01	14:30	575 Carmacks	DRR00174H	Loss of Supply - Yukon Energy	280	0.08
2008-12-01	14:30	571 Whitehorse	DRR00174B	Loss of Supply - Yukon Energy	3,662	0.51
2008-12-01	14:30	571 Whitehorse	DRR00174C	Loss of Supply - Yukon Energy	961	0.95

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2008-12-01	14:30	576 Teslin	DRR00174D	Loss of Supply - Yukon Energy	85	0.90
2008-12-01	14:30	574 Carcross	DRR00174E	Loss of Supply - Yukon Energy	296	0.90
2008-12-01	14:30	585 Tagish	DRR00174F	Loss of Supply - Yukon Energy	360	0.90
2008-12-01	14:30	592 Marsh Lake	DRR00174G	Loss of Supply - Yukon Energy	450	0.90
2008-12-01	14:30	571 Whitehorse	DRR00174	Loss of Supply - Yukon Energy	3,373	0.40
2008-12-05	9:00	571 Whitehorse	RTW00143	Defective Equipment	1	1.00
2008-12-06	15:00	571 Whitehorse	RJZ00177	Foreign Interference	3	0.65
2008-12-08	18:30	574 Carcross	RTW00144	Defective Equipment	1	6.00
2008-12-09	7:48	581 Stewart Crossing	PTM00073	Loss of Supply - Yukon Energy	31	0.06
2008-12-10	13:00	571 Whitehorse	RTW00145	Unknown/Other	1	1.00
2008-12-17	7:39	579 Old Crow	PTM00074	Loss of Supply - Yukon Electrical	181	0.01
2008-12-26	13:20	571 Whitehorse	BSP00146	Defective Equipment	1	0.65
2008-12-27	15:01	576 Teslin	MSO00021	Adverse Weather	318	1.47
2008-12-28	3:30	576 Teslin	MSO00022	Adverse Weather	318	0.87
2009-01-01	11:40	571 Whitehorse	RTW00146	Defective Equipment	1	1.58
2009-01-03	6:23	590 Lower Post	JES000064	Loss of Supply - Yukon Electrical	91	0.35
2009-01-03	7:00	599 Good Hope Lake	RP200020	Defective Equipment	25	4.00
2009-01-03	6:23	591 Upper Liard	JES00065	Defective Equipment	116	0.35
2009-01-04	15:30	571 Whitehorse	DRR00170	Foreign Interference	1	0.75
2009-01-04	14:50	592 Marsh Lake	RTW00147	Adverse Weather	6	1.67
2009-01-05	12:10	576 Teslin	BSP00147	Adverse Weather	1	0.08
2009-01-05	2:45	571 Whitehorse	RTW00148	Adverse Weather	6	1.50
2009-01-05	2:26	590 Lower Post	BRR00052	Adverse Weather	91	4.50
2009-01-06	20:15	571 Whitehorse	DRR00172	Adverse Weather	6	1.50
2009-01-06	5:00	585 Tagish	RTW00149	Adverse Weather	1	2.00
2009-01-06	8:30	590 Lower Post	BRR00053	Adverse Weather	1	1.23
2009-01-06	14:00	571 Whitehorse	SS000157	Foreign Interference	6	1.00
2009-01-06	16:20	591 Upper Liard	WTT00363	Unknown/Other	116	0.20
2009-01-06	16:20	590 Lower Post	WTT00362	Unknown/Other	91	0.20
2009-01-07	18:15	599 Good Hope Lake	RPL00021	Defective Equipment	25	0.50
2009-01-07	9:30	577 Destruction Bay	BSP00148	Defective Equipment	1	28.50
2009-01-08	17:30	572 Haines Junction	TGG00151	Unknown/Other	2	2.75
2009-01-08	22:35	571 Whitehorse	RJZ00178	Adverse Weather	2	1.17
2009-01-08	13:25	571 Whitehorse	AMI00072	Defective Equipment	406	0.33
2009-01-09	8:30	591 Upper Liard	WTT00364	Adverse Weather	1	1.83
2009-01-09	3:00	594 Deep Creek	SS000158	Adverse Weather	11	5.67
2009-01-09	2:30	571 Whitehorse	RJZ00179	Adverse Weather	522	2.34
2009-01-09	10:59	583 Pelly Crossing	PTM00075	Loss of Supply - Yukon Electrical	163	0.90
2009-01-09	6:00	574 Carcross	MSO00025	Adverse Weather	1	1.67
2009-01-09	15:20	571 Whitehorse	RSM00079	Adverse Weather	1	0.13
2009-01-09	3:00	571 Whitehorse	RSM00077	Adverse Weather	1	6.43
2009-01-10	22:30	583 Pelly Crossing	RJZ00181	Loss of Supply - Yukon Energy	95	7.08
2009-01-10	0:30	571 Whitehorse	SS000159	Adverse Weather	2	1.25
2009-01-10	22:20	571 Whitehorse	RJZ00180	Unknown/Other	2,202	0.81
2009-01-11	20:10	599 Good Hope Lake	RDL00022	Loss of Supply - Yukon Electrical	25	3.33
2009-01-11	10:00	573 Watson Lake	BRR00054	Unknown/Other	2	0.67
2009-01-11	12:12	572 Haines Junction	TGG00154	Adverse Weather	4	0.80
2009-01-12	8:31	571 Whitehorse	MSO00024	Adverse Weather	7	0.98
2009-01-12	8:55	591 Upper Liard	WTT00365	Adverse Weather	35	3.13
2009-01-12	9:48	590 Lower Post	BRR00055	Unknown/Other	87	2.18
2009-01-12	13:00	571 Whitehorse	BAC00030	Adverse Weather	11	1.33
2009-01-12	7:20	571 Whitehorse	MSO00023	Adverse Weather	1	0.75
2009-01-12	12:50	571 Whitehorse	MSO00026	Adverse Weather	1	1.05
2009-01-12	7:00	571 Whitehorse	SS000160	Adverse Weather	4	1.75
2009-01-12	19:30	571 Whitehorse	DJC00001	Adverse Weather	2	0.33
2009-01-13	17:00	574 Carcross	DJC00002	Trees	3	1.17
2009-01-13	14:40	573 Watson Lake	BRR00056	Unknown/Other	7	1.58
2009-01-14	13:45	571 Whitehorse	RSM00080	Adverse Weather	60	1.33
2009-01-14	7:45	571 Whitehorse	SS000161	Adverse Weather	5	3.50
2009-01-15	14:15	571 Whitehorse	RJZ00184	Adverse Weather	40	1.25
2009-01-16	21:45	584 Swift River	AMI00066	Defective Equipment	2	6.50
2009-01-17	22:15	574 Carcross	AMI00068	Trees	1	3.25
2009-01-17	21:45	571 Whitehorse	AMI00067	Trees	2	2.50
2009-01-18	14:10	573 Watson Lake	WTT00366	Adverse Weather	6	0.50

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2009-01-18	3:00	592 Marsh Lake	AMI00069	Trees	1	9.75
2009-01-21	6:41	591 Upper Liard	JES00068	Loss of Supply - Yukon Electrical	116	0.17
2009-01-21	1:20	571 Whitehorse	SS000164	Adverse Weather	113	0.70
2009-01-21	6:41	590 Lower Post	JES00067	Loss of Supply - Yukon Electrical	91	0.28
2009-01-26	19:30	574 Carcross	BAC00031	Adverse Weather	2	2.00
2009-01-27	14:00	576 Teslin	BAC00033	Adverse Weather	1	2.25
2009-01-28	13:15	571 Whitehorse	RTW00150	Adverse Weather	10	0.98
2009-01-28	13:40	571 Whitehorse	RTW00151	Adverse Weather	3	1.00
2009-01-28	15:00	573 Watson Lake	BRR00055BRR00	Defective Equipment	7	1.25
2009-01-29	19:23	573 Watson Lake	WTT00367	Defective Equipment	9	0.62
2009-01-29	13:00	571 Whitehorse	SS000164A	Foreign Interference	1	0.83
2009-01-29	20:00	591 Upper Liard	WTT00368	Defective Equipment	1	1.42
2009-01-30	6:45	571 Whitehorse	THB00151	Adverse Weather	1	0.93
2009-01-30	14:00	571 Whitehorse	DJC00005	Adverse Weather	17	1.50
2009-01-30	14:30	571 Whitehorse	AMI00071	Trees	1	0.25
2009-01-30	9:20	591 Upper Liard	WTT00370	Adverse Weather	9	0.96
2009-01-30	7:30	571 Whitehorse	DJC00004	Adverse Weather	1	0.38
2009-01-30	11:39	585 Tagish	SS000166	Adverse Weather	1	2.85
2009-01-30	7:30	574 Carcross	SS000165	Adverse Weather	303	1.92
2009-01-30	7:30	591 Upper Liard	WTT00369	Defective Equipment	33	1.32
2009-01-31	16:00	571 Whitehorse	RTW00152	Defective Equipment	1	2.50
2009-02-01	12:10	573 Watson Lake	WTT00371	Adverse Weather	2	1.25
2009-02-02	16:00	571 Whitehorse	RTW00153	Unknown/Other	15	1.33
2009-02-03	15:30	585 Tagish	RTW00154	Adverse Weather	8	2.95
2009-02-05	15:50	571 Whitehorse	SMB00002	Human Element	2	0.50
2009-02-07	7:35	571 Whitehorse	DRR00175	Adverse Weather	2	0.58
2009-02-07	11:20	576 Teslin	RTW00156	Adverse Weather	1	6.20
2009-02-07	13:00	571 Whitehorse	RTW00155	Adverse Weather	2	1.17
2009-02-09	10:00	571 Whitehorse	RJZ00185	Adverse Weather	5	0.92
2009-02-09	17:30	571 Whitehorse	DRR00176	Human Element	1	0.67
2009-02-10	13:30	571 Whitehorse	RJZ00187	Adverse Weather	2	-
2009-02-10	10:38	571 Whitehorse	RJZ00186	Adverse Weather	3	0.88
2009-02-16	5:30	571 Whitehorse	RTW00157	Defective Equipment	1	4.33
2009-02-16	12:15	571 Whitehorse	RTW00158	Foreign Interference	3	1.00
2009-02-16	9:40	573 Watson Lake	WTT00375	Defective Equipment	2	0.83
2009-02-19	20:30	571 Whitehorse	RSM00081	Foreign Interference	1	13.80
2009-02-21	20:40	571 Whitehorse	AMI00076	Loss of Supply - Yukon Energy	55	0.17
2009-02-21	13:15	571 Whitehorse	RSM00082	Adverse Weather	1	1.75
2009-02-21	14:45	585 Tagish	RSM00003	Adverse Weather	12	0.75
2009-02-24	22:45	571 Whitehorse	AMI00080	Defective Equipment	112	1.25
2009-02-26	13:45	571 Whitehorse	GLAP0001	Foreign Interference	32	0.70
2009-03-01	7:00	577 Destruction Bay	BSP00150	Defective Equipment	150	6.42
2009-03-07	14:15	576 Teslin	MSO00028	Adverse Weather	1	0.08
2009-03-07	7:59	592 Marsh Lake	MSO00027	Trees	1	1.77
2009-03-10	18:02	571 Whitehorse	MSO00029	Defective Equipment	2	1.13
2009-03-12	13:00	585 Tagish	BAC00035	Adverse Weather	1	0.33
2009-03-12	13:40	571 Whitehorse	RJZ00188	Foreign Interference	1	0.55
2009-03-13	13:30	571 Whitehorse	RSM00084	Foreign Interference	12	0.83
2009-03-14	17:15	571 Whitehorse	RTW00160	Defective Equipment	1	0.67
2009-03-16	14:50	571 Whitehorse	RTW00161	Defective Equipment	1	2.33
2009-03-19	8:00	576 Teslin	DJC00007	Trees	1	3.00
2009-03-22	14:05	571 Whitehorse	RJZ00189	Defective Equipment	265	2.10
2009-03-25	10:50	571 Whitehorse	RJZ00191	Foreign Interference	1	1.58
2009-03-25	16:30	573 Watson Lake	WTT00381	Defective Equipment	8	0.88
2009-03-26	15:02	571 Whitehorse	MSO00030	Trees	760	1.53
2009-03-28	4:00	572 Haines Junction	TGG00156	Defective Equipment	1	5.17
2009-04-01	12:55	579 Old Crow	RAF00012	Human Element	189	1.22
2009-04-01	18:25	579 Old Crow	RAF00013	Loss of Supply - Yukon Electrical	189	0.02
2009-04-02	9:30	573 Watson Lake	WTT00384	Foreign Interference	8	0.25
2009-04-06	11:30	571 Whitehorse	SS000172	Foreign Interference	1	1.50
2009-04-08	16:45	571 Whitehorse	SS000173	Foreign Interference	5	0.38
2009-04-16	8:50	571 Whitehorse	RTW00162	Foreign Interference	1	4.53
2009-04-16	8:57	576 Teslin	WAF0416-576	Loss of Supply - Yukon Energy	341	1.15
2009-04-16	8:57	594 Deep Creek	WAF0416-594	Loss of Supply - Yukon Energy	45	0.83

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2009-04-16	8:57	571 Whitehorse	WAF0416-571	Loss of Supply - Yukon Energy	10,780	0.87
2009-04-16	8:57	572 Haines Junction	WAF0416-572	Loss of Supply - Yukon Energy	441	0.25
2009-04-16	8:57	575 Carmacks	WAF0416-575	Loss of Supply - Yukon Energy	291	0.05
2009-04-16	8:57	582 Ross River	WAF0416-582	Loss of Supply - Yukon Energy	218	0.05
2009-04-16	8:57	583 Pelly Crossing	WAF0416-583	Loss of Supply - Yukon Energy	177	0.30
2009-04-16	8:57	585 Tagish	WAF0416-585	Loss of Supply - Yukon Energy	371	1.15
2009-04-16	8:57	592 Marsh Lake	WAF0416-592	Loss of Supply - Yukon Energy	447	1.15
2009-04-16	10:04	571 Whitehorse	RTW00161A	Unknown/Other	543	0.55
2009-04-16	8:57	574 Carcross	WAF0416-574	Loss of Supply - Yukon Energy	303	1.15
2009-04-17	10:00	571 Whitehorse	RJZ00194	Foreign Interference	9	2.83
2009-04-18	11:40	575 Carmacks	THB00159	Defective Equipment	3	2.33
2009-04-20	18:50	571 Whitehorse	THB00160	Foreign Interference	1	1.00
2009-04-21	9:12	571 Whitehorse	BSP00153	Trees	28	2.47
2009-04-21	7:10	590 Lower Post	BRR00060	Defective Equipment	91	0.38
2009-04-21	7:10	591 Upper Liard	BRR00061	Loss of Supply - Yukon Electrical	116	0.38
2009-04-21	7:10	573 Watson Lake	BRR00062	Loss of Supply - Yukon Electrical	752	0.30
2009-04-22	10:10	577 Destruction Bay	PTM00076	Loss of Supply - Yukon Electrical	150	0.05
2009-04-26	13:20	571 Whitehorse	RJZ00195	Foreign Interference	2	0.78
2009-04-29	9:40	573 Watson Lake	BRR00064	Foreign Interference	1	0.58
2009-05-01	16:00	571 Whitehorse	RSM00086	Foreign Interference	10	7.93
2009-05-01	21:00	571 Whitehorse	DJC00009	Scheduled	20	2.75
2009-05-01	19:40	571 Whitehorse	SS000176	Human Element	1	-
2009-05-02	8:00	575 Carmacks	RSM00087	Foreign Interference	2	3.55
2009-05-04	8:40	571 Whitehorse	RSM00088	Foreign Interference	5	0.62
2009-05-06	10:45	571 Whitehorse	RSM00089	Foreign Interference	2	1.33
2009-05-09	12:00	571 Whitehorse	BSP00154	Foreign Interference	1	0.67
2009-05-09	9:40	571 Whitehorse	RJZ00196	Foreign Interference	1	0.17
2009-05-12	18:00	571 Whitehorse	RJZ00197	Foreign Interference	10	0.75
2009-05-19	19:00	573 Watson Lake	BRR00065	Foreign Interference	1	0.83
2009-05-22	19:50	571 Whitehorse	THB00162	Foreign Interference	4	0.92
2009-05-28	22:22	571 Whitehorse	SS000180	Trees	2	0.13
2009-05-29	9:55	571 Whitehorse	RSM00090	Foreign Interference	8	0.70
2009-05-30	11:45	573 Watson Lake	BRR00066	Lightning	20	0.75
2009-05-31	21:00	571 Whitehorse	DJC00010	Human Element	1	9.67
2009-06-03	7:00	571 Whitehorse	SS000181	Foreign Interference	7	2.15
2009-06-04	16:00	571 Whitehorse	DJC00011	Defective Equipment	1	3.50
2009-06-07	10:00	576 Teslin	AMI00081	Foreign Interference	1	2.50
2009-06-08	7:43	590 Lower Post	BRR00072	Loss of Supply - Yukon Electrical	91	0.17
2009-06-08	7:43	591 Upper Liard	BRR00070	Loss of Supply - Yukon Electrical	124	0.18
2009-06-08	7:43	573 Watson Lake	BRR00069	Defective Equipment	752	0.18
2009-06-08	7:03	591 Upper Liard	BRR00071	Loss of Supply - Yukon Electrical	124	0.15
2009-06-11	21:09	571 Whitehorse	BSP00158	Adverse Environment	75	2.03
2009-06-11	18:45	571 Whitehorse	BSP00157	Foreign Interference	1	1.08
2009-06-11	15:35	571 Whitehorse	RSM00091	Loss of Supply - Yukon Energy	4,984	1.47
2009-06-13	12:45	571 Whitehorse	BSP00161	Trees	1	1.25
2009-06-13	12:10	571 Whitehorse	BSP00160	Adverse Weather	1	0.58
2009-06-14	6:55	572 Haines Junction	TGG00162	Foreign Interference	2	0.83
2009-06-15	9:00	585 Tagish	BAC00037	Foreign Interference	1	2.00
2009-06-17	21:00	574 Carcross	BAC00038	Unknown/Other	3	1.50
2009-06-20	2:30	585 Tagish	MSO00032	Defective Equipment	24	4.02
2009-06-22	9:30	573 Watson Lake	BRR00074	Defective Equipment	2	1.00
2009-06-23	20:55	571 Whitehorse	DRR00182	Foreign Interference	12	0.58
2009-06-23	19:13	581 Stewart Crossing	DRR00181	Loss of Supply - Yukon Energy	31	0.08
2009-06-23	14:40	585 Tagish	BAC00039	Foreign Interference	371	1.58
2009-06-25	16:10	573 Watson Lake	BRR00075	Foreign Interference	116	0.70
2009-06-26	17:30	571 Whitehorse	SS000182	Foreign Interference	12	1.25
2009-06-29	11:01	571 Whitehorse	MSO00031	Unknown/Other	172	1.23
2009-06-29	18:30	571 Whitehorse	SS0000187	Trees	6	22.00
2009-06-30	17:00	573 Watson Lake	RSM00092	Lightning	4	4.00
2009-07-02	14:00	573 Watson Lake	RSM00093	Scheduled	70	1.47
2009-07-03	11:10	571 Whitehorse	WAF0703-571	Loss of Supply - Yukon Energy	3,889	0.19
2009-07-03	11:10	585 Tagish	WAF0703-585	Loss of Supply - Yukon Energy	371	0.22
2009-07-03	11:10	575 Carmacks	WAF0703-575	Loss of Supply - Yukon Energy	291	0.05
2009-07-03	11:10	576 Teslin	WAF0703-576	Loss of Supply - Yukon Energy	341	0.12

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2009-07-03	11:10	574 Carcross	WAF0703-574	Loss of Supply - Yukon Energy	303	0.22
2009-07-03	11:10	592 Marsh Lake	WAF0703-592	Loss of Supply - Yukon Energy	447	0.22
2009-07-03	11:10	583 Pelly Crossing	WAF0703-583	Loss of Supply - Yukon Energy	177	0.27
2009-07-04	17:40	578 Beaver Creek	PTM00077	Loss of Supply - Yukon Electrical	119	0.05
2009-07-05	16:00	572 Haines Junction	TGG00157A	Foreign Interference	1	5.58
2009-07-06	18:59	572 Haines Junction	TGG00158A	Loss of Supply - Yukon Energy	598	0.38
2009-07-09	14:20	583 Pelly Crossing	WAF0709-583	Loss of Supply - Yukon Energy	177	0.87
2009-07-09	14:20	576 Teslin	WAF0709-576	Loss of Supply - Yukon Energy	341	0.12
2009-07-09	14:20	585 Tagish	WAF0709-585	Loss of Supply - Yukon Energy	371	0.58
2009-07-09	14:20	592 Marsh Lake	WAF0709-592	Loss of Supply - Yukon Energy	447	0.55
2009-07-09	14:20	582 Ross River	WAF0709-582	Loss of Supply - Yukon Energy	218	0.07
2009-07-09	14:20	574 Carcross	WAF0709-574	Loss of Supply - Yukon Energy	303	0.58
2009-07-09	15:22	571 Whitehorse	WAF0709B-571	Loss of Supply - Yukon Energy	3,964	0.32
2009-07-09	15:22	574 Carcross	WAF0709B-574	Loss of Supply - Yukon Energy	303	0.22
2009-07-09	15:22	592 Marsh Lake	WAF0709B-592	Loss of Supply - Yukon Energy	447	0.23
2009-07-09	14:20	575 Carmacks	WAF0709-575	Loss of Supply - Yukon Energy	291	0.08
2009-07-09	15:22	585 Tagish	WAF0709B-585	Loss of Supply - Yukon Energy	371	0.22
2009-07-09	15:22	576 Teslin	WAF0709B-576	Loss of Supply - Yukon Energy	341	0.22
2009-07-09	14:20	571 Whitehorse	WAF0709-571	Loss of Supply - Yukon Energy	3,964	0.42
2009-07-11	8:10	Blank	AMI00082	Foreign Interference	740	1.42
2009-07-11	8:00	571 Whitehorse	RSM00094	Lightning	4	2.97
2009-07-11	12:30	576 Teslin	BAC00040	Foreign Interference	5	3.00
2009-07-12	9:30	572 Haines Junction	TGG00159	Defective Equipment	1	1.42
2009-07-12	21:44	594 Deep Creek	WAF0712-594	Loss of Supply - Yukon Energy	45	1.07
2009-07-12	21:44	575 Carmacks	WAF0712-575	Loss of Supply - Yukon Energy	291	0.05
2009-07-12	21:44	583 Pelly Crossing	WAF0712-583	Loss of Supply - Yukon Energy	177	1.67
2009-07-12	21:44	571 Whitehorse	WAF0712-571	Loss of Supply - Yukon Energy	6,039	0.46
2009-07-13	9:05	585 Tagish	BAC00041	Foreign Interference	1	2.50
2009-07-14	9:00	594 Deep Creek	MSO00033	Foreign Interference	45	2.08
2009-07-15	13:50	571 Whitehorse	MSO00034	Lightning	20	1.55
2009-07-15	20:30	577 Destruction Bay	TGG00159A	Trees	1	0.33
2009-07-15	11:33	Blank	RJZ00201	Loss of Supply - Yukon Energy	513	0.08
2009-07-16	14:30	572 Haines Junction	PTM00078	Foreign Interference	133	0.25
2009-07-18	11:15	576 Teslin	BSP00165	Unknown/Other	1	2.33
2009-07-19	13:20	571 Whitehorse	BAC00043	Foreign Interference	1	3.17
2009-07-19	13:20	571 Whitehorse	BAC00042	Foreign Interference	4	1.17
2009-07-25	8:30	571 Whitehorse	RTW00165	Foreign Interference	1	5.17
2009-07-25	15:30	571 Whitehorse	THB00179	Unknown/Other	6	0.83
2009-07-25	11:30	571 Whitehorse	THB00178	Foreign Interference	10	0.50
2009-07-26	11:18	591 Upper Liard	JES00072	Trees	116	0.33
2009-07-26	14:20	590 Lower Post	JES00076	Loss of Supply - Yukon Electrical	91	0.20
2009-07-26	11:18	573 Watson Lake	JES00071	Trees	752	0.88
2009-07-26	11:18	590 Lower Post	JES00073	Trees	91	1.00
2009-07-26	14:20	573 Watson Lake	JES00074	Defective Equipment	424	0.20
2009-07-26	14:20	591 Upper Liard	JES00075	Defective Equipment	116	0.20
2009-07-27	10:30	576 Teslin	MSO00035	Trees	12	3.25
2009-07-28	19:22	591 Upper Liard	BRR00077	Defective Equipment	47	1.39
2009-07-29	4:51	571 Whitehorse	THB00177	Foreign Interference	1,013	0.43
2009-07-29	10:30	571 Whitehorse	RSM0095	Foreign Interference	20	0.42
2009-07-29	11:30	571 Whitehorse	THB00180	Unknown/Other	1	1.00
2009-08-01	10:25	571 Whitehorse	DRR00188	Foreign Interference	10	0.42
2009-08-04	9:20	571 Whitehorse	SS000190	Foreign Interference	1	0.67
2009-08-07	8:27	571 Whitehorse	SS000192	Foreign Interference	12	1.22
2009-08-08	5:27	582 Ross River	THB00185	Unknown/Other	218	3.80
2009-08-08	15:30	576 Teslin	SS000193	Unknown/Other	1	2.17
2009-08-09	20:30	575 Carmacks	SS000194	Foreign Interference	1	5.75
2009-08-09	16:50	571 Whitehorse	THB00186	Unknown/Other	585	0.42
2009-08-10	18:45	571 Whitehorse	SS000195	Foreign Interference	1	1.42
2009-08-10	11:00	571 Whitehorse	DJC00013	Trees	4	3.00
2009-08-10	17:00	571 Whitehorse	DJC00012	Defective Equipment	2	15.67
2009-08-10	8:30	573 Watson Lake	BRR00078	Foreign Interference	1	0.52
2009-08-12	19:30	571 Whitehorse	THB00187	Foreign Interference	2	0.40
2009-08-16	19:37	571 Whitehorse	RJZ00202	Foreign Interference	30	0.42
2009-08-16	6:00	571 Whitehorse	AMI00084	Trees	3	1.50

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2009-08-16	14:10	592 Marsh Lake	AMI00085	Trees	3	1.67
2009-08-17	9:30	583 Pelly Crossing	AMI00086	Foreign Interference	1	4.17
2009-08-17	12:30	572 Haines Junction	TGG00163	Unknown/Other	472	0.75
2009-08-18	15:21	581 Stewart Crossing	NC000010	Lightning	31	0.13
2009-08-20	12:27	572 Haines Junction	NC000011	Unknown/Other	492	0.10
2009-08-21	6:27	573 Watson Lake	JES00079	Defective Equipment	752	0.66
2009-08-21	6:27	590 Lower Post	JES00077	Loss of Supply - Yukon Electrical	91	0.78
2009-08-21	21:00	571 Whitehorse	BAC00044	Foreign Interference	1	1.00
2009-08-21	6:27	591 Upper Liard	JES00078	Defective Equipment	116	0.25
2009-08-22	14:15	571 Whitehorse	BAC00045	Foreign Interference	2	1.00
2009-08-23	12:15	576 Teslin	YAF0823-576	Defective Equipment	341	2.06
2009-08-23	12:15	583 Pelly Crossing	YAF0823-583	Defective Equipment	177	0.83
2009-08-23	12:15	574 Carcross	YAF0823-574	Defective Equipment	303	0.08
2009-08-23	9:50	571 Whitehorse	BSP00169	Foreign Interference	7	0.50
2009-08-23	12:15	585 Tagish	YAF0823-585	Defective Equipment	371	0.08
2009-08-23	12:15	575 Carmacks	YAF0823-575	Defective Equipment	291	0.08
2009-08-23	12:15	592 Marsh Lake	YAF0823-592	Defective Equipment	447	7.67
2009-08-23	12:15	571 Whitehorse	YAF0823-571	Defective Equipment	2,940	0.45
2009-08-24	14:40	573 Watson Lake	RRR00079	Unknown/Other	1	1.08
2009-08-26	15:00	575 Carmacks	RTW00166	Unknown/Other	1	0.25
2009-08-27	9:00	573 Watson Lake	BRR00080	Unknown/Other	20	0.58
2009-08-27	22:00	576 Teslin	DJC00014	Defective Equipment	1	13.50
2009-08-28	11:15	571 Whitehorse	RSM00096	Foreign Interference	10	1.00
2009-08-29	13:30	571 Whitehorse	SS000198	Foreign Interference	1	2.50
2009-08-30	11:30	582 Ross River	SS000199	Foreign Interference	1	7.25
2009-08-31	8:00	571 Whitehorse	RTW00167	Foreign Interference	1	1.20
2009-09-01	8:15	571 Whitehorse	RSM0097	Unknown/Other	10	0.88
2009-09-02	6:02	591 Upper Liard	JES00082	Defective Equipment	116	0.28
2009-09-02	6:02	590 Lower Post	JES00081	Loss of Supply - Yukon Electrical	91	0.27
2009-09-02	6:02	573 Watson Lake	JES00080	Defective Equipment	752	0.28
2009-09-04	8:55	571 Whitehorse	SS000200	Defective Equipment	713	0.38
2009-09-04	18:15	571 Whitehorse	RSM00098	Defective Equipment	2	0.33
2009-09-05	11:00	571 Whitehorse	RSM00099	Human Element	1	1.00
2009-09-06	12:00	571 Whitehorse	RTW00168	Unknown/Other	1	10.83
2009-09-09	10:30	575 Carmacks	RTW00169	Foreign Interference	1	1.00
2009-09-10	9:30	571 Whitehorse	SS000201	Foreign Interference	6	0.67
2009-09-10	16:00	571 Whitehorse	MSO00038	Trees	2	2.33
2009-09-12	8:55	571 Whitehorse	MSO00039A	Foreign Interference	1	1.33
2009-09-14	23:13	571 Whitehorse	WAF0914-571	Loss of Supply - Yukon Energy	3,889	0.27
2009-09-14	17:00	571 Whitehorse	SS000203	Foreign Interference	1	0.50
2009-09-14	23:13	583 Pelly Crossing	WAF0914-583	Loss of Supply - Yukon Energy	177	0.60
2009-09-14	23:13	574 Carcross	WAF0914-574	Loss of Supply - Yukon Energy	303	0.15
2009-09-14	23:13	585 Tagish	WAF0914-585	Loss of Supply - Yukon Energy	371	0.15
2009-09-14	23:13	576 Teslin	WAF0914-576	Loss of Supply - Yukon Energy	341	0.21
2009-09-14	23:13	592 Marsh Lake	WAF0914-592	Loss of Supply - Yukon Energy	447	0.15
2009-09-22	15:25	571 Whitehorse	RTW00170	Foreign Interference	5	0.75
2009-09-25	7:30	571 Whitehorse	RTW00171	Defective Equipment	10	3.70
2009-09-26	3:30	571 Whitehorse	BSP00170	Defective Equipment	12	5.30
2009-09-29	13:20	573 Watson Lake	BRR00081	Defective Equipment	1	1.00
2009-09-29	18:15	571 Whitehorse	DRR00189	Human Element	1	0.75
2009-10-01	12:20	581 Stewart Crossing	RJZ00206	Trees	2	1.75
2009-10-04	13:11	572 Haines Junction	TGG00168	Human Element	9	0.35
2009-10-04	19:40	571 Whitehorse	MSO00041	Foreign Interference	1	1.48
2009-10-05	10:20	571 Whitehorse	RJZ00207	Defective Equipment	2	1.88
2009-10-05	16:00	571 Whitehorse	SS000206	Adverse Weather	1	4.50
2009-10-06	10:07	573 Watson Lake	JES00084	Defective Equipment	300	0.10
2009-10-06	18:00	572 Haines Junction	TGG00169	Defective Equipment	1	0.33
2009-10-06	10:07	590 Lower Post	JES00083	Loss of Supply - Yukon Electrical	91	0.10
2009-10-07	14:26	573 Watson Lake	JES00085	Defective Equipment	300	0.08
2009-10-07	20:05	576 Teslin	MSO00039	Foreign Interference	2	3.00
2009-10-07	17:20	571 Whitehorse	WAF1007-571	Loss of Supply - Yukon Energy	1,929	0.37
2009-10-07	18:40	583 Pelly Crossing	THB00195	Loss of Supply - Yukon Energy	177	0.08
2009-10-09	4:45	571 Whitehorse	RSM00100	Trees	20	3.25
2009-10-10	11:20	573 Watson Lake	BAC00046	Foreign Interference	1	5.42

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2009-10-15	18:30	577 Destruction Bay	TGG00171	Human Element	150	0.03
2009-10-15	9:15	579 Old Crow	PTM00081	Unknown/Other	189	0.03
2009-10-17	6:30	571 Whitehorse	THB00199	Unknown/Other	1	1.25
2009-10-20	16:05	571 Whitehorse	RJZ00210	Foreign Interference	1	0.50
2009-10-21	21:40	573 Watson Lake	BRR00082	Unknown/Other	2	0.50
2009-10-21	15:55	571 Whitehorse	MSO00040	Trees	4	0.75
2009-10-22	18:30	571 Whitehorse	RSM00101	Defective Equipment	1	0.50
2009-10-23	9:35	571 Whitehorse	SS000207	Foreign Interference	10	0.92
2009-10-25	19:08	578 Beaver Creek	PTM00080	Loss of Supply - Yukon Electrical	119	0.07
2009-10-26	5:43	571 Whitehorse	AMI00090	Unknown/Other	4	1.78
2009-10-27	11:45	571 Whitehorse	RJZ00211	Foreign Interference	34	3.67
2009-10-27	17:00	576 Teslin	DJC00019	Unknown/Other	1	17.78
2009-10-27	16:00	571 Whitehorse	DJC00021	Foreign Interference	2	1.92
2009-10-27	15:20	571 Whitehorse	RSM00103	Foreign Interference	8	0.67
2009-10-28	11:02	572 Haines Junction	WAF1028-572	Loss of Supply - Yukon Energy	441	0.09
2009-10-28	10:58	572 Haines Junction	TGG00172	Unknown/Other	490	0.15
2009-10-28	12:00	573 Watson Lake	BAC00048	Loss of Supply - Yukon Electrical	1	6.25
2009-10-30	7:35	579 Old Crow	PTM00083	Unknown/Other	189	0.03
2009-11-02	13:30	574 Carcross	RTW00172	Foreign Interference	23	1.01
2009-11-02	8:30	573 Watson Lake	BAC00049	Adverse Weather	1	2.25
2009-11-02	17:30	579 Old Crow	PTM00083A	Loss of Supply - Yukon Electrical	195	0.03
2009-11-04	8:06	582 Ross River	WAF1104-582	Loss of Supply - Yukon Energy	218	0.12
2009-11-04	8:06	583 Pelly Crossing	WAF1104-583	Loss of Supply - Yukon Energy	177	0.20
2009-11-04	8:06	585 Tagish	WAF1104-585	Loss of Supply - Yukon Energy	371	0.90
2009-11-04	8:06	592 Marsh Lake	WAF1104-592	Loss of Supply - Yukon Energy	447	0.90
2009-11-04	8:06	594 Deep Creek	WAF1104-594	Loss of Supply - Yukon Energy	45	0.18
2009-11-04	8:06	575 Carmacks	WAF1104-575	Loss of Supply - Yukon Energy	291	0.08
2009-11-04	8:06	574 Carcross	WAF1104-574	Loss of Supply - Yukon Energy	303	0.90
2009-11-04	8:06	576 Teslin	WAF1104-576	Loss of Supply - Yukon Energy	341	0.08
2009-11-04	8:06	571 Whitehorse	WAF1104-571	Loss of Supply - Yukon Energy	10,780	0.72
2009-11-04	8:11	572 Haines Junction	TGG00175A	Loss of Supply - Yukon Energy	490	0.06
2009-11-04	8:06	572 Haines Junction	WAF1104-572	Loss of Supply - Yukon Energy	441	0.07
2009-11-04	13:25	573 Watson Lake	BAC00050	Human Element	33	0.67
2009-11-06	13:30	571 Whitehorse	BSP00172	Foreign Interference	1	7.17
2009-11-06	9:18	571 Whitehorse	SS000209	Foreign Interference	539	1.03
2009-11-09	19:10	573 Watson Lake	BAC00051	Defective Equipment	1	0.67
2009-11-09	8:07	579 Old Crow	PTM00084	Loss of Supply - Yukon Electrical	195	0.03
2009-11-10	8:25	571 Whitehorse	WAF1110-571	Loss of Supply - Yukon Energy	4,882	0.30
2009-11-10	11:55	577 Destruction Bay	PTM00085	Loss of Supply - Yukon Electrical	150	0.03
2009-11-10	8:25	583 Pelly Crossing	WAF1110-583	Loss of Supply - Yukon Energy	177	0.20
2009-11-10	8:25	594 Deep Creek	WAF1110-594	Loss of Supply - Yukon Energy	45	0.38
2009-11-10	8:25	575 Carmacks	WAF1110-575	Loss of Supply - Yukon Energy	291	0.08
2009-11-11	12:40	579 Old Crow	PTM00086	Loss of Supply - Yukon Electrical	195	0.03
2009-11-13	10:40	571 Whitehorse	RJZ00212	Foreign Interference	20	0.67
2009-11-14	14:18	583 Pelly Crossing	WAF1114-583	Loss of Supply - Yukon Energy	177	1.45
2009-11-14	19:55	572 Haines Junction	TGG00179	Adverse Weather	458	0.48
2009-11-14	21:20	572 Haines Junction	TGG00181	Adverse Weather	7	1.33
2009-11-14	16:34	571 Whitehorse	RTW00175	Trees	1	0.27
2009-11-14	16:30	571 Whitehorse	RTW00174	Defective Equipment	10	0.17
2009-11-14	10:45	571 Whitehorse	RTW00173	Defective Equipment	2	1.33
2009-11-14	7:35	576 Teslin	RJZ00213	Trees	105	4.42
2009-11-14	17:05	572 Haines Junction	TGG00178	Adverse Weather	1	3.00
2009-11-14	12:00	592 Marsh Lake	THB00202	Trees	21	1.28
2009-11-14	12:30	585 Tagish	THB00203	Trees	123	2.76
2009-11-14	15:45	585 Tagish	THB00204	Trees	294	0.92
2009-11-14	18:00	571 Whitehorse	DJC00021B	Trees	1	2.33
2009-11-14	14:18	582 Ross River	WAF1114-582	Loss of Supply - Yukon Energy	218	0.08
2009-11-14	12:45	572 Haines Junction	TGG00176	Adverse Weather	4	1.92
2009-11-14	10:30	572 Haines Junction	TGG00175	Adverse Weather	2	1.25
2009-11-14	14:18	594 Deep Creek	WAF1114-594	Loss of Supply - Yukon Energy	45	0.22
2009-11-14	20:53	572 Haines Junction	TGG00130	Adverse Weather	9	0.53
2009-11-14	14:18	575 Carmacks	WAF1114-575	Loss of Supply - Yukon Energy	291	0.08
2009-11-14	16:00	572 Haines Junction	TGG00177	Adverse Weather	9	2.00
2009-11-15	16:50	572 Haines Junction	TGG00182	Defective Equipment	3	0.90

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2009-11-18	16:50	572 Haines Junction	TGG00183	Adverse Weather	2	0.67
2009-11-24	14:30	573 Watson Lake	BRR00084	Trees	6	0.67
2009-11-25	18:00	571 Whitehorse	DRR00192	Unknown/Other	1	0.50
2009-11-26	18:40	571 Whitehorse	RSM00105	Adverse Weather	1	1.67
2009-11-26	13:00	571 Whitehorse	RSM00104	Defective Equipment	10	1.00
2009-11-30	9:35	575 Carmacks	WAF1130-575	Loss of Supply - Yukon Energy	291	0.08
2009-11-30	9:35	571 Whitehorse	WAF1130-571	Loss of Supply - Yukon Energy	4,882	0.05
2009-11-30	17:45	571 Whitehorse	RSM00106	Adverse Weather	2	1.50
2009-11-30	9:35	594 Deep Creek	WAF1130-594	Loss of Supply - Yukon Energy	45	0.08
2009-11-30	9:35	583 Pelly Crossing	WAF1130-583	Loss of Supply - Yukon Energy	177	0.12
2009-12-02	9:40	592 Marsh Lake	GLP00003	Trees	227	3.23
2009-12-10	15:55	594 Deep Creek	WAF1210-594	Loss of Supply - Yukon Energy	45	0.58
2009-12-10	15:55	571 Whitehorse	WAF1210-571	Loss of Supply - Yukon Energy	8,213	0.68
2009-12-10	15:55	572 Haines Junction	WAF1210-572	Loss of Supply - Yukon Energy	441	0.08
2009-12-10	15:55	575 Carmacks	WAF1210-575	Loss of Supply - Yukon Energy	291	0.08
2009-12-10	15:55	576 Teslin	WAF1210-576	Loss of Supply - Yukon Energy	341	0.08
2009-12-10	15:55	585 Tagish	WAF1210-585	Loss of Supply - Yukon Energy	371	0.37
2009-12-10	15:55	583 Pelly Crossing	WAF1210-583	Loss of Supply - Yukon Energy	177	0.22
2009-12-10	15:55	574 Carcross	WAF1210-574	Loss of Supply - Yukon Energy	303	0.37
2009-12-10	15:55	571 Whitehorse	DRR00193-571	Foreign Interference	2,567	0.69
2009-12-10	15:55	592 Marsh Lake	WAF1210-592	Loss of Supply - Yukon Energy	447	0.37
2009-12-10	15:55	582 Ross River	WAF1210-582	Loss of Supply - Yukon Energy	218	0.08
2009-12-12	20:45	585 Tagish	MSO00042	Adverse Weather	2	2.03
2009-12-14	13:15	571 Whitehorse	SS000211	Adverse Weather	80	0.42
2009-12-17	0:55	571 Whitehorse	DRR00195	Adverse Weather	75	0.67
2009-12-28	12:40	571 Whitehorse	SS0000212	Foreign Interference	1	0.50
2010-01-01	1:00	571 Whitehorse	THB00206	Human Element	1	-
2010-01-09	15:00	573 Watson Lake	BRR00089	Adverse Weather	1	1.33
2010-01-09	10:10	591 Upper Liard	BRR00087	Adverse Weather	120	0.17
2010-01-10	16:20	571 Whitehorse	AMI00092	Defective Equipment	6	2.92
2010-01-10	17:30	571 Whitehorse	AMI00093A	Adverse Weather	2	2.25
2010-01-10	22:57	577 Destruction Bay	TGG00185	Adverse Weather	150	0.36
2010-01-12	16:15	571 Whitehorse	RJZ00215	Unknown/Other	1	0.17
2010-01-13	20:50	575 Carmacks	MSO00043	Foreign Interference	1	3.00
2010-01-15	7:15	579 Old Crow	PTM00080A	Loss of Supply - Yukon Electrical	189	0.02
2010-01-16	13:10	571 Whitehorse	BSP00175	Adverse Weather	3	0.83
2010-01-16	10:00	571 Whitehorse	DJC00023	Foreign Interference	7	1.92
2010-01-18	16:30	571 Whitehorse	BSP00176	Defective Equipment	1	4.25
2010-01-19	11:00	571 Whitehorse	RSM00107	Adverse Weather	6	3.92
2010-01-19	8:00	571 Whitehorse	RTW00177	Foreign Interference	6	1.25
2010-01-21	16:08	581 Stewart Crossing	PTM00081A	Loss of Supply - Yukon Energy	31	0.07
2010-01-22	4:35	577 Destruction Bay	TGG00186	Adverse Weather	600	0.11
2010-01-22	7:07	577 Destruction Bay	TGG00186A	Adverse Weather	600	0.11
2010-01-22	10:01	577 Destruction Bay	TGG00186B	Adverse Weather	600	0.05
2010-01-22	10:25	577 Destruction Bay	TGG00187	Adverse Weather	6	3.18
2010-01-25	11:30	590 Lower Post	BRR00090	Unknown/Other	3	0.72
2010-01-25	12:13	571 Whitehorse	GLP00005	Foreign Interference	7	0.45
2010-01-28	13:45	571 Whitehorse	RTW00178	Adverse Weather	182	0.59
2010-01-29	16:40	571 Whitehorse	THB00208	Adverse Weather	10	0.83
2010-01-29	22:02	592 Marsh Lake	THB00209	Adverse Weather	6	1.48
2010-01-30	22:00	571 Whitehorse	DRR00196	Adverse Weather	1	9.25
2010-02-01	15:40	571 Whitehorse	DRR00197	Adverse Weather	1	2.17
2010-02-02	9:09	580 Keno City	DRR00198	Unknown/Other	56	0.08
2010-02-02	3:15	571 Whitehorse	THB00210	Adverse Weather	177	0.50
2010-02-02	16:16	581 Stewart Crossing	PTM00087	Loss of Supply - Yukon Energy	31	0.07
2010-02-03	17:00	585 Tagish	RSM00108	Trees	3	0.42
2010-02-06	18:00	571 Whitehorse	SS000215	Defective Equipment	1	5.00
2010-02-06	14:04	581 Stewart Crossing	PTM00088	Loss of Supply - Yukon Energy	31	0.07
2010-02-07	14:45	592 Marsh Lake	RJZ00216	Trees	2	1.25
2010-02-09	18:00	572 Haines Junction	TGG00189	Unknown/Other	1	21.83
2010-02-18	3:50	571 Whitehorse	AMI00094	Adverse Environment	2	-
2010-02-19	13:00	578 Beaver Creek	SS000218	Adverse Weather	1	6.75
2010-02-19	14:30	573 Watson Lake	BAC00052	Defective Equipment	1	1.50
2010-02-23	9:26	582 Ross River	PTM00089	Loss of Supply - Yukon Energy	218	0.05

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2010-02-24	15:30	571 Whitehorse	DJC00025	Foreign Interference	2	4.25
2010-02-25	11:00	572 Haines Junction	AMI00095	Defective Equipment	1	0.50
2010-02-27	16:03	582 Ross River	PTM00093	Loss of Supply - Yukon Energy	218	0.05
2010-02-27	12:00	571 Whitehorse	RSM00109	Foreign Interference	25	0.83
2010-02-27	16:03	583 Pelly Crossing	PTM00091	Loss of Supply - Yukon Energy	177	0.57
2010-02-27	16:03	575 Carmacks	PTM00092	Loss of Supply - Yukon Energy	291	0.10
2010-02-28	13:30	573 Watson Lake	BRR00091	Human Element	1	1.85
2010-03-01	17:33	583 Pelly Crossing	PTM00095	Loss of Supply - Yukon Energy	177	0.05
2010-03-01	15:45	583 Pelly Crossing	PTM00094	Loss of Supply - Yukon Energy	177	0.53
2010-03-05	19:42	571 Whitehorse	RJZ00217	Trees	1	1.80
2010-03-09	13:38	571 Whitehorse	RTW00179	Trees	26	2.03
2010-03-13	12:10	573 Watson Lake	BRR00092	Unknown/Other	31	1.08
2010-03-16	20:00	571 Whitehorse	THB00214	Foreign Interference	27	0.50
2010-03-16	13:30	571 Whitehorse	AMI00097	Unknown/Other	1	5.08
2010-03-21	10:10	571 Whitehorse	DRR00199	Foreign Interference	1	0.58
2010-03-22	17:11	571 Whitehorse	SS000221	Foreign Interference	1	2.32
2010-03-22	20:30	571 Whitehorse	DJC00028	Defective Equipment	1	5.00
2010-03-22	10:00	571 Whitehorse	SS000220	Foreign Interference	1	0.50
2010-03-28	13:26	583 Pelly Crossing	PTM00096	Loss of Supply - Yukon Energy	177	0.85
2010-03-28	13:26	575 Carmacks	PTM00097	Loss of Supply - Yukon Energy	291	0.08
2010-03-28	13:26	582 Ross River	PTM00098	Loss of Supply - Yukon Energy	218	0.05
2010-03-28	13:30	576 Teslin	SS000223	Trees	1	1.50
2010-03-30	15:35	583 Pelly Crossing	RJZ00219	Defective Equipment	1	3.92
2010-03-31	14:06	582 Ross River	RAF00014	Defective Equipment	219	0.05
2010-04-02	17:35	571 Whitehorse	RJZ00221	Foreign Interference	1	0.92
2010-04-02	7:35	571 Whitehorse	RJZ00220	Defective Equipment	1	0.87
2010-04-05	16:10	571 Whitehorse	RJZ00222	Foreign Interference	1	0.68
2010-04-06	4:14	575 Carmacks	PTM00099	Loss of Supply - Yukon Energy	291	0.10
2010-04-08	12:12	581 Stewart Crossing	GLP00007	Loss of Supply - Yukon Energy	31	0.08
2010-04-09	10:45	571 Whitehorse	AMI00098	Defective Equipment	15	0.75
2010-04-11	21:00	583 Pelly Crossing	RSM00110	Defective Equipment	1	19.92
2010-04-14	8:58	571 Whitehorse	RTW00180	Unknown/Other	45	2.65
2010-04-14	13:30	571 Whitehorse	BSP00178	Defective Equipment	1	4.00
2010-04-15	8:10	571 Whitehorse	RTW00181	Foreign Interference	5	0.88
2010-04-17	11:00	573 Watson Lake	BRR00093	Defective Equipment	7	1.13
2010-04-17	3:45	573 Watson Lake	BAC00053	Adverse Environment	1	-
2010-04-20	18:17	577 Destruction Bay	PTM00087A	Loss of Supply - Yukon Electrical	150	0.02
2010-04-20	9:55	571 Whitehorse	RSM00111	Foreign Interference	2	2.97
2010-04-22	9:00	571 Whitehorse	RTW00182	Foreign Interference	2	6.97
2010-04-23	7:00	571 Whitehorse	RSM00112	Defective Equipment	1	1.25
2010-04-24	18:45	571 Whitehorse	AMI00099	Foreign Interference	1	0.75
2010-04-24	9:30	571 Whitehorse	DRR000200	Unknown/Other	3	0.83
2010-04-26	20:01	573 Watson Lake	BRR00094	Defective Equipment	1	1.23
2010-04-26	12:40	571 Whitehorse	RTW00183	Defective Equipment	1	2.00
2010-04-27	15:10	591 Upper Liard	BRR00095	Adverse Weather	9	1.08
2010-05-01	7:00	571 Whitehorse	DJC00030	Foreign Interference	25	1.33
2010-05-02	12:30	571 Whitehorse	BSP00179	Human Element	1	0.08
2010-05-03	6:45	582 Ross River	BSP00180	Defective Equipment	4	5.75
2010-05-04	6:10	583 Pelly Crossing	RJZ00225	Unknown/Other	72	1.00
2010-05-06	8:00	571 Whitehorse	SS000224	Foreign Interference	3	1.75
2010-05-07	13:30	571 Whitehorse	RSM00115	Defective Equipment	2	0.92
2010-05-07	11:30	571 Whitehorse	RSM00114	Foreign Interference	1	1.25
2010-05-07	9:30	571 Whitehorse	SS000225	Defective Equipment	1	1.00
2010-05-14	9:40	572 Haines Junction	RTW00184	Unknown/Other	2	2.67
2010-05-14	19:52	576 Teslin	RJZ00230	Foreign Interference	1	2.80
2010-05-15	19:04	582 Ross River	DJC00035	Loss of Supply - Yukon Energy	216	0.97
2010-05-19	6:55	576 Teslin	DJC00033	Trees	91	0.65
2010-05-19	6:55	576 Teslin	DJC00034	Trees	290	0.65
2010-05-20	9:30	571 Whitehorse	RSM00116	Defective Equipment	1	1.75
2010-05-21	11:00	576 Teslin	SS000227	Foreign Interference	1	3.25
2010-05-21	10:05	582 Ross River	RSM00117	Loss of Supply - Yukon Energy	218	0.02
2010-05-22	7:40	571 Whitehorse	RSM00118	Foreign Interference	1	4.50
2010-05-23	9:30	572 Haines Junction	THB00227	Trees	1	2.47
2010-05-25	16:50	592 Marsh Lake	THB00222	Trees	1	-

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2010-05-25	19:30	571 Whitehorse	RSM00120	Trees	1	1.93
2010-05-26	19:15	571 Whitehorse	DRR00201	Foreign Interference	4	0.50
2010-05-28	16:15	571 Whitehorse	DRR00202	Unknown/Other	2	1.25
2010-05-29	21:15	571 Whitehorse	DRR00207A	Foreign Interference	6	1.00
2010-05-30	14:30	571 Whitehorse	DRR00207	Lightning	2	3.75
2010-05-30	14:30	571 Whitehorse	DRR00210	Lightning	3	3.67
2010-05-30	14:30	571 Whitehorse	DRR00206	Lightning	1	6.50
2010-05-30	14:30	571 Whitehorse	DRR00205	Lightning	1	5.50
2010-05-30	14:30	571 Whitehorse	DRR00204	Lightning	1	4.50
2010-05-30	14:30	571 Whitehorse	DRR00203	Lightning	2	3.75
2010-05-30	14:54	575 Carmacks	PTM0011	Loss of Supply - Yukon Energy	291	0.10
2010-05-30	14:30	571 Whitehorse	DRR00208	Lightning	1	3.33
2010-05-30	14:54	583 Pelly Crossing	PTM00102	Loss of Supply - Yukon Energy	177	0.55
2010-05-30	15:30	582 Ross River	PTM00100	Loss of Supply - Yukon Energy	218	0.05
2010-05-30	14:30	571 Whitehorse	DRR00211	Foreign Interference	1	7.00
2010-05-30	15:29	583 Pelly Crossing	PTM00103	Loss of Supply - Yukon Energy	177	0.48
2010-05-30	14:30	592 Marsh Lake	RSM00122	Trees	25	6.50
2010-05-30	14:30	571 Whitehorse	DRR00209	Lightning	1	3.50
2010-05-30	15:00	571 Whitehorse	RSM00121	Trees	25	2.88
2010-05-30	14:30	592 Marsh Lake	SS00230	Trees	3	5.33
2010-05-31	17:15	592 Marsh Lake	RJZ00231	Trees	1	1.53
2010-06-01	15:00	592 Marsh Lake	RJZ00232	Trees	2	2.17
2010-06-02	15:00	571 Whitehorse	SMB00008	Trees	20	2.25
2010-06-02	15:07	571 Whitehorse	RSM00124	Trees	20	2.30
2010-06-02	20:30	592 Marsh Lake	RSM00123	Foreign Interference	1	1.58
2010-06-02	16:07	578 Beaver Creek	PTM00104	Trees	60	3.32
2010-06-04	12:40	592 Marsh Lake	SS00231	Trees	6	0.25
2010-06-07	10:07	571 Whitehorse	WAF100607-571	Loss of Supply - Yukon Energy	4,882	0.31
2010-06-07	13:15	592 Marsh Lake	RSM00126	Defective Equipment	536	1.00
2010-06-07	15:37	585 Tagish	RJZ00234	Trees	5	2.38
2010-06-07	18:00	583 Pelly Crossing	SS00228	Defective Equipment	1	3.75
2010-06-07	10:07	575 Carmacks	WAF100607-575	Loss of Supply - Yukon Energy	291	0.10
2010-06-07	10:07	583 Pelly Crossing	WAF100607-583	Loss of Supply - Yukon Energy	177	0.38
2010-06-08	14:00	571 Whitehorse	RTW00184-1	Foreign Interference	1	4.83
2010-06-08	11:30	592 Marsh Lake	SS00232	Trees	1	3.00
2010-06-09	17:05	578 Beaver Creek	TGG00188	Trees	73	0.62
2010-06-10	20:50	573 Watson Lake	BRR00097	Lightning	1	0.33
2010-06-11	10:30	571 Whitehorse	RSM00127	Human Element	20	3.50
2010-06-11	18:40	571 Whitehorse	SS00235	Trees	7	0.58
2010-06-12	20:00	573 Watson Lake	BRR00098	Trees	27	0.50
2010-06-12	13:45	574 Carcross	THB00224	Trees	832	1.50
2010-06-12	13:05	572 Haines Junction	TGG00189-1	Foreign Interference	1	4.08
2010-06-12	22:10	573 Watson Lake	BRR00099	Lightning	1	0.47
2010-06-13	10:42	592 Marsh Lake	THB00225	Trees	1	2.80
2010-06-13	12:34	573 Watson Lake	BRR00100	Unknown/Other	2	0.40
2010-06-14	13:30	575 Carmacks	RTW00186	Unknown/Other	13	1.33
2010-06-14	9:10	595 Minto	RTW00185	Foreign Interference	1	4.00
2010-06-16	13:00	573 Watson Lake	BAC00055	Foreign Interference	1	0.42
2010-06-17	1:35	573 Watson Lake	BAC00056	Adverse Environment	3	13.92
2010-06-18	6:30	572 Haines Junction	TGG00190-1	Foreign Interference	1	1.33
2010-06-21	21:10	576 Teslin	RSM00128	Lightning	125	2.33
2010-06-22	14:15	575 Carmacks	SS00234	Unknown/Other	13	0.58
2010-06-22	16:35	571 Whitehorse	RSM00129	Trees	2	1.25
2010-06-23	9:05	580 Keno City	RSM00131	Loss of Supply - Yukon Energy	55	0.37
2010-06-26	14:14	582 Ross River	DRR00212	Unknown/Other	218	0.08
2010-06-27	7:00	571 Whitehorse	DJC00037	Unknown/Other	44	2.00
2010-06-27	7:00	571 Whitehorse	DJC00036	Foreign Interference	5	1.00
2010-06-28	9:30	571 Whitehorse	RSM00132	Unknown/Other	1	1.28
2010-06-28	7:30	574 Carcross	DJC00038	Foreign Interference	5	1.12
2010-06-29	10:15	592 Marsh Lake	RSM00133	Trees	30	1.50
2010-06-30	13:00	571 Whitehorse	RSM00134	Unknown/Other	5	0.25
2010-06-30	17:00	583 Pelly Crossing	BSP00181	Lightning	5	5.00
2010-07-05	6:22	573 Watson Lake	BRR00102	Unknown/Other	1	1.42
2010-07-05	11:30	583 Pelly Crossing	BSP00184	Lightning	1	7.50

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2010-07-06	17:40	585 Tagish	RSM00135	Trees	150	1.00
2010-07-06	19:40	592 Marsh Lake	RSM00136	Trees	10	1.42
2010-07-06	10:20	571 Whitehorse	AMI00101	Trees	1	3.17
2010-07-07	6:30	592 Marsh Lake	BSP00185	Defective Equipment	2	0.83
2010-07-07	18:23	574 Carcross	BSP00186	Trees	621	0.45
2010-07-07	11:40	573 Watson Lake	BRR00103	Unknown/Other	26	0.96
2010-07-09	7:00	571 Whitehorse	RJZ00236	Foreign Interference	2	0.75
2010-07-09	21:45	575 Carmacks	SS00238	Foreign Interference	27	3.08
2010-07-10	14:00	571 Whitehorse	RJZ00237	Trees	20	4.00
2010-07-10	11:30	582 Ross River	SS00236	Foreign Interference	1	0.67
2010-07-11	20:45	590 Lower Post	BRR00105	Foreign Interference	1	4.50
2010-07-12	19:40	576 Teslin	SS00341	Foreign Interference	1	3.00
2010-07-12	18:15	592 Marsh Lake	SS00340	Trees	2	2.25
2010-07-12	7:15	582 Ross River	SS00342	Trees	218	16.00
2010-07-12	10:20	572 Haines Junction	TGG00192	Foreign Interference	1	0.33
2010-07-12	20:10	572 Haines Junction	TGG00192-1	Foreign Interference	1	14.50
2010-07-14	0:00	583 Pelly Crossing	SS00342A	Defective Equipment	2	22.50
2010-07-14	20:30	571 Whitehorse	RJZ00239	Foreign Interference	8	1.00
2010-07-14	8:30	571 Whitehorse	AMI00102	Foreign Interference	6	3.00
2010-07-14	8:43	573 Watson Lake	BRR00107	Foreign Interference	6	0.48
2010-07-21	9:20	576 Teslin	RJZ000240	Foreign Interference	1	0.42
2010-07-21	18:36	590 Lower Post	BAC00072	Scheduled	60	0.10
2010-07-22	16:17	573 Watson Lake	BAC00075	Foreign Interference	4	0.47
2010-07-24	16:40	590 Lower Post	BAC00084	Trees	40	2.00
2010-07-25	16:25	573 Watson Lake	BAC00075-1	Foreign Interference	4	0.33
2010-07-27	10:01	579 Old Crow	RAF00016	Scheduled	181	0.03
2010-07-27	23:58	583 Pelly Crossing	WAF100727-583	Loss of Supply - Yukon Energy	177	1.12
2010-07-27	12:10	594 Deep Creek	RTW00187	Unknown/Other	45	1.58
2010-07-27	11:00	571 Whitehorse	SS00344	Unknown/Other	9	0.50
2010-07-27	23:58	594 Deep Creek	WAF100727-594	Loss of Supply - Yukon Energy	45	1.07
2010-07-27	23:58	575 Carmacks	WAF100727-575	Loss of Supply - Yukon Energy	291	0.12
2010-07-27	23:58	571 Whitehorse	WAF100727-571	Loss of Supply - Yukon Energy	4,149	0.37
2010-07-27	23:58	582 Ross River	WAF100727-582	Loss of Supply - Yukon Energy	218	0.12
2010-07-28	10:00	575 Carmacks	RSM00138	Unknown/Other	30	0.50
2010-07-28	0:30	571 Whitehorse	DJC00039	Unknown/Other	2	2.00
2010-07-28	13:00	571 Whitehorse	RSM00137	Unknown/Other	4	1.33
2010-07-28	12:00	571 Whitehorse	DJC00040	Defective Equipment	2	5.25
2010-07-28	7:00	571 Whitehorse	DRR00215	Foreign Interference	2	0.67
2010-07-29	16:30	592 Marsh Lake	SS00345	Trees	30	0.58
2010-07-30	18:05	571 Whitehorse	WAF100730-571	Loss of Supply - Yukon Energy	4,882	0.50
2010-07-30	18:05	575 Carmacks	WAF100730-575	Loss of Supply - Yukon Energy	291	-
2010-07-30	0:01	571 Whitehorse	RTW00188	Foreign Interference	2	5.07
2010-07-30	18:05	583 Pelly Crossing	WAF100730-583	Loss of Supply - Yukon Energy	177	0.93
2010-07-31	8:00	571 Whitehorse	RTW00190	Unknown/Other	1	7.53
2010-08-01	10:50	571 Whitehorse	RTW00191	Foreign Interference	1	0.67
2010-08-02	10:25	572 Haines Junction	TGG00193	Unknown/Other	194	0.25
2010-08-04	12:30	579 Old Crow	RAF00018	Unknown/Other	181	0.08
2010-08-04	11:31	579 Old Crow	RAF00017	Unknown/Other	181	0.07
2010-08-04	12:11	579 Old Crow	RAF0022-1	Unknown/Other	181	0.03
2010-08-05	11:45	571 Whitehorse	RJZ00241	Unknown/Other	7	0.92
2010-08-07	8:45	573 Watson Lake	BRR00114	Foreign Interference	1	0.42
2010-08-07	8:20	571 Whitehorse	DRR00216	Foreign Interference	30	0.92
2010-08-08	20:30	576 Teslin	DRR00217	Unknown/Other	339	0.19
2010-08-08	19:05	576 Teslin	RTW00192	Unknown/Other	1	17.50
2010-08-08	13:10	572 Haines Junction	TGG00194	Trees	1	1.00
2010-08-10	12:09	579 Old Crow	RAF00021	Unknown/Other	181	0.05
2010-08-10	10:30	571 Whitehorse	RTW00193	Foreign Interference	1	1.17
2010-08-11	19:18	572 Haines Junction	TGG00195	Foreign Interference	1	1.78
2010-08-16	1:41	571 Whitehorse	AMI00103	Foreign Interference	2	2.23
2010-08-17	21:10	571 Whitehorse	AMI00104	Trees	4	0.75
2010-08-17	12:05	579 Old Crow	RAF00019	Unknown/Other	181	0.03
2010-08-18	13:10	573 Watson Lake	BAC00103	Unknown/Other	1	0.83
2010-08-18	13:10	572 Haines Junction	WAF100818-572	Loss of Supply - Yukon Energy	441	0.08
2010-08-18	13:10	582 Ross River	WAF100818-582	Loss of Supply - Yukon Energy	218	0.08

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2010-08-18	13:10	571 Whitehorse	WAF100818-571	Loss of Supply - Yukon Energy	10,780	1.08
2010-08-18	8:30	572 Haines Junction	TGG00196	Unknown/Other	1	1.50
2010-08-18	13:10	575 Carmacks	WAF100818-575	Loss of Supply - Yukon Energy	291	0.08
2010-08-18	13:10	576 Teslin	WAF100818-576	Loss of Supply - Yukon Energy	341	0.41
2010-08-18	13:10	583 Pelly Crossing	WAF100818-583	Loss of Supply - Yukon Energy	177	0.08
2010-08-18	13:10	585 Tagish	WAF100818-585	Loss of Supply - Yukon Energy	371	1.30
2010-08-18	13:10	592 Marsh Lake	WAF100818-592	Loss of Supply - Yukon Energy	447	1.30
2010-08-18	13:10	594 Deep Creek	WAF100818-594	Loss of Supply - Yukon Energy	45	1.33
2010-08-18	13:10	574 Carcross	WAF100818-574	Loss of Supply - Yukon Energy	303	1.30
2010-08-19	12:11	579 Old Crow	RAF00020	Unknown/Other	181	0.03
2010-08-22	11:55	573 Watson Lake	BRR00116	Foreign Interference	1	2.37
2010-08-24	13:10	571 Whitehorse	RTW00194	Foreign Interference	10	0.58
2010-08-24	0:52	579 Old Crow	RAF00022	Unknown/Other	181	0.03
2010-08-25	8:10	590 Lower Post	BAC00104	Unknown/Other	30	0.50
2010-08-25	9:00	571 Whitehorse	RSM00139	Unknown/Other	523	0.62
2010-08-27	18:05	573 Watson Lake	BAC00105	Defective Equipment	25	1.42
2010-08-29	18:30	571 Whitehorse	RTW00196	Foreign Interference	2	0.88
2010-08-30	9:50	571 Whitehorse	RSM00140	Defective Equipment	1	0.63
2010-09-03	16:10	581 Stewart Crossing	RSM00141	Foreign Interference	4	6.83
2010-09-04	10:00	571 Whitehorse	DJC00042	Foreign Interference	1	1.67
2010-09-07	18:00	571 Whitehorse	RSM00142	Foreign Interference	3	1.50
2010-09-07	0:11	591 Upper Liard	SS00346	Unknown/Other	1	9.48
2010-09-07	16:00	575 Carmacks	DJC00044	Foreign Interference	1	2.92
2010-09-08	16:46	579 Old Crow	PTM00106	Loss of Supply - Yukon Electrical	189	0.07
2010-09-13	8:00	576 Teslin	RTW00198	Foreign Interference	1	4.38
2010-09-18	15:00	590 Lower Post	BAC00106	Unknown/Other	1	0.67
2010-09-18	10:29	571 Whitehorse	AMI00105	Foreign Interference	703	3.72
2010-09-20	6:00	583 Pelly Crossing	ELB00003	Defective Equipment	2	7.92
2010-09-20	18:05	573 Watson Lake	BAC00107	Human Element	45	2.67
2010-09-20	9:00	583 Pelly Crossing	ELB00013	Defective Equipment	1	4.92
2010-10-01	15:03	572 Haines Junction	TGG00203	Foreign Interference	1	45.45
2010-10-02	15:30	585 Tagish	THB00234	Trees	1	95.50
2010-10-05	12:00	572 Haines Junction	TGG00205	Unknown/Other	1	3.50
2010-10-06	13:40	571 Whitehorse	RSM00143	Unknown/Other	3	0.92
2010-10-06	3:00	574 Carcross	SS00352	Foreign Interference	1	7.00
2010-10-06	16:30	571 Whitehorse	ELB00012	Foreign Interference	1	0.33
2010-10-07	20:57	576 Teslin	SS000348	Foreign Interference	5	41.30
2010-10-09	12:30	571 Whitehorse	SS000349	Adverse Weather	100	1.25
2010-10-10	9:10	571 Whitehorse	SS000350	Adverse Weather	56	0.67
2010-10-11	11:45	571 Whitehorse	SS000357	Foreign Interference	4	0.55
2010-10-14	17:30	571 Whitehorse	RTW00201	Defective Equipment	16	1.00
2010-10-18	15:30	571 Whitehorse	RSM00144	Foreign Interference	5	0.88
2010-10-19	15:58	572 Haines Junction	TGG00206	Human Element	194	0.15
2010-10-19	16:30	571 Whitehorse	ELB00011	Human Element	1	1.00
2010-10-21	14:40	590 Lower Post	BAC00109	Foreign Interference	1	1.67
2010-10-26	22:15	571 Whitehorse	DRR00221	Defective Equipment	1	0.50
2010-10-26	11:20	571 Whitehorse	RTW00202	Foreign Interference	4	0.55
2010-10-26	16:05	571 Whitehorse	RTW00203	Defective Equipment	4	2.00
2010-10-30	8:00	574 Carcross	BSP00187	Adverse Weather	1	2.25
2010-11-02	9:00	575 Carmacks	ELB00010	Defective Equipment	1	3.50
2010-11-03	21:00	573 Watson Lake	BAC00110	Trees	1	2.50
2010-11-03	20:50	571 Whitehorse	DJC00045	Trees	50	1.42
2010-11-04	10:30	571 Whitehorse	RJZ00248	Trees	1	5.50
2010-11-04	7:56	579 Old Crow	PTM00107	Loss of Supply - Yukon Electrical	189	0.02
2010-11-04	1:20	580 Keno City	DRR00222	Adverse Weather	56	9.08
2010-11-04	16:50	573 Watson Lake	BAC00111	Trees	10	0.67
2010-11-05	11:00	574 Carcross	ELB00009	Trees	1	3.00
2010-11-06	19:50	571 Whitehorse	AMI00106	Scheduled	10	0.50
2010-11-08	21:12	579 Old Crow	PTM00108	Loss of Supply - Yukon Electrical	189	0.07
2010-11-09	16:00	571 Whitehorse	SMB00010	Defective Equipment	1	0.50
2010-11-17	16:05	571 Whitehorse	RTW00204	Foreign Interference	2	0.50
2010-11-19	0:16	571 Whitehorse	THB00238	Foreign Interference	24	0.82
2010-11-22	8:55	571 Whitehorse	RJZ00249	Defective Equipment	2	1.08
2010-11-24	10:30	571 Whitehorse	ELB00008	Defective Equipment	10	1.83

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2010-11-24	7:17	580 Keno City	THB00239	Loss of Supply - Yukon Energy	56	0.33
2010-11-24	10:15	571 Whitehorse	SMB00011	Defective Equipment	21	1.39
2010-11-26	21:20	580 Keno City	AMI00107	Loss of Supply - Yukon Energy	55	-
2010-11-29	19:05	571 Whitehorse	WAF101129-571	Loss of Supply - Yukon Energy	2,973	0.22
2010-11-29	19:05	576 Teslin	WAF101129-576	Loss of Supply - Yukon Energy	351	0.17
2010-11-29	19:05	583 Pelly Crossing	WAF101129-583	Loss of Supply - Yukon Energy	180	0.50
2010-11-29	19:05	585 Tagish	WAF101129-585	Loss of Supply - Yukon Energy	373	0.17
2010-11-29	19:05	592 Marsh Lake	WAF101129-592	Loss of Supply - Yukon Energy	458	0.17
2010-11-29	19:05	574 Carcross	WAF101129-574	Loss of Supply - Yukon Energy	317	0.17
2010-11-29	19:05	575 Carmacks	WAF101129-575	Loss of Supply - Yukon Energy	289	0.28
2010-11-30	9:00	574 Carcross	SS000353	Defective Equipment	8	3.00
2010-12-01	13:00	571 Whitehorse	ELB00007	Defective Equipment	1	1.67
2010-12-03	1:35	579 Old Crow	PTM00110	Loss of Supply - Yukon Electrical	567	0.06
2010-12-05	11:37	571 Whitehorse	DRR00224	Foreign Interference	1	3.38
2010-12-08	10:06	573 Watson Lake	JES00087	Loss of Supply - Yukon Electrical	424	0.05
2010-12-08	14:29	581 Stewart Crossing	DRR00225	Loss of Supply - Yukon Energy	31	0.68
2010-12-08	10:06	590 Lower Post	JES00088	Loss of Supply - Yukon Electrical	91	0.05
2010-12-08	10:06	591 Upper Liard	JES00089	Loss of Supply - Yukon Electrical	116	0.05
2010-12-10	10:55	571 Whitehorse	RSM00145	Human Element	308	0.28
2010-12-15	12:53	571 Whitehorse	SMB00012	Foreign Interference	1	1.67
2010-12-15	20:15	571 Whitehorse	SS000354	Defective Equipment	11	4.00
2010-12-16	5:17	579 Old Crow	PTM00109	Loss of Supply - Yukon Electrical	189	0.35
2010-12-18	14:00	571 Whitehorse	BSP00189	Foreign Interference	6	0.50
2010-12-18	17:30	571 Whitehorse	THB00240	Unknown/Other	2	1.00
2010-12-20	22:30	576 Teslin	THB00241	Unknown/Other	1	2.00
2010-12-20	9:01	571 Whitehorse	DJC00046	Defective Equipment	249	0.52
2010-12-22	13:39	581 Stewart Crossing	DRR00227	Loss of Supply - Yukon Energy	31	0.08
2010-12-23	0:30	590 Lower Post	BAC00112	Adverse Weather	85	4.50
2010-12-24	14:30	571 Whitehorse	DJC00048	Foreign Interference	20	2.00
2010-12-24	20:00	571 Whitehorse	DJC00049	Foreign Interference	1	0.83
2010-12-24	14:20	571 Whitehorse	DJC00047	Foreign Interference	12	1.67
2010-12-27	13:49	571 Whitehorse	DJC00050	Foreign Interference	1	5.02
2010-12-27	16:30	573 Watson Lake	BAC00113	Loss of Supply - Yukon Electrical	1,000	0.25
2010-12-28	12:30	571 Whitehorse	GLP00009	Foreign Interference	1	1.23
2011-01-02	20:36	585 Tagish	BSP00191	Adverse Weather	1	1.43
2011-01-03	17:20	580 Keno City	BSP00192	Loss of Supply - Yukon Energy	56	0.10
2011-01-06	4:00	573 Watson Lake	BAC00114	Adverse Weather	1	1.50
2011-01-06	13:30	583 Pelly Crossing	ELB00004	Foreign Interference	1	0.50
2011-01-07	12:00	591 Upper Liard	BAC00115	Trees	13	1.50
2011-01-09	16:45	592 Marsh Lake	RSM00146	Foreign Interference	50	1.00
2011-01-10	21:00	571 Whitehorse	RSM00147	Adverse Weather	3	0.92
2011-01-11	16:15	575 Carmacks	RSM00148	Adverse Weather	4	3.92
2011-01-12	11:35	571 Whitehorse	RTW00205	Foreign Interference	1	0.83
2011-01-14	1:30	576 Teslin	AMI00111	Defective Equipment	2	13.50
2011-01-16	15:00	592 Marsh Lake	ELB00005	Adverse Weather	15	1.75
2011-01-18	15:00	576 Teslin	ELB00006	Adverse Weather	1	2.00
2011-01-19	21:30	571 Whitehorse	ELB00013A	Adverse Weather	10	0.75
2011-01-20	13:00	585 Tagish	DJC00047A	Adverse Weather	1	3.33
2011-01-20	13:35	573 Watson Lake	BSP00193	Trees	1	0.92
2011-01-21	19:00	571 Whitehorse	DJC00043	Defective Equipment	1	15.83
2011-01-22	13:17	573 Watson Lake	JES00090	Loss of Supply - Yukon Electrical	956	0.30
2011-01-22	14:30	571 Whitehorse	THB00244	Adverse Weather	5	0.75
2011-01-22	14:05	571 Whitehorse	DRR00230	Adverse Weather	35	0.42
2011-01-22	13:17	591 Upper Liard	JES00092	Loss of Supply - Yukon Electrical	116	0.33
2011-01-22	16:00	590 Lower Post	RTW00205A	Adverse Weather	56	2.66
2011-01-22	13:17	590 Lower Post	JES00091	Loss of Supply - Yukon Electrical	91	0.30
2011-01-23	14:15	573 Watson Lake	RTW00207	Foreign Interference	1	1.00
2011-01-23	2:13	575 Carmacks	WAF110123-575	Loss of Supply - Yukon Energy	289	0.03
2011-01-23	2:13	571 Whitehorse	WAF110123-571	Loss of Supply - Yukon Energy	1,967	0.20
2011-01-23	2:13	583 Pelly Crossing	WAF110123-583	Loss of Supply - Yukon Energy	180	0.85
2011-01-23	9:40	590 Lower Post	RTW00206	Adverse Weather	2	1.00
2011-01-23	2:13	582 Ross River	WAF110123-582	Loss of Supply - Yukon Energy	218	0.03
2011-01-23	2:13	594 Deep Creek	WAF110123-594	Loss of Supply - Yukon Energy	45	0.62
2011-01-24	10:40	573 Watson Lake	RTW00208	Unknown/Other	1	0.17

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2011-01-24	5:40	580 Keno City	DRR00234	Loss of Supply - Yukon Energy	56	0.23
2011-01-29	15:01	580 Keno City	SS000306	Loss of Supply - Yukon Energy	59	0.07
2011-01-31	13:40	571 Whitehorse	SMB00014	Foreign Interference	1	0.33
2011-02-01	18:25	571 Whitehorse	SS000307	Human Element	1	0.08
2011-02-01	13:00	592 Marsh Lake	RTW00210	Adverse Weather	4	1.25
2011-02-03	1:10	576 Teslin	SS000309	Trees	97	4.77
2011-02-03	1:15	576 Teslin	SS000310	Trees	262	0.08
2011-02-04	11:28	583 Pelly Crossing	WAF110204-583	Unknown/Other	180	0.48
2011-02-04	11:28	575 Carmacks	WAF110204-575	Unknown/Other	289	0.08
2011-02-04	11:28	571 Whitehorse	WAF110204-571	Unknown/Other	2,716	0.80
2011-02-06	15:15	571 Whitehorse	RJZ00250	Foreign Interference	1	0.50
2011-02-13	22:00	571 Whitehorse	SMB00015	Trees	20	2.25
2011-02-26	15:30	575 Carmacks	SS000313A	Trees	2	4.25
2011-02-26	12:40	592 Marsh Lake	AMI00112	Trees	250	4.83
2011-02-26	8:30	578 Beaver Creek	TGG00220	Trees	118	8.24
2011-02-27	15:00	571 Whitehorse	RTW00213	Trees	70	2.58
2011-02-27	15:00	576 Teslin	RTW00212	Trees	353	0.80
2011-02-27	15:00	592 Marsh Lake	RTW00211	Trees	455	2.83
2011-02-27	18:30	571 Whitehorse	DJC00050A	Foreign Interference	1	19.33
2011-03-10	5:15	582 Ross River	BSP00195	Adverse Environment	1	-
2011-03-14	3:30	571 Whitehorse	RSM00149		10	2.67
2011-03-16	16:00	571 Whitehorse	RSM00150	Unknown/Other	1	1.67
2011-03-17	16:40	573 Watson Lake	BAC00116	Defective Equipment	1	1.08
2011-03-18	21:27	571 Whitehorse	RJZ00252	Defective Equipment	1	0.63
2011-03-19	13:15	571 Whitehorse	RJZ00253	Foreign Interference	35	0.75
2011-03-19	18:00	576 Teslin	AMI00115	Defective Equipment	6	2.25
2011-03-21	14:00	576 Teslin	RJZ00254	Defective Equipment	41	4.25
2011-03-22	14:25	571 Whitehorse	WAF110322-571	Loss of Supply - Yukon Energy	11,584	1.55
2011-03-22	14:25	574 Carcross	WAF110322-574	Loss of Supply - Yukon Energy	317	1.23
2011-03-22	14:25	575 Carmacks	WAF110322-575	Loss of Supply - Yukon Energy	289	0.08
2011-03-22	14:25	576 Teslin	WAF110322-576	Loss of Supply - Yukon Energy	351	0.29
2011-03-22	14:25	582 Ross River	WAF110322-582	Loss of Supply - Yukon Energy	218	0.08
2011-03-22	14:25	583 Pelly Crossing	WAF110322-583	Loss of Supply - Yukon Energy	180	0.67
2011-03-22	14:25	585 Tagish	WAF110322-585	Loss of Supply - Yukon Energy	373	1.17
2011-03-22	14:25	592 Marsh Lake	WAF110322-592	Loss of Supply - Yukon Energy	458	0.95
2011-03-22	14:25	594 Deep Creek	WAF110322-594	Loss of Supply - Yukon Energy	45	2.22
2011-03-22	14:25	572 Haines Junction	WAF110322-572	Loss of Supply - Yukon Energy	495	0.08
2011-03-25	10:55	571 Whitehorse	SS000316	Foreign Interference	1	0.82
2011-03-27	15:00	576 Teslin	ELB00014	Foreign Interference	6	4.50
2011-03-27	14:15	571 Whitehorse	SS000314	Defective Equipment	788	0.94
2011-03-28	16:00	574 Carcross	BSP00196	Foreign Interference	1	1.50
2011-03-29	10:30	571 Whitehorse	ELB00015	Foreign Interference	10	1.50
2011-03-31	10:30	582 Ross River	RTW00216	Foreign Interference	2	6.92
2011-04-06	14:30	573 Watson Lake	RGG00002	Unknown/Other	3	0.33
2011-04-07	12:15	591 Upper Liard	BAC00117	Unknown/Other	5	0.50
2011-04-08	12:30	573 Watson Lake	RGG00003	Unknown/Other	1	0.92
2011-04-08	14:40	591 Upper Liard	RGG00004	Defective Equipment	5	1.00
2011-04-11	11:00	574 Carcross	RSM00151	Foreign Interference	1	1.50
2011-04-12	8:44	571 Whitehorse	RJZ00257	Foreign Interference	1	0.27
2011-04-12	16:45	573 Watson Lake	RGG00005	Unknown/Other	1	4.50
2011-04-14	22:40	571 Whitehorse	SMB00017A	Defective Equipment	2	1.08
2011-04-16	9:20	571 Whitehorse	AMI00116	Foreign Interference	17	0.80
2011-04-16	13:30	571 Whitehorse	AMI00117	Human Element	1	0.33
2011-04-17	11:30	592 Marsh Lake	SMB00018	Foreign Interference	1	4.75
2011-04-21	22:30	571 Whitehorse	RSM00152	Trees	20	2.33
2011-04-25	9:31	571 Whitehorse	SS000335	Foreign Interference	1,929	0.70
2011-04-29	11:30	571 Whitehorse	RSM00153	Foreign Interference	10	1.00
2011-05-02	15:30	571 Whitehorse	SMB00019	Defective Equipment	34	1.33
2011-05-09	12:00	592 Marsh Lake	WAF110509-592	Loss of Supply - Yukon Energy	458	1.82
2011-05-09	12:00	572 Haines Junction	WAF110509-572	Loss of Supply - Yukon Energy	495	1.47
2011-05-09	12:00	574 Carcross	WAF110509-574	Loss of Supply - Yukon Energy	317	1.82
2011-05-09	12:00	571 Whitehorse	WAF110509-571	Loss of Supply - Yukon Energy	11,584	1.45
2011-05-09	12:00	576 Teslin	WAF110509-576	Loss of Supply - Yukon Energy	351	0.49
2011-05-09	12:00	585 Tagish	WAF110509-585	Loss of Supply - Yukon Energy	373	1.80

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2011-05-09	12:00	583 Pelly Crossing	WAF110509-583	Loss of Supply - Yukon Energy	180	0.37
2011-05-09	12:00	582 Ross River	WAF110509-582	Loss of Supply - Yukon Energy	218	0.03
2011-05-09	12:00	575 Carmacks	WAF110509-575	Loss of Supply - Yukon Energy	289	0.03
2011-05-09	12:00	594 Deep Creek	WAF110509-594	Loss of Supply - Yukon Energy	45	1.57
2011-05-10	12:20	571 Whitehorse	DRR00237	Foreign Interference	1	0.50
2011-05-11	10:35	574 Carcross	RJZ00261A	Defective Equipment	317	4.58
2011-05-11	10:35	585 Tagish	RJZ00261B	Defective Equipment	377	4.58
2011-05-12	8:15	591 Upper Liard	RGG00009	Adverse Weather	25	2.17
2011-05-12	18:33	573 Watson Lake	BAC00118	Unknown/Other	210	0.78
2011-05-13	17:20	573 Watson Lake	RGG00010	Defective Equipment	1	4.37
2011-05-15	15:50	571 Whitehorse	BSP00197	Foreign Interference	1	1.58
2011-05-16	11:00	571 Whitehorse	SMB00020	Foreign Interference	5	0.58
2011-05-17	9:40	571 Whitehorse	SMB00021	Defective Equipment	3	2.67
2011-05-18	3:00	571 Whitehorse	BSP00198	Defective Equipment	5	0.50
2011-05-18	16:30	571 Whitehorse	RTW00218	Foreign Interference	1	1.25
2011-05-24	8:50	571 Whitehorse	RTW00219	Foreign Interference	10	1.92
2011-05-29	15:30	573 Watson Lake	BAC00119	Trees	9	1.08
2011-05-30	12:19	583 Pelly Crossing	DRR00241	Foreign Interference	180	1.75
2011-06-01	10:30	571 Whitehorse	SS000336	Foreign Interference	7	0.57
2011-06-02	10:55	571 Whitehorse	RTW00220	Foreign Interference	3	0.42
2011-06-12	23:00	580 Keno City	BSP00199	Defective Equipment	50	8.00
2011-06-15	7:00	571 Whitehorse	SS000338	Foreign Interference	10	1.00
2011-06-15	9:15	571 Whitehorse	RSM00154	Foreign Interference	10	0.83
2011-06-17	12:47	576 Teslin	RJZ00262	Defective Equipment	534	0.20
2011-06-19	1:00	592 Marsh Lake	GLP00010	Defective Equipment	6	1.33
2011-06-19	7:55	572 Haines Junction	DJC00051A	Foreign Interference	1	4.58
2011-06-19	7:00	571 Whitehorse	GLP00012	Defective Equipment	10	3.00
2011-06-20	7:15	572 Haines Junction	RTW00221	Foreign Interference	5	2.92
2011-06-20	9:10	571 Whitehorse	RJZ00263	Foreign Interference	15	0.83
2011-06-21	15:00	573 Watson Lake	RGG00011	Unknown/Other	10	0.53
2011-06-21	9:00	571 Whitehorse	GLP00011	Unknown/Other	1	0.77
2011-06-22	8:05	576 Teslin	RJZ00264	Foreign Interference	1	2.83
2011-06-23	17:10	583 Pelly Crossing	RSM00155	Defective Equipment	70	0.83
2011-06-23	16:00	572 Haines Junction	RTW00222	Foreign Interference	1	2.25
2011-06-24	13:30	582 Ross River	SS000339	Defective Equipment	2	25.58
2011-06-26	16:38	581 Stewart Crossing	RJZ00265	Defective Equipment	70	5.40
2011-06-26	15:50	581 Stewart Crossing	AMI00119	Loss of Supply - Yukon Energy	32	4.67
2011-06-26	8:00	571 Whitehorse	AMI00118	Foreign Interference	12	1.75
2011-06-27	17:26	591 Upper Liard	JES00094	Lightning	752	0.20
2011-06-27	7:00	571 Whitehorse	RSM00156	Unknown/Other	5	1.25
2011-06-27	16:05	571 Whitehorse	THB00252-571	Loss of Supply - Yukon Energy	1,302	0.27
2011-06-27	17:26	573 Watson Lake	JES00093	Lightning	752	0.20
2011-06-27	17:26	590 Lower Post	JES00095	Lightning	91	0.20
2011-06-27	16:05	581 Stewart Crossing	THB00252	Loss of Supply - Yukon Energy	35	0.08
2011-06-28	21:49	580 Keno City	DRR00240	Loss of Supply - Yukon Energy	56	0.40
2011-06-28	10:35	571 Whitehorse	RSM00157	Human Element	100	2.08
2011-06-28	13:22	581 Stewart Crossing	DRR00239	Loss of Supply - Yukon Energy	62	1.41
2011-07-01	8:00	572 Haines Junction	DJC00052	Foreign Interference	1	9.50
2011-07-01	18:30	571 Whitehorse	RSM00159	Foreign Interference	50	0.75
2011-07-01	11:30	571 Whitehorse	RSM00158	Human Element	585	0.85
2011-07-02	20:12	571 Whitehorse	DJC00053	Foreign Interference	1	1.53
2011-07-02	19:30	571 Whitehorse	RSM00160	Foreign Interference	20	2.25
2011-07-04	10:50	582 Ross River	DJC00054	Defective Equipment	3	17.17
2011-07-06	20:15	592 Marsh Lake	WAF110706-592	Loss of Supply - Yukon Energy	458	0.97
2011-07-06	16:52	582 Ross River	DJC00055	Foreign Interference	2	22.97
2011-07-06	20:15	576 Teslin	WAF110706-576	Loss of Supply - Yukon Energy	351	0.33
2011-07-06	20:15	585 Tagish	WAF110706-585	Loss of Supply - Yukon Energy	373	0.97
2011-07-06	20:15	594 Deep Creek	WAF110706-594	Loss of Supply - Yukon Energy	45	1.58
2011-07-06	20:15	582 Ross River	WAF110706-582	Loss of Supply - Yukon Energy	218	0.08
2011-07-06	20:15	571 Whitehorse	WAF110706-571	Loss of Supply - Yukon Energy	11,584	1.22
2011-07-06	20:15	574 Carcross	WAF110706-574	Loss of Supply - Yukon Energy	317	0.97
2011-07-06	20:15	575 Carmacks	WAF110706-575	Loss of Supply - Yukon Energy	289	1.58
2011-07-07	20:00	576 Teslin	SS000340	Foreign Interference	6	2.67
2011-07-07	13:45	571 Whitehorse	DRR00243	Foreign Interference	4,679	0.46

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2011-07-07	23:30	571 Whitehorse	SMB00023	Defective Equipment	20	0.87
2011-07-07	7:40	573 Watson Lake	RGG00012	Foreign Interference	2	0.37
2011-07-08	17:25	571 Whitehorse	DRR00244	Lightning	46	0.38
2011-07-10	17:00	576 Teslin	SS000342	Foreign Interference	1	2.50
2011-07-11	9:00	571 Whitehorse	RJZ00266	Foreign Interference	1	0.73
2011-07-13	3:00	576 Teslin	AMI00121	Foreign Interference	1	7.50
2011-07-14	6:30	576 Teslin	SS000341	Foreign Interference	1	3.42
2011-07-14	12:05	572 Haines Junction	RTW00223	Defective Equipment	135	1.32
2011-07-15	15:00	590 Lower Post	BSP00203	Foreign Interference	1	1.00
2011-07-15	10:15	576 Teslin	MWG00001	Foreign Interference	1	1.75
2011-07-15	8:00	581 Stewart Crossing	DRR00245	Trees	31	4.50
2011-07-16	1:04	572 Haines Junction	GLP00012A	Defective Equipment	1	2.15
2011-07-17	9:20	571 Whitehorse	RTW00224	Foreign Interference	10	0.67
2011-07-18	14:30	576 Teslin	RJZ00267	Foreign Interference	6	0.28
2011-07-19	3:45	585 Tagish	WAF110719-585	Loss of Supply - Yukon Energy	373	0.75
2011-07-19	3:45	571 Whitehorse	WAF110719-571	Loss of Supply - Yukon Energy	6,471	1.31
2011-07-19	3:45	574 Carcross	WAF110719-574	Loss of Supply - Yukon Energy	317	0.75
2011-07-19	3:45	576 Teslin	WAF110719-576	Loss of Supply - Yukon Energy	351	0.28
2011-07-19	3:45	592 Marsh Lake	WAF110719-592	Loss of Supply - Yukon Energy	458	0.78
2011-07-20	6:30	592 Marsh Lake	GLP00013	Defective Equipment	20	1.47
2011-07-20	13:40	590 Lower Post	RGG00013	Foreign Interference	1	0.68
2011-07-21	6:59	573 Watson Lake	RGG00014	Foreign Interference	1	0.43
2011-07-22	7:10	571 Whitehorse	RJZ00269	Foreign Interference	30	2.14
2011-07-22	16:00	574 Carcross	AMI00122	Defective Equipment	1	3.50
2011-07-23	16:00	576 Teslin	AMI00123	Defective Equipment	1	2.00
2011-07-23	15:45	576 Teslin	AMI00124	Defective Equipment	1	2.75
2011-07-25	8:35	571 Whitehorse	AMI00125	Foreign Interference	9	0.50
2011-07-25	12:15	571 Whitehorse	RJZ00273	Defective Equipment	7	1.00
2011-07-26	4:00	573 Watson Lake	RGG00015	Foreign Interference	6	2.25
2011-07-26	10:30	572 Haines Junction	RJZ00274	Foreign Interference	4	3.33
2011-07-28	9:00	571 Whitehorse	RSM00161	Defective Equipment	30	1.92
2011-07-29	21:25	571 Whitehorse	RSM00163	Unknown/Other	50	1.25
2011-07-31	11:00	575 Carmacks	RSM00164	Loss of Supply - Yukon Energy	292	0.03
2011-07-31	11:00	572 Haines Junction	RSM00163B	Loss of Supply - Yukon Energy	514	0.03
2011-07-31	11:00	583 Pelly Crossing	RSM00164A	Loss of Supply - Yukon Energy	179	0.03
2011-07-31	11:00	581 Stewart Crossing	RSM00164B	Loss of Supply - Yukon Energy	31	0.03
2011-07-31	11:00	582 Ross River	RSM00164C	Loss of Supply - Yukon Energy	219	0.03
2011-08-03	9:00	571 Whitehorse	MWG00002	Unknown/Other	1	1.25
2011-08-04	15:40	571 Whitehorse	SMB00025	Foreign Interference	2	1.02
2011-08-06	11:00	576 Teslin	SS000343	Foreign Interference	1	3.83
2011-08-06	11:00	571 Whitehorse	SS000344	Foreign Interference	3	1.40
2011-08-07	16:09	573 Watson Lake	DJC00056	Trees	1,000	0.48
2011-08-07	15:15	571 Whitehorse	SS000346	Foreign Interference	1	1.17
2011-08-07	9:00	592 Marsh Lake	SS000345	Defective Equipment	2	2.75
2011-08-08	14:00	590 Lower Post	DJC00057	Unknown/Other	1	0.17
2011-08-09	12:04	576 Teslin	SMB00026	Foreign Interference	4	3.65
2011-08-09	17:30	583 Pelly Crossing	SS000347A	Defective Equipment	2	0.50
2011-08-10	17:00	573 Watson Lake	DJC00058	Unknown/Other	1	0.33
2011-08-11	14:30	575 Carmacks	RJZ00275	Trees	35	2.00
2011-08-12	19:00	571 Whitehorse	BSP00205	Defective Equipment	20	2.08
2011-08-12	11:10	571 Whitehorse	RTW00227	Foreign Interference	1	4.67
2011-08-14	12:30	571 Whitehorse	BSP00206	Foreign Interference	1	-
2011-08-14	12:22	573 Watson Lake	SS000349A	Loss of Supply - Yukon Electrical	905	0.30
2011-08-18	17:15	571 Whitehorse	DRR00248	Foreign Interference	2	0.33
2011-08-20	9:30	572 Haines Junction	THB00259	Foreign Interference	1	2.00
2011-08-21	9:30	582 Ross River	THB00260	Adverse Weather	2	5.82
2011-08-23	18:40	590 Lower Post	RGG00016	Foreign Interference	2	0.92
2011-08-23	2:46	579 Old Crow	PTM00111	Loss of Supply - Yukon Electrical	756	0.03
2011-08-24	3:30	571 Whitehorse	RTW00229	Foreign Interference	7	2.75
2011-08-24	14:35	571 Whitehorse	SMB00027	Foreign Interference	1	1.92
2011-08-25	8:35	590 Lower Post	RGG00017	Foreign Interference	1	0.88
2011-08-25	12:00	580 Keno City	RTW00230	Loss of Supply - Yukon Energy	112	7.54
2011-08-29	6:23	573 Watson Lake	RGG00018	Foreign Interference	1	3.13
2011-08-29	14:55	571 Whitehorse	AMI00126	Foreign Interference	4	4.42

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2011-08-30	16:30	571 Whitehorse	SS000348A	Defective Equipment	4	3.17
2011-08-31	9:30	573 Watson Lake	RGG00019	Foreign Interference	6	1.08
2011-09-03	11:30	571 Whitehorse	SMB00028	Trees	20	0.67
2011-09-08	18:45	585 Tagish	SS000349B	Trees	5	0.25
2011-09-08	18:00	571 Whitehorse	DJC00059	Trees	1	1.00
2011-09-09	16:40	573 Watson Lake	RGG00020	Trees	40	1.50
2011-09-09	19:21	573 Watson Lake	RGG00021	Trees	510	0.40
2011-09-09	15:15	591 Upper Liard	RGG00022	Trees	25	1.55
2011-09-09	14:20	590 Lower Post	RGG00023	Trees	6	1.02
2011-09-11	11:20	573 Watson Lake	RGG00024	Foreign Interference	1	4.33
2011-09-11	9:50	571 Whitehorse	DJC00060	Foreign Interference	4	0.50
2011-09-13	18:04	583 Pelly Crossing	DJC00061	Adverse Environment	179	0.38
2011-09-18	16:15	571 Whitehorse	THB00263	Foreign Interference	1	0.25
2011-09-19	14:10	573 Watson Lake	BAC00119A	Loss of Supply - Yukon Electrical	150	2.33
2011-09-20	15:45	581 Stewart Crossing	SMB00030	Trees	5	19.75
2011-09-21	13:00	590 Lower Post	BAC00120	Unknown/Other	1	1.25
2011-09-21	18:00	571 Whitehorse	SS000350A	Trees	2	6.13
2011-09-22	13:50	573 Watson Lake	BAC00121	Unknown/Other	1	1.67
2011-09-24	12:55	573 Watson Lake	BAC00122	Foreign Interference	6	0.58
2011-09-29	12:04	581 Stewart Crossing	DRR00251	Loss of Supply - Yukon Energy	31	7.08
2011-09-29	12:04	580 Keno City	DRR00251A	Loss of Supply - Yukon Energy	56	0.68
2011-10-05	10:15	571 Whitehorse	SMB00031	Foreign Interference	5	0.50
2011-10-07	16:00	583 Pelly Crossing	AMI00127	Foreign Interference	48	2.00
2011-10-12	23:18	571 Whitehorse	AMI00128	Foreign Interference	1,105	2.45
2011-10-19	17:40	571 Whitehorse	DRR00255	Defective Equipment	1	0.75
2011-10-25	8:05	590 Lower Post	BAC00123	Foreign Interference	1	0.58
2011-10-29	18:10	571 Whitehorse	DRR00257	Trees	2	0.50
2011-10-30	19:00	571 Whitehorse	MWRG0003	Trees	2	0.50
2011-11-01	13:30	571 Whitehorse	DRR00263	Trees	766	0.58
2011-11-01	15:00	571 Whitehorse	SMB00033	Trees	3	2.33
2011-11-02	19:10	572 Haines Junction	DJC00067	Trees	15	0.48
2011-11-07	18:40	571 Whitehorse	DRR00261	Foreign Interference	2	0.33
2011-11-08	19:00	571 Whitehorse	RSM00165	Foreign Interference	2	0.75
2011-11-10	11:40	585 Tagish	WAF00262-585	Loss of Supply - Yukon Energy	373	0.23
2011-11-10	11:40	576 Teslin	WAF00262-576	Loss of Supply - Yukon Energy	351	0.19
2011-11-10	11:40	592 Marsh Lake	WAF00262-592	Loss of Supply - Yukon Energy	458	0.23
2011-11-10	11:40	571 Whitehorse	WAF00262-571	Loss of Supply - Yukon Energy	6,255	0.48
2011-11-10	11:40	574 Carcross	WAF00262-574	Loss of Supply - Yukon Energy	317	0.23
2011-11-15	7:15	571 Whitehorse	RJZ00278	Adverse Weather	1	1.00
2011-11-15	11:30	573 Watson Lake	BAC00124	Foreign Interference	1	0.33
2011-11-19	18:30	571 Whitehorse	BSP00213	Defective Equipment	300	1.33
2011-11-22	14:30	571 Whitehorse	SS000351	Defective Equipment	9	0.42
2011-11-24	11:30	571 Whitehorse	SS000352	Defective Equipment	7	2.00
2011-11-25	10:45	571 Whitehorse	THB00267	Defective Equipment	1	0.67
2011-12-01	7:35	572 Haines Junction	RTW00238A	Adverse Weather	29	1.00
2011-12-01	16:45	571 Whitehorse	RJZ00281	Defective Equipment	2	0.58
2011-12-01	6:23	572 Haines Junction	THB00265	Adverse Weather	498	0.08
2011-12-04	19:45	572 Haines Junction	RTW00237	Trees	570	1.23
2011-12-04	22:00	571 Whitehorse	MWG00004	Trees	8	3.00
2011-12-04	22:30	572 Haines Junction	RTW00238	Trees	570	2.39
2011-12-04	19:45	572 Haines Junction	RTW00236	Trees	15	0.67
2011-12-04	19:00	571 Whitehorse	MWG00003	Trees	4	2.50
2011-12-05	1:40	572 Haines Junction	RTW00240	Trees	45	0.64
2011-12-05	8:00	571 Whitehorse	RSM00166	Trees	5	3.92
2011-12-05	15:00	571 Whitehorse	RSM00167	Trees	30	0.50
2011-12-05	3:55	574 Carcross	MWG00005	Adverse Weather	20	2.08
2011-12-05	18:00	571 Whitehorse	AMI00129	Trees	10	2.67
2011-12-05	1:10	572 Haines Junction	RTW00239	Trees	560	0.25
2011-12-05	15:50	591 Upper Liard	RGG00027	Trees	105	1.75
2011-12-05	5:30	585 Tagish	MWG00006	Trees	30	19.25
2011-12-06	8:00	585 Tagish	RSM00168	Trees	4	6.58
2011-12-10	12:00	572 Haines Junction	BSP00214	Adverse Weather	1	4.00
2011-12-10	14:00	575 Carmacks	THB00268	Foreign Interference	21	7.17
2011-12-11	12:00	580 Keno City	RSM00170	Adverse Weather	1	28.00

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Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2011-12-12	23:30	571 Whitehorse	RSM00169	Defective Equipment	1	4.00
2011-12-18	17:15	571 Whitehorse	AMI00130	Trees	4	1.25
2011-12-24	17:00	572 Haines Junction	RTW00241	Unknown/Other	2	0.92
2011-12-24	20:15	573 Watson Lake	RAC00126	Defective Equipment	3	0.50
2011-12-28	9:00	572 Haines Junction	RTW00242	Unknown/Other	1	0.25
2012-01-01	23:59	580 Keno City	THB00267A	Loss of Supply - Yukon Energy	56	11.02
2012-01-02	13:00	572 Haines Junction	RTW00244	Adverse Weather	2	1.00
2012-01-03	9:40	572 Haines Junction	RTW00243	Foreign Interference	1	0.40
2012-01-07	13:04	573 Watson Lake	RGG00029	Adverse Weather	329	0.43
2012-01-08	7:45	571 Whitehorse	MWG00008	Adverse Weather	5	1.25
2012-01-09	12:20	591 Upper Liard	RGG00030	Adverse Weather	28	1.97
2012-01-10	12:00	571 Whitehorse	SMB00035	Foreign Interference	3	4.50
2012-01-11	8:30	571 Whitehorse	SMB00036	Defective Equipment	1	1.50
2012-01-12	17:45	571 Whitehorse	DRR00264	Defective Equipment	2	1.00
2012-01-17	21:05	571 Whitehorse	RJZ00282	Defective Equipment	2	0.75
2012-01-17	12:45	571 Whitehorse	DRR00265	Defective Equipment	1,100	2.58
2012-01-18	14:06	582 Ross River	MWG00009	Adverse Weather	1	7.40
2012-01-18	13:20	591 Upper Liard	RGG00031	Defective Equipment	30	0.57
2012-01-18	18:29	571 Whitehorse	DJC00073	Defective Equipment	3,900	2.18
2012-01-18	6:55	579 Old Crow	PTM00112	Loss of Supply - Yukon Electrical	181	0.02
2012-01-20	16:00	571 Whitehorse	DJC00068	Defective Equipment	1	0.87
2012-01-21	13:30	582 Ross River	SMB00037	Defective Equipment	3	7.67
2012-01-22	12:24	590 Lower Post	RGG00032	Foreign Interference	1	0.80
2012-01-22	8:50	571 Whitehorse	SMB00038	Defective Equipment	3	0.50
2012-01-25	9:54	582 Ross River	PTM00114	Loss of Supply - Yukon Energy	218	0.07
2012-01-25	6:01	579 Old Crow	PTM00113	Loss of Supply - Yukon Electrical	189	0.03
2012-01-29	12:59	580 Keno City	SS000356	Loss of Supply - Yukon Energy	56	0.07
2012-02-03	10:00	592 Marsh Lake	DJC00070	Trees	50	3.08
2012-02-03	9:40	592 Marsh Lake	AMI00132	Trees	89	4.33
2012-02-03	18:30	575 Carmacks	MWG00011	Trees	5	5.25
2012-02-03	11:20	571 Whitehorse	RSM00172	Trees	30	2.23
2012-02-03	8:30	585 Tagish	SMB00039	Trees	30	4.00
2012-02-03	9:15	571 Whitehorse	SS000358	Adverse Weather	1,103	0.25
2012-02-03	9:30	592 Marsh Lake	DJC00071	Trees	2	3.50
2012-02-03	12:08	571 Whitehorse	RJZ00283	Trees	102	-
2012-02-04	8:00	579 Old Crow	PTM00115	Defective Equipment	724	0.04
2012-02-05	18:00	571 Whitehorse	DRR00267	Defective Equipment	7	1.33
2012-02-09	15:00	576 Teslin	MWG00012	Trees	1	2.50
2012-02-11	16:30	571 Whitehorse	THB00270	Defective Equipment	3	2.75
2012-02-12	22:00	583 Pelly Crossing	MWG00010	Defective Equipment	40	7.50
2012-02-20	21:30	582 Ross River	AMI00131	Defective Equipment	3	4.50
2012-02-25	12:30	571 Whitehorse	DJC00074	Foreign Interference	1	2.87
2012-02-28	3:20	577 Destruction Bay	DJC00075	Defective Equipment	150	0.50
2012-02-29	13:00	571 Whitehorse	RSM00173	Foreign Interference	8	1.33
2012-02-29	6:30	577 Destruction Bay	RTW00245	Defective Equipment	2	10.37
2012-03-04	17:10	571 Whitehorse	AMI00133	Unknown/Other	1	0.58
2012-03-09	12:40	578 Beaver Creek	RTW00248	Defective Equipment	2	0.50
2012-03-19	15:00	574 Carcross	SS000359	Unknown/Other	1	22.00
2012-03-19	12:00	571 Whitehorse	RJZ00286	Unknown/Other	1,065	0.64
2012-03-22	13:30	576 Teslin	SMB00042	Foreign Interference	1	2.50
2012-03-23	10:40	590 Lower Post	RGG00033	Unknown/Other	1	0.32
2012-03-25	17:30	574 Carcross	SMB00043	Defective Equipment	1	2.75
2012-03-30	19:39	572 Haines Junction	RTW00249	Loss of Supply - Yukon Energy	524	0.09
2012-03-30	13:50	571 Whitehorse	WAF120330-571	Loss of Supply - Yukon Energy	747	-
2012-03-30	13:50	581 Stewart Crossing	PTM00116	Loss of Supply - Yukon Energy	62	5.36
2012-03-30	13:55	575 Carmacks	WAF120330-575	Loss of Supply - Yukon Energy	289	0.08
2012-03-30	13:50	582 Ross River	WAF120330-582	Loss of Supply - Yukon Energy	218	0.08
2012-03-30	13:50	583 Pelly Crossing	WAF120330-583	Loss of Supply - Yukon Energy	180	0.73
2012-03-30	13:50	594 Deep Creek	WAF120330-594	Loss of Supply - Yukon Energy	45	0.67
2012-04-01	17:00	571 Whitehorse	RSM00175	Foreign Interference	1	1.17
2012-04-03	13:30	574 Carcross	SS0000362	Defective Equipment	1	2.33
2012-04-03	8:00	571 Whitehorse	SMB00044	Foreign Interference	2	7.00
2012-04-04	22:00	576 Teslin	BSP00216	Defective Equipment	1	3.00
2012-04-05	16:00	571 Whitehorse	DSC00076	Foreign Interference	8	1.50

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2012-04-07	13:00	571 Whitehorse	DJC00077	Foreign Interference	2	0.50
2012-04-12	19:48	571 Whitehorse	RJZ00291	Defective Equipment	1	13.57
2012-04-12	12:45	571 Whitehorse	RJZ00290	Foreign Interference	35	0.63
2012-04-13	17:00	571 Whitehorse	SS000363	Foreign Interference	13	-
2012-04-14	11:40	590 Lower Post	RGG00034	Foreign Interference	4	1.08
2012-04-16	13:00	571 Whitehorse	SS000364	Foreign Interference	1	1.50
2012-04-18	8:57	571 Whitehorse	TDR00001A	Unknown/Other	8	0.68
2012-04-20	13:00	571 Whitehorse	SMB00045	Defective Equipment	30	1.30
2012-04-23	9:00	576 Teslin	RJZ00293	Unknown/Other	2	2.58
2012-04-24	9:37	571 Whitehorse	MWG00013	Adverse Weather	3	1.38
2012-04-30	22:26	573 Watson Lake	RGG00035	Trees	270	0.88
2012-05-01	12:00	571 Whitehorse	MWG00014	Defective Equipment	10	5.58
2012-05-02	17:20	571 Whitehorse	AMI00134	Defective Equipment	1	0.17
2012-05-10	10:40	573 Watson Lake	RGG00036	Unknown/Other	1	0.50
2012-05-10	18:09	590 Lower Post	RGG00037	Trees	16	2.00
2012-05-10	10:30	585 Tagish	SS000365	Trees	360	6.50
2012-05-11	12:30	571 Whitehorse	RSM00177	Trees	7	1.58
2012-05-12	10:44	571 Whitehorse	DJC00079	Trees	1	0.93
2012-05-12	11:30	571 Whitehorse	SS000366	Human Element	1	4.00
2012-05-12	12:30	592 Marsh Lake	DJC00080	Trees	1	2.00
2012-05-12	14:18	571 Whitehorse	DJC00081	Trees	200	2.20
2012-05-12	14:18	576 Teslin	DJC00082	Trees	200	4.70
2012-05-13	20:30	573 Watson Lake	RGG00038	Defective Equipment	1	0.47
2012-05-14	17:15	571 Whitehorse	SS000371	Defective Equipment	1	0.50
2012-05-15	13:41	579 Old Crow	PTM00117	Loss of Supply - Yukon Electrical	800	0.02
2012-05-16	5:00	571 Whitehorse	DJC00084	Adverse Weather	6	2.13
2012-05-16	7:00	571 Whitehorse	SS000367	Adverse Weather	2	1.30
2012-05-16	5:30	592 Marsh Lake	DJC00085	Defective Equipment	2	2.83
2012-05-16	5:00	571 Whitehorse	DJC00083	Adverse Weather	20	1.75
2012-05-16	9:00	571 Whitehorse	RJZ00294	Defective Equipment	91	2.28
2012-05-17	13:10	573 Watson Lake	BAC00127	Adverse Weather	1	0.58
2012-05-18	8:10	582 Ross River	SMB00046	Foreign Interference	4	5.08
2012-05-21	12:40	571 Whitehorse	SMB00047	Foreign Interference	2	0.67
2012-05-22	12:00	576 Teslin	SS000370	Foreign Interference	1	121.67
2012-05-23	15:30	571 Whitehorse	SS000372	Defective Equipment	1	1.00
2012-05-24	16:00	572 Haines Junction	BSP00217	Defective Equipment	10	3.50
2012-05-24	18:40	571 Whitehorse	THB00272	Trees	50	1.18
2012-05-25	13:45	571 Whitehorse	SMB00048	Foreign Interference	226	0.98
2012-05-28	9:50	574 Carcross	MPJ00001	Foreign Interference	1	1.50
2012-05-28	6:48	571 Whitehorse	THB00273	Human Element	552	2.28
2012-06-04	8:30	571 Whitehorse	RJZ00296	Foreign Interference	1	0.75
2012-06-04	18:05	579 Old Crow	PTYM00119	Loss of Supply - Yukon Electrical	200	0.02
2012-06-06	10:04	594 Deep Creek	RJZ00300	Trees	14	14.86
2012-06-07	20:46	573 Watson Lake	RGG00039	Trees	290	0.93
2012-06-18	16:55	571 Whitehorse	MPJ00002	Defective Equipment	1	0.33
2012-06-19	12:10	572 Haines Junction	RTW00250	Foreign Interference	1	4.92
2012-06-20	12:41	576 Teslin	RJZ00297	Unknown/Other	351	0.32
2012-06-20	17:30	591 Upper Liard	RGG00044	Defective Equipment	4	1.67
2012-06-20	12:15	576 Teslin	RSM00179	Foreign Interference	3	0.50
2012-06-20	2:50	571 Whitehorse	GLP00015A	Defective Equipment	4	4.22
2012-06-22	22:00	571 Whitehorse	SMB00049	Foreign Interference	5	1.42
2012-06-23	16:00	573 Watson Lake	BAC00128	Unknown/Other	1	0.67
2012-06-24	21:40	585 Tagish	RJZ00298	Trees	59	4.33
2012-06-24	15:00	571 Whitehorse	MWG00016	Trees	5	1.50
2012-06-24	5:55	571 Whitehorse	DRR00276	Foreign Interference	1,995	1.07
2012-06-24	19:30	592 Marsh Lake	MWG00015	Trees	10	3.00
2012-06-24	5:55	583 Pelly Crossing	DRR00277	Foreign Interference	179	3.58
2012-06-25	10:45	573 Watson Lake	RGG00045	Foreign Interference	4	1.08
2012-06-26	13:30	576 Teslin	BAC00129	Unknown/Other	1	2.00
2012-06-27	15:20	573 Watson Lake	RGG00046	Foreign Interference	2	0.93
2012-06-28	11:15	571 Whitehorse	SMB00050	Foreign Interference	15	0.50
2012-06-28	7:40	573 Watson Lake	RGG00047	Unknown/Other	320	0.23
2012-06-28	18:03	579 Old Crow	GDH00009	Scheduled	200	6.95
2012-07-01	10:30	571 Whitehorse	GLP00018	Foreign Interference	1	1.07

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2012-07-04	17:00	578 Beaver Creek	RTW00251	Defective Equipment	2	5.97
2012-07-04	6:30	573 Watson Lake	RGG00048	Foreign Interference	1	0.83
2012-07-07	22:45	571 Whitehorse	RJZ00302	Foreign Interference	1	0.58
2012-07-07	16:00	592 Marsh Lake	RJZ00301	Foreign Interference	1	1.33
2012-07-08	16:40	571 Whitehorse	THB00276	Foreign Interference	1	0.83
2012-07-10	14:30	571 Whitehorse	SMB00051	Trees	14	4.23
2012-07-10	13:45	585 Tagish	ELB00100	Trees	436	11.19
2012-07-10	16:14	573 Watson Lake	RGG00050	Trees	40	1.17
2012-07-10	18:00	592 Marsh Lake	BAC	Trees	1	3.00
2012-07-10	12:15	576 Teslin	BAC00130	Trees	200	5.42
2012-07-10	21:00	592 Marsh Lake	BAC00132	Trees	2	2.00
2012-07-10	7:30	573 Watson Lake	RGG00049	Trees	91	1.27
2012-07-11	11:20	571 Whitehorse	SS000373	Defective Equipment	484	2.42
2012-07-12	9:00	571 Whitehorse	RJZ00305	Foreign Interference	5	0.67
2012-07-12	12:00	585 Tagish	BAC00133	Foreign Interference	1	1.33
2012-07-16	12:00	571 Whitehorse	MWG00017	Trees	1	1.50
2012-07-17	17:03	573 Watson Lake	SMB00053	Trees	1	40.30
2012-07-18	19:00	571 Whitehorse	DRR00273	Defective Equipment	1	3.42
2012-07-18	3:00	573 Watson Lake	SMB00054	Trees	6	4.92
2012-07-19	18:30	571 Whitehorse	MWG00019	Foreign Interference	2	2.75
2012-07-19	10:20	571 Whitehorse	RSM00180	Foreign Interference	8	1.33
2012-07-21	9:50	571 Whitehorse	SS000376	Foreign Interference	4	2.00
2012-07-22	11:30	571 Whitehorse	SS000378	Foreign Interference	1	0.50
2012-07-22	21:15	571 Whitehorse	SS000377	Foreign Interference	9	0.67
2012-07-25	19:25	572 Haines Junction	RTW00252	Scheduled	10	1.42
2012-07-27	17:15	573 Watson Lake	RGG00051	Lightning	240	0.52
2012-07-27	18:15	571 Whitehorse	DJC00086	Defective Equipment	818	1.68
2012-07-27	17:20	573 Watson Lake	RGG00052	Lightning	4	20.42
2012-07-27	17:15	573 Watson Lake	RGG00053	Lightning	1	45.25
2012-07-29	11:00	583 Pelly Crossing	MPJ00004	Defective Equipment	2	15.00
2012-07-29	9:00	571 Whitehorse	MPJ00003	Foreign Interference	2	1.25
2012-07-30	16:30	571 Whitehorse	BAC00134	Foreign Interference	1	19.50
2012-07-30	10:20	571 Whitehorse	SMB00055	Foreign Interference	10	0.50
2012-08-02	14:59	574 Carcross	SMB00056	Human Element	1	5.13
2012-08-03	10:30	571 Whitehorse	MPJ00005	Foreign Interference	1	11.83
2012-08-03	17:45	576 Teslin	SMB00059	Foreign Interference	1	2.77
2012-08-03	19:15	576 Teslin	RGG00054	Trees	328	0.50
2012-08-03	9:00	576 Teslin	SMB00058	Unknown/Other	1	0.13
2012-08-03	6:40	576 Teslin	SMB00057	Foreign Interference	10	2.33
2012-08-04	9:00	571 Whitehorse	RSM00181	Foreign Interference	1	3.00
2012-08-05	21:00	571 Whitehorse	RSM00183	Foreign Interference	126	1.47
2012-08-08	8:05	571 Whitehorse	RJZ00306	Foreign Interference	4	0.92
2012-08-08	8:15	592 Marsh Lake	BAC00135	Foreign Interference	6	1.25
2012-08-10	12:10	571 Whitehorse	RSM00184	Foreign Interference	1,251	0.82
2012-08-11	11:30	571 Whitehorse	DJC00089	Foreign Interference	1	1.42
2012-08-11	9:20	573 Watson Lake	BSP00224	Foreign Interference	1	0.50
2012-08-11	2:30	571 Whitehorse	SJC000088	Foreign Interference	3	6.50
2012-08-12	17:40	571 Whitehorse	AMI00135	Unknown/Other	2	2.08
2012-08-12	7:00	571 Whitehorse	DJC00091	Defective Equipment	1	9.83
2012-08-13	8:30	573 Watson Lake	BSP00225	Foreign Interference	1	0.83
2012-08-13	15:15	592 Marsh Lake	RJZ00307	Foreign Interference	4	1.38
2012-08-13	19:15	571 Whitehorse	AMI00136	Foreign Interference	1	1.25
2012-08-15	15:39	571 Whitehorse	RSM00185	Loss of Supply - Yukon Energy	2,568	0.25
2012-08-16	12:30	571 Whitehorse	MWG00020	Foreign Interference	1	0.83
2012-08-17	22:45	572 Haines Junction	SS000379	Foreign Interference	1	2.75
2012-08-18	20:30	575 Carmacks	SS000380	Unknown/Other	4	3.00
2012-08-19	8:00	571 Whitehorse	BSP00226	Foreign Interference	1	0.83
2012-08-20	17:30	575 Carmacks	TDR00004	Foreign Interference	3	3.00
2012-08-20	7:37	571 Whitehorse	RJZ00308	Foreign Interference	2	2.72
2012-08-21	18:30	594 Deep Creek	SS000381	Foreign Interference	45	1.70
2012-08-23	6:30	585 Tagish	SS000382	Defective Equipment	157	2.70
2012-08-24	14:40	571 Whitehorse	MPJ00006	Foreign Interference	1	-
2012-08-25	10:00	571 Whitehorse	THB00277	Foreign Interference	2	-
2012-08-26	16:00	571 Whitehorse	THB00278	Human Element	2	1.00

Yukon Electrical 2013-2015 GRA
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List of Unplanned Outages from 2008-2012

Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2012-08-26	2:50	573 Watson Lake	GLP00020	Foreign Interference	1	1.67
2012-08-27	13:30	573 Watson Lake	RGG00055	Foreign Interference	14	3.42
2012-08-27	17:30	571 Whitehorse	MWG00024	Trees	2	0.83
2012-08-27	17:30	571 Whitehorse	MWG00022	Foreign Interference	1	1.00
2012-08-27	6:30	573 Watson Lake	GLP00021	Foreign Interference	15	1.50
2012-08-27	22:40	573 Watson Lake	RGG00056	Loss of Supply - Yukon Electrical	1,000	0.45
2012-08-28	12:00	573 Watson Lake	RGG00059	Foreign Interference	4	0.92
2012-08-28	11:30	573 Watson Lake	RGG00060	Unknown/Other	8	2.27
2012-08-28	9:17	573 Watson Lake	RGG00058	Foreign Interference	1	0.27
2012-08-28	7:40	591 Upper Liard	RGG00057	Unknown/Other	13	0.88
2012-08-30	8:00	574 Carcross	SS000383	Unknown/Other	1	4.33
2012-08-31	12:20	571 Whitehorse	RSM00188	Unknown/Other	3	1.33
2012-09-01	17:00	576 Teslin	GLP00022A	Foreign Interference	4	2.50
2012-09-03	18:30	575 Carmacks	GLP00023	Foreign Interference	1	3.17
2012-09-04	5:50	581 Stewart Crossing	RSM00189A	Loss of Supply - Yukon Energy	31	-
2012-09-04	5:50	580 Keno City	RSM00189	Loss of Supply - Yukon Energy	56	1.57
2012-09-04	10:15	573 Watson Lake	RGG00061	Unknown/Other	8	0.55
2012-09-05	14:30	571 Whitehorse	Ss000385	Trees	208	2.17
2012-09-05	18:00	571 Whitehorse	TSM00193	Trees	3	0.50
2012-09-05	18:11	581 Stewart Crossing	RSM00191	Loss of Supply - Yukon Energy	31	0.07
2012-09-05	18:12	582 Ross River	RSM00192	Loss of Supply - Yukon Energy	219	0.05
2012-09-05	18:11	583 Pelly Crossing	RSM00190	Loss of Supply - Yukon Energy	179	0.87
2012-09-07	6:30	581 Stewart Crossing	SMB00062	Defective Equipment	20	9.17
2012-09-07	20:00	571 Whitehorse	SS000384	Trees	1	1.08
2012-09-08	14:50	572 Haines Junction	DRR00280	Loss of Supply - Yukon Energy	525	1.33
2012-09-13	9:34	572 Haines Junction	SMB00061	Foreign Interference	1	2.27
2012-09-13	4:00	571 Whitehorse	MWG00021	Foreign Interference	2	3.75
2012-09-16	14:44	572 Haines Junction	RSM00194	Loss of Supply - Yukon Energy	514	0.08
2012-09-16	21:45	571 Whitehorse	SMB00063	Scheduled	3	0.25
2012-09-24	22:50	573 Watson Lake	RGG00063	Trees	12	1.33
2012-09-24	15:10	571 Whitehorse	AMI00137	Unknown/Other	6	2.83
2012-09-25	17:10	571 Whitehorse	MPJ00007	Foreign Interference	15	1.58
2012-09-26	20:25	571 Whitehorse	AMI00138	Foreign Interference	2	3.08
2012-09-26	13:00	592 Marsh Lake	SS000388	Foreign Interference	2	0.75
2012-09-27	18:00	571 Whitehorse	SMB00064	Trees	2	0.50
2012-09-27	11:45	576 Teslin	MPJ00008	Trees	1	0.23
2012-09-29	17:35	591 Upper Liard	RGG00064	Trees	98	1.32
2012-10-03	11:15	571 Whitehorse	SS000387	Foreign Interference	1	1.08
2012-10-05	10:00	571 Whitehorse	RSM0195	Human Element	10	0.67
2012-10-06	11:00	571 Whitehorse	DJC000092	Foreign Interference	20	2.25
2012-10-07	2:40	572 Haines Junction	WAF121007-572	Loss of Supply - Yukon Energy	495	-
2012-10-07	15:50	571 Whitehorse	DJC00094	Trees	20	2.27
2012-10-07	2:40	571 Whitehorse	WAF121007-571	Unknown/Other	11,584	0.67
2012-10-08	14:15	576 Teslin	THB000280	Trees	217	3.68
2012-10-21	12:00	571 Whitehorse	RSM00196	Adverse Weather	12	1.42
2012-10-26	13:00	571 Whitehorse	MPJ00011	Foreign Interference	3	1.33
2012-10-30	17:30	571 Whitehorse	MPJ00012	Unknown/Other	710	0.42
2012-11-18	10:30	571 Whitehorse	MPJ00013	Unknown/Other	3	1.17
2012-11-18	15:08	571 Whitehorse	SMB00066	Unknown/Other	1	20.62
2012-11-18	21:20	571 Whitehorse	SS000393	Defective Equipment	7	0.33
2012-11-21	23:34	577 Destruction Bay	PTM00120	Loss of Supply - Yukon Electrical	152	0.05
2012-12-01	22:15	571 Whitehorse	RSM00197	Defective Equipment	10	12.83
2012-12-02	19:30	582 Ross River	MPJ00016	Adverse Environment	1	5.83
2012-12-02	16:15	571 Whitehorse	RSM00198	Defective Equipment	1	5.00
2012-12-02	17:28	571 Whitehorse	MPJ00014	Foreign Interference	9	0.53
2012-12-05	13:00	571 Whitehorse	MPJ00017	Adverse Weather	1	25.00
2012-12-09	16:30	571 Whitehorse	AMI00139	Trees	1	0.42
2012-12-11	14:30	582 Ross River	MPJ00018	Defective Equipment	228	0.81
2012-12-14	19:00	590 Lower Post	DJC00095	Defective Equipment	5	3.50
2012-12-15	7:00	573 Watson Lake	DJC00096	Trees	15	2.15
2012-12-16	15:00	571 Whitehorse	MPJ00019	Trees	1	5.00
2012-12-22	16:58	571 Whitehorse	RJZ00311	Defective Equipment	1	1.28
2012-12-23	16:30	571 Whitehorse	SMB00073	Adverse Weather	1	1.08
2012-12-23	21:30	580 Keno City	SS000394	Adverse Weather	56	0.50

Yukon Electrical 2013-2015 GRA
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List of Unplanned Outages from 2008-2012

Date Reported	Time Interrupted	Service Area	Outage Number	CEA Coding	Customers Affected	Customer Average Duration
2012-12-23	15:30	585 Tagish	MWG00026	Adverse Weather	1	1.25
2012-12-23	7:30	571 Whitehorse	SMB00070	Trees	3	1.25
2012-12-23	7:00	571 Whitehorse	MWG00025	Adverse Weather	10	1.00
2012-12-24	16:45	571 Whitehorse	MWG00031	Adverse Weather	6	1.75
2012-12-24	15:45	571 Whitehorse	MWG00030	Adverse Weather	1	1.25
2012-12-24	14:45	571 Whitehorse	MWG00029	Adverse Weather	3	1.25
2012-12-24	7:00	571 Whitehorse	MWG00027	Trees	2	1.50
2012-12-24	1:30	571 Whitehorse	MPJ00026	Adverse Weather	2	9.17
2012-12-24	19:45	572 Haines Junction	SMB00069	Defective Equipment	6	0.58
2012-12-24	12:00	571 Whitehorse	MWG00028	Adverse Weather	1	1.00
2012-12-26	20:30	571 Whitehorse	RJZ00313	Adverse Environment	1	2.17
2012-12-30	11:30	571 Whitehorse	SMB00071	Adverse Weather	4	0.83

Yukon Electrical 2013-2015 GRA
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Performance Criteria from 2008-2012 for Unplanned Outages

Year	CEA Coding	SAIFI	SAIDI	CAIDI	Index of Reliability
2008	Adverse Environment	0.00	0.00	2.54	100.000%
	Adverse Weather	0.17	0.09	0.52	99.999%
	Defective Equipment	0.44	0.26	0.60	99.997%
	Foreign Interference	0.39	0.54	1.40	99.994%
	Human Element	0.01	0.01	1.08	100.000%
	Lightning	0.00	0.00	0.89	100.000%
	Loss of Supply - Yukon Electrical	0.38	0.13	0.34	99.999%
	Loss of Supply - Yukon Energy	5.86	6.41	1.09	99.927%
	Trees	0.68	1.38	2.02	99.984%
	Unknown/Other	0.17	0.11	0.66	99.999%
2008	**TOTAL COMPANY**	**8.10**	**8.94**	**1.10**	**99.898%**
2009	Adverse Environment	0.00	0.01	2.03	100.000%
	Adverse Weather	0.13	0.20	1.60	99.998%
	Defective Equipment	0.68	0.61	0.89	99.993%
	Foreign Interference	0.38	0.33	0.87	99.996%
	Human Element	0.03	0.02	0.70	100.000%
	Lightning	0.01	0.01	0.99	100.000%
	Loss of Supply - Yukon Electrical	0.22	0.05	0.24	99.999%
	Loss of Supply - Yukon Energy	5.68	3.09	0.54	99.965%
	Scheduled	0.01	0.01	1.75	100.000%
	Trees	0.17	0.27	1.60	99.997%
	Unknown/Other	0.38	0.27	0.71	99.997%
2009	**TOTAL COMPANY**	**7.68**	**4.87**	**0.63**	**99.944%**
2010	Adverse Environment	0.00	0.00	6.96	100.000%
	Adverse Weather	0.18	0.10	0.57	99.999%
	Defective Equipment	0.07	0.07	0.91	99.999%
	Foreign Interference	0.07	0.22	3.19	99.998%
	Human Element	0.04	0.02	0.54	100.000%
	Lightning	0.01	0.02	2.58	100.000%
	Loss of Supply - Yukon Electrical	0.21	0.03	0.13	100.000%
	Loss of Supply - Yukon Energy	2.40	1.36	0.57	99.984%
	Scheduled	0.02	0.00	0.07	100.000%
	Trees	0.17	0.41	2.41	99.995%
	Unknown/Other	0.19	0.07	0.36	99.999%
2010	**TOTAL COMPANY**	**3.35**	**2.30**	**0.69**	**99.974%**
2011	Adverse Environment	0.01	0.00	0.38	100.000%
	Adverse Weather	0.04	0.03	0.62	100.000%
	Defective Equipment	0.18	0.38	2.10	99.996%
	Foreign Interference	0.52	0.46	0.89	99.995%
	Human Element	0.04	0.04	1.03	100.000%
	Lightning	0.10	0.02	0.21	100.000%
	Loss of Supply - Yukon Electrical	0.18	0.06	0.33	99.999%
	Loss of Supply - Yukon Energy	3.94	4.37	1.11	99.950%
	Trees	0.38	0.57	1.52	99.993%
	Unknown/Other	0.22	0.16	0.73	99.998%
2011	**TOTAL COMPANY**	**5.61**	**6.09**	**1.08**	**99.930%**
2012	Adverse Environment	0.00	0.00	4.00	100.000%
	Adverse Weather	0.10	0.04	0.42	100.000%
	Defective Equipment	0.47	0.95	2.00	99.989%
	Foreign Interference	0.25	0.29	1.18	99.997%
	Human Element	0.03	0.08	2.26	99.999%
	Lightning	0.01	0.02	1.03	100.000%
	Loss of Supply - Yukon Electrical	0.15	0.03	0.19	100.000%
	Loss of Supply - Yukon Energy	0.42	0.17	0.41	99.998%
	Scheduled	0.01	0.08	6.60	99.999%
	Trees	0.21	0.81	3.86	99.991%
	Unknown/Other	0.85	0.54	0.64	99.994%
2012	**TOTAL COMPANY**	**2.51**	**3.02**	**1.20**	**99.966%**

The Yukon Electrical Company Limited
Actual 2008/2009 Capital Additions vs. 2008/2009 GRA Capital Forecast

Project Name	2008 GRA	2008 Actual	Variance	%	2009 GRA	2009 Actual	Variance	%	Variance Explanations (>10% Variance)
Haines Junction Plant Upgrades	91,500	100,000	(8,500)	-9.29%			-		
Pelly Crossing Tie into Transmission Grid	120,000	92,500	27,500	22.92%			-		Scope was adjusted after filing GRA.
Fish Lake Unit #1 Generator Rebuild	125,000	463,000	(338,000)	-270.40%			-		Original estimate was created from 3rd party shutdown and inspection of generator that recommended the generator needed to be cleaned and stator core work. When unit was removed from service and sent to generator shop, an indepth inspection found generator at end of life which required a complete rebuild of the unit.
Other 2008	677,500	56,000	621,500	91.73%			-		Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Destruction Bay Compton Protection Relay Replacement and Battery Charg		65,000	(65,000)	-100.00%			-		This project was done in preparation for plc upgrade.
Watson Lake Generator Upgrades and Fresh Air Intakes		76,500	(76,500)	-100.00%			-		This project was completed to counter the new low sulphur diesel fuel which burned hotter and drier on the intake valves.
Destruction Bay Programmable Logic Controller Upgrade			-		77,000		77,000	100.00%	Project was deferred due to the delay in the first step of upgrading Compton protection relays.
Fish Lake Control Room Monitor Upgrade			-			52,000	(52,000)	-100.00%	These are monitors for the water levels at various location on the system. These monitors were required by YESAB in preparation of our long term licence application.
Fish Lake Incremental Purchase Power	69,000	-	-		69,000	69,000	(69,000)	-100.00%	Purchase power as directed by YUB
Fish Lake Unit # 1 Replacement Wheel			-			80,000	(80,000)	-100.00%	This is a partial payment for the replacement wheel for unit #1. This was not in previous budgets due to previously good reports on the wheel condition. When generator was rebuilt the wheel was inspected and it needed replacing.
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal			-		130,000	153,000	(23,000)	-17.69%	The cost of the new wheel and shaft were higher than budgeted.
Haines Junction Plant Controls Upgrade			-			324,000	(324,000)	-100.00%	Project was not budgeted as a part of the 2008/2009 GRA. During upgrade work in 2008, the plant foundation was sinking. A new concrete foundation was put in place. This required significant civil works, electrical and fuel system adjustments.
Old Crow Plant Expansion			-		100,000		100,000	100.00%	The project was deferred as scope changed as a result of inability to expand current facility.
Other 2009			-		590,000	69,000	521,000	88.31%	Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Swift River Unit # 1 Replacement			-			32,000	(32,000)	-100.00%	Purchase of unit for 2010 installation. Purchased unit ahead of install for a contingency during winter months.
Fish Lake Weir in Ditch # 3 or Gate			-		150,000		150,000	100.00%	This project was deferred based on Dam Safety Report
Old Crow Design PLC Replacement			-		77,000		77,000	100.00%	The project was deferred as it was tied to expansion project.
	1,083,000	**853,000**	**161,000**	**14.87%**	**1,193,000**	**779,000**	**345,000**	**28.92%**	
CIS Billing System Conversion	1,008,000	1,035,000	(27,000)	-2.68%			-		
	1,008,000	**1,035,000**	**(27,000)**	**-2.68%**	**-**	**-**	**-**		
Land Rights	90,000	100,000	(10,000)	-11.11%	90,000	56,000	34,000	37.78%	Land rights are licences to secure right of way for power line and the small variance is due to additional licences required based on customer demand for power lines.
4th Ave and Strickland Condominiums	98,850	92,000	6,850	6.93%			-		
Little Atlin Feeder Tap	150,000	178,000	(28,000)	-18.67%			-		Customer driven project where the final construction costs came in higher than forecast due to difficulty in digging in the ground.
Miscellaneous New U/G Services	165,000	95,000	70,000	42.42%	219,615	36,000	183,615	83.61%	The forecast is based on historical actuals and known customer demand. The variance is due to changes in customer demand in the year.
Ta'an Kwach'an Council Subdivision - Klondike Highway N	168,590		168,590	100.00%		60,000	(60,000)		This project was deferred at customer's request from 2008 to 2009 and completed in 2010.
Stan McCowan Subdivision	214,925	126,000	88,925	41.37%			-		This project was customer driven and the actual scope of the subdivision was less than estimated when created GRA budget.
Yukon Government Whitehorse Copper Phase II	225,000	262,000	(37,000)	-16.44%			-		This project was customer driven and the actual scope of the subdivision was more than we estimated when created GRA budget.
Hamilton Boulevard Main Infrastructure Extension	300,000	266,000	34,000	11.33%		100,000	(100,000)	-100.00%	This project was customer driven and the actual scope of the subdivision was less than we estimated when created GRA budget.
New Customer Connection at Minto Crossing	350,000	40,000	310,000	88.57%			-		This project was customer driven and when we started this project in 2008 and did not complete the work until 2012 due to customer funding amd land issues.
Mountain Air Subdivision	382,160	317,000	65,160	17.05%			-		This project was customer driven and the actual scope of the subdivision was less than we estimated when created GRA budget.
Other 2008	996,475	79,000	917,475	92.07%			-		Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Lot 10 Centennial Street		28,000	(28,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
Carcross Tagish First Nation Carcross Line Rerouting		32,000	(32,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
Whitehorse Cadet Camp Three Phase Service		40,000	(40,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
General Drafting and Mapping		46,000	(46,000)	-100.00%		75,000	(75,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Connection of Minto Landing into Yukon Interconnected System		47,000	(47,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
Lot 16 Marwell Subdivision		53,000	(53,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
Skookum Asphalt Plant		61,000	(61,000)	-100.00%			-		This project was customer driven and not known until after the 2008/2009 GRA was filed
Arkell Subdivision Infill		78,000	(78,000)	-100.00%	650,000	717,000	(67,000)	-10.31%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Miscellaneous O/H Services - Various Subdivisions		1,304,000	(1,304,000)	-100.00%	95,167	969,000	(873,833)	-918.21%	Miscellaneous other overhead extensions is made up of all the small new extensions that are majorily customer contributed. This was budgeted in Other Projects, but shown separately in the 2013-2015 GRA.
35 Unit Condominium Wann Road			-			53,000	(53,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Burns Road Lot Development			-			86,000	(86,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Champagne Aishihik First Nation Subdivision			-			36,000	(36,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
City of Whitehorse Public Safety Building			-			61,000	(61,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Lot 1095 Gentain Lane			-			41,000	(41,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
New Whitehorse Correctional Centre			-			90,000	(90,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Northwestel Communication Tower Hotsprings Road			-			27,000	(27,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed

The Yukon Electrical Company Limited
Actual 2008/2009 Capital Additions vs. 2008/2009 GRA Capital Forecast

Project Name	2008 GRA	2008 Actual	Variance	%	2009 GRA	2009 Actual	Variance	%	Variance Explanations (>10% Variance)
Other 2009			-		1,717,218	100,000	1,617,218	94.18%	Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Selkirk First Nation Child Care Center			-			36,000	(36,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Takhini Lot 1371			-			33,000	(33,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Takhini North Infill			-			341,000	(341,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Teslin Seniors 8-Plex			-			40,000	(40,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Two City Water Wells in Riverdale			-			107,000	(107,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Watson Lake Line Move			-			35,000	(35,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Whistle Bend Subdivision Stage 1 & 2			-		190,000		190,000	100.00%	This project was deferred until the 2011 year due to developer demands
Whitehorse General Hospital Staff Residence			-			32,000	(32,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Whitehorse Lot 1097			-			46,000	(46,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Yukon Government Army Beach Sweage Lagoon			-			47,000	(47,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Yukon Government Carcross Water Front Place			-			35,000	(35,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Yukon Government Carmacks Sewer Treatment Plant			-			32,000	(32,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Yukon Government New Airport Parking Area			-			58,000	(58,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
Yukon Housing 8-Plex			-			88,000	(88,000)	-100.00%	This project was customer driven and not known until after the 2008/2009 GRA was filed
	3,141,000	**3,244,000**	**(103,000)**	**-3.28%**	**2,962,000**	**3,437,000**	**(475,000)**	**-16.04%**	
Cadet Camp Three Phase Service System Improvement	85,000	83,000	2,000	2.35%			-		
Right of Way Widening	110,000	268,000	(158,000)	-143.64%		240,000	(240,000)	-100.00%	In 2008, the scope increased on the basis of line patrols as Yukon Electrical focused on completing brushing of our mountain top distribution lines in Whitehorse and Stewart Crossing. In 2009, the right of way brushing program continued.
5L628 Squanga Road Rebuild	140,000	290,000	(150,000)	-107.14%			-		The original scope and estimate of the project was to rebuild the powerline in an overhead configuration. Due to location of existing water lines being different than original plan a new route was needed. Due to conficts with property lines, existing vegetation, water lines and the existing power line the new power line was built with underground infrastructure.
Connect Pelly Crossing into Yukon Interconnected Systen	140,000	435,000	(295,000)	-210.71%			-		The original scope and budget was to build infrastructur to connect to YEC substation. YEC did not build the substation as planned and temporarily energized the new 138kv line at 25 kv from Minto substation to supply Pelly Crossing from the YIS. Yukon Electrical built a mini substation that required site preperation including a ground grid, a regulator bank, metering equipment and temporary underground line to connect to YEC supply on the 138kV pole.
Miscellaneous Pole Replacements	146,500	92,000	54,500	37.20%	160,500	22,000	138,500	86.29%	Miscellaneous pole change outs depend upon the need to replace the poles in the system. Each year we budget certain amount and the need to change is driven by the test results that come from test & treat program and line patrols.
9L - Km 129 to Km 132 South Klondike Highway - Distribu	150,000	189,000	(39,000)	-26.00%			-		Project increase was due to terrain and access difficulties for this section of line.
Ketza Court Live Front Transformers Replacement	175,000	346,000	(171,000)	-97.71%			-		Original scope and estimate was for 2 transformers and underground cable. Increased scope to complete all 5 transformers in the complex and associated underground infrastructure.
9L Reliability Upgrade Squanga Lake Area	180,000	77,000	103,000	57.22%	180,000	51,000	129,000	71.67%	The project scope was significantly reduced as structure upgrades were possible in multiple locations without having to change pole. The existing pole and wire were able to be re used. This significantly cut the costs and time to complete work while successfully increasing reliability.
Tagish 5L600 Rebuild	180,000		180,000	100.00%			-		This project was deferred due to higher priority projects and adequate performance of feeder.
Pelly Crescent to Grey Mountain H Frames	200,000		200,000	100.00%			-		This project was deferred due to higher priority projects and adequate performance of feeder.
4L311 Upgrade Distribution Lines Between 1st and 6th Av	400,000	439,000	(39,000)	-9.75%			-		
Other 2008	1,060,500	291,000	769,500	72.56%			-		Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Arkell Substation Upgrade		21,000	(21,000)	-100.00%		197,000	(197,000)	-100.00%	Distribution load growth was exceeding the existing 5MVA transformer. The transformer was replaced with a 10MVA and small upgrades were needed in the substation also.
Marwell Subdivision Improvements		21,000	(21,000)	-100.00%			-		Fixed clearance issues and leaning pole on quartz road crossing.
Convert Spirit Lake to 14.4kV		22,000	(22,000)	-100.00%			-		Design completed.
McDonald Road to Centennial Road Upgrade		23,000	(23,000)	-100.00%		24,000	(24,000)	-100.00%	This project addressed clearance concerns identified by system inspections.
McIntyre Creek Pumphouse Upgrade		23,000	(23,000)	-100.00%			-		Upgrade due to load and new requirements.
North Star Clearance Upgrade		24,000	(24,000)	-100.00%			-		Fixed clearance issue
Beaver Creek Planned Pole Replacements		25,000	(25,000)	-100.00%			-		This project was identified by system inspections.
Porter Creek Regulator Upgrade		26,000	(26,000)	-100.00%			-		Replaced a regulator
Carmacks Planned Pole Replacements		28,000	(28,000)	-100.00%			-		This project was identified by system inspections.
Paddlewheel Line Relocation		30,000	(30,000)	-100.00%			-		Forced project due to customer project in the area.
Carmacks Upper Bench Rerouting		31,000	(31,000)	-100.00%			-		This project was identified by system inspections.
Campbell Highway Relocation		43,000	(43,000)	-100.00%			-		Yukon Government highway widening required pole relocations.
Birch Alley Upgrade		45,000	(45,000)	-100.00%		32,000	(32,000)	-100.00%	This project was identified by system inspections.
Morley Bay Line Upgrade		46,000	(46,000)	-100.00%			-		Project upgraded a 1970 line for improved reliability and performance.
McIntyre Subdivision 34.5kV Upgrade		47,000	(47,000)	-100.00%			-		Project built new overhead powerline to bypass and remove failing underground system
Echo Lake Road Upgrade		52,000	(52,000)	-100.00%		75,000	(75,000)	-100.00%	This project was identified by system inspections.
Little Atlin Lake Area 3 Phase Pole Upgrades		60,000	(60,000)	-100.00%			-		This project was done at the same time as a new customer extension. YECL's upgrade was for reinforced infrastructure in preparation for future upgrade of line.
Tagish Bridge Conduit Replacement		60,000	(60,000)	-100.00%			-		This project was identified by system inspections. Old conduit system had separated exposing cable. New system is designed to flex not separate.
Test and Treat Pole Program		72,000	(72,000)	-100.00%			-		Originally included in the Other Projects budget.
Hillcrest Subdivision Conversion		93,000	(93,000)	-100.00%	250,000	152,000	98,000	39.20%	Project was designed and started to convert from 12kV to 25kV to off load the mountainview sub.
System Upgrades Lot 1378/79 Range Road		93,000	(93,000)	-100.00%	184,000		184,000	100.00%	Forced project due to customer project in the area.
Liard River Crossing			-			29,000	(29,000)	-100.00%	This project was identified by system inspections. The project is designed.
Other 2009			-		832,500	168,000	664,500	79.82%	Other projects were forecasted based on historical capital costs and does not relate to one specific project.

The Yukon Electrical Company Limited
Actual 2008/2009 Capital Additions vs. 2008/2009 GRA Capital Forecast

Project Name	2008 GRA	2008 Actual	Variance	%	2009 GRA	2009 Actual	Variance	%	Variance Explanations (>10% Variance)
Robinson Substation Upgrade			-			39,000	(39,000)	-100.00%	This project was identified by system inspections.
System Upgrade on Hotsprings River Road			-			22,000	(22,000)	-100.00%	Pole Relocation due to Yukon Government building sewer lift station in the area.
Teslin and Klondike Road Upgrade			-		200,000	20,000	180,000	90.00%	Project was started in 2009 and not completed until 2010.
Watson Lake Hotel Upgrade			-			20,000	(20,000)	-100.00%	Forced project due to customer project in the area.
Whitehorse Airport Conversion			-			29,000	(29,000)	-100.00%	Forced project due to customer project in the area.
Wickstrom Road Line Relocation for Whitehorse General Hospital Residence and Medical B			-			83,000	(83,000)	-100.00%	Forced project due to customer project in the area.
Carcross Relocate 34 kV Stage 2			-		150,000		150,000	100.00%	This project was deferred due to higher priority projects and adequate performance of feeder. Brushing was also completed in the area.
Carmacks One Phase Line by Heli Pad on Highway			-		75,000		75,000	100.00%	This project was deferred due to higher priority projects and adequate performance of feeder.
Tagish Section to Taku 2.5 km			-		200,000		200,000	100.00%	This project was deferred due to higher priority projects and adequate performance of feeder.
Lambert Street - DQ Alley			-		300,000		300,000	100.00%	This project was deferred due to higher priority projects and adequate performance of feeder.
	2,967,000	**3,395,000**	**(428,000)**	**-14.43%**	**2,532,000**	**1,203,000**	**1,329,000**	**52.49%**	
4th Ave and Strickland Condominiums	100,000	84,000	16,000	16.00%			-		This project was part of a customer driven distribution project. We upgraded the street lights when the trench was open. Cost savings due to co-ordination with the distribution project.
ALSEK/Highland Area	100,000		100,000	100.00%			-		This project was deferred due to higher priority jobs at the time.
Pine Street Light Replacement	106,000	25,000	81,000	76.42%			-		Design work and part of civil work were done in 2008. Due to the priority of other projects at the time, Yukon Electrical could not complete this project in 2008. Project was deferred.
Hamilton Boulevard Extension	200,000	435,000	(235,000)	-117.50%		41,000	(41,000)	-100.00%	A Yukon Government contributed project, scope was increased at customers request.
Carmacks High Pressure Sodium Light Upgrade		20,000	(20,000)	-100.00%			-		Project was completed as existing lights had failed.
Quartz Road Street Lights Relocation		21,000	(21,000)	-100.00%			-		Customer contributed and forced project for a sidewalk installation.
4th Ave & Strickland Light Upgrade		41,000	(41,000)	-100.00%			-		This was a customer driven project due to work in the area.
Foxhaven Street Lights Relocation		82,000	(82,000)	-100.00%			-		A customer driven light change that was fully contributed.
Whitehorse Copper Light Additions		131,000	(131,000)	-100.00%			-		A customer driven light change that was fully contributed.
Miscellaneous Street Light Replacements			-		230,000		230,000	100.00%	This was a budget based on small project historical actuals. The actual costs for this project are represented by the unbudgeted projects performed in 2009.
Other 2009			-		15,000	60,000	(45,000)	-300.00%	Other projects were forecasted based on historical capital costs and does not relate to one specific project.
Ta'an Kwach'an Council Subdivision			-			54,000	(54,000)	-100.00%	Customer driven fully contributed project that was part of the new Ta'an Kwachin subdivision on Mayo Road.
Takhini North Subdivision			-			86,000	(86,000)	-100.00%	Customer driven fully contributed project that was part of the new Takhini subdivision.
Yukon Government Ingram Subdivision Street Lights			-			113,000	(113,000)	-100.00%	Customer driven fully contributed project that was part of the new Ingram subdivision.
Mountainview/Other			-		250,000		250,000	100.00%	This project was deferred in part due to discussions with CoW of possible other improvements in area.
	506,000	**839,000**	**(333,000)**	**-65.81%**	**495,000**	**354,000**	**141,000**	**28.48%**	
Meters General		31,000	(31,000)	-100.00%			-		
	-	**31,000**	**(31,000)**		**-**	**-**	**-**		
Transformers & Regulators			-			80,000	(80,000)	-100.00%	Unplanned transformer purchase to replenish out-dated equipment.
	-	**-**	**-**		**-**	**80,000**	**(80,000)**		
Computers	6,000		6,000	100.00%	5,000		5,000	100.00%	No new computers for dispatch were purchased in 2008 or 2009.
Office Furniture	13,000		13,000	100.00%	10,000		10,000	100.00%	No new desks were purchased in 2008 or 2009.
Miscellaneous Tools and Instruments	50,000	45,000	5,000	10.00%	57,000	37,000	20,000	35.09%	2009 - Equipotental bonding requirements were not completed per AE as forecasted.
Communication Equipment	102,000	57,000	45,000	44.12%	54,000	47,000	7,000	12.96%	Phone isolation costs in substations were carried over to future years,
Transportation Equipment	205,000	139,000	66,000	32.20%	230,000	100,000	130,000	56.52%	2008 - New fork lift purchase was deferred to future years and 2009 - unit 956 deferred to 2010 due to GVWR considerations.
Miscellaneous Land and Buildings	218,000		219,000	100.46%			-		Forecast based on historical actuals. Budget was used on various projects.
Whitehorse Service Complex Pole Shed for storage		51,000	(51,000)	-100.00%			-		Material storage outstripped our existing warehouse space.
Other 2008		79,000	(79,000)	-100.00%			-		Part of the misc land and buildings.
Oracle Hrxcellence HR Management		138,000	(138,000)	-100.00%		117,000	(117,000)	-100.00%	Unplanned change to company HR management system
Old Crow Staff Accomodations			-		180,000		181,000	100.56%	This project was deferred due to cancellation of building the winter road.
Other 2009			-			99,000	(99,000)	-100.00%	Other projects were forecasted based on historical capital costs and does not relate to one specific project.
	594,000	**509,000**	**86,000**	**14.48%**	**536,000**	**400,000**	**137,000**	**25.56%**	
	9,299,000	**9,906,000**	**(675,000)**		**7,718,000**	**6,253,000**	**1,397,000**		

YCS-YECL-1-1

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain whether LED street lights were used for the completed new lighting installations. Why or why not?

Response:

LED street lights were not used for any street light installations for the years 2009 - 2012. Yukon Electrical has partnered with YEC in a joint pilot project study to determine the LED technology best suited for the Yukon. This pilot project is currently testing four different LED lights including a stock ATCO Electric 43W LED light. The pilot project study will be completed by the end of 2013. Yukon Electrical will fully consider the results of the LED light study for future installations of street lights.

Yukon Electrical believes that it is prudent to have thorough testing completed prior to installing LED lights in order to ensure that the LED lights perform to the standard for light intensity and lighting patterns for the Yukon.

YCS-YECL-1-2

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain whether LED street lights will be used for the upcoming lighting installations. Why or why not?

Response:

The forecast included in Yukon Electrical's Application does not incorporate the installation of LED street lights in the test period. However, Yukon Electrical has partnered with YEC in a joint pilot project study to determine the LED technology best suited for the Yukon. This pilot project is currently testing four different LED lights, including the 43W LED light which is the standard LED light kept in stock by ATCO Electric. The pilot project study will be completed by the end of 2013.

Yukon Electrical believes that it is prudent to have thorough testing completed prior to installing LED lights in order to ensure that the LED lights perform to the standard for light intensity and lighting patterns for the Yukon.

YCS-YECL-1-3

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain why there are no predicted reductions in energy use for street lighting when technology exists to significantly reduce electricity consumption in street lighting.

Response:

Yukon Electrical has partnered with Yukon Energy in a joint pilot project study to determine the best suited LED streetlight technology for the Yukon. This pilot project is currently testing four different LED lights including the selected brand and model of 43W LED light that ATCO Electric uses. The pilot project study is expected to be completed by the end of 2013.

To date Yukon Electrical has not installed any LED streetlights other than a select few for testing purposes. Yukon Electrical has determined that it is prudent to have thorough testing completed to ensure the LED lights perform to standard light intensities and lighting patterns for the Yukon. Therefore, Yukon Electrical has not incorporated any LED streetlight conversions in the sales forecast. As a result, the wattage and average use per light is constant. Therefore, there are no predicted reductions in energy use for street lighting.

YCS-YECL-1-4

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please provide any reporting or results from any LED streetlight pilot programs undertaken by the utility (as in, results showing the cost difference in LED street lights versus HPS lights, how much electricity is saved, what is the payback time, what is the lighting effectiveness, what are potential issues, do LEDs meet highway lighting standards, etc).

Response:

Although ATCO Electric has a stock item 43W LED light to replace 100W street lights, Yukon Electrical has partnered with YEC in a joint pilot project study to determine the LED street light technology best suited for the Yukon. This pilot project is currently testing four different LED lights, including the selected ATCO Electric 43W LED light. The pilot project study will be completed by the end of 2013.

In addition to the pilot project study, Yukon Electrical has discussed with ATCO Electric the benefits and performance of this light in ATCO Electric's northern Alberta communities. To date, Yukon Electrical has not installed LED streetlights other than a select few for testing purposes. Yukon Electrical believes that it is prudent to have thorough testing completed prior to installing LED lights in order to ensure that the LED lights perform to the standard for light intensity and lighting patterns for the Yukon.

YCS-YECL-1-5

Reference: Street Lighting

Table 1 (Yukon Electrical Sales by Customer Class) on page 2-2 of the GRA document shows MWh for streetlights increasing from 3,598 in 2011 (actual) to 3,854 (predicted) in 2015. On GRA page 2-6, it explains that: "the energy forecast for street and private lighting is based on wattage and customer additions."

A total of $4,519,000 has been and will be spent on streetlights from 2009 to 2015 (2009: $354,000; 2010: $486,000; 2011: $1,045,000; 2012: $456,000; 2013: $420,000; 2014: $945,000; 2015: $813,000).

Request:

Please explain how street lighting fits or doesn't fit into the DSM Plan and its overall goal for reducing energy consumption and increasing efficiency for lighting.

Response:

A joint study by Yukon Electrical and Yukon Energy is underway to determine the technology that will be best suited for the Yukon, with a report of the results expected to be delivered by the end of 2013. The results of this technology evaluation work will be utilized separately from the DSM plan to outline a proposed approach for rate design approval by the YUB that addresses the higher capital cost of LED streetlights and the reduced electricity consumption cost.

YCS-YECL-2-1

Reference: Watson Lake Bi-Fuel Project

"Phase 1 of the project (2013) involves the modification of Watson Lake power plant generation unit #5 to a bi-fuel system, which allows the unit to run on a combination of diesel and natural gas. The purpose of this phase is to verify that NG injection into the engine provides reliable electricity generation for a utility power system along with the environmental benefit to reduce emissions."

Request:

Please provide peer-reviewed reference documentation and describe the basis of YECL's assumption and claims that burning LNG with diesel rather NG injection into the engine will result in an environmental benefit.

Response:

By chemical composition, natural gas is known to result in fewer environmental emissions than diesel.

For the purposes of clarification, liquefied natural gas (LNG) is non-combustible until it is vaporized back to natural gas.

The primary driver for the Watson Lake Bi-Fuel project is to provide local emissions reductions. It is predicted that there will be a reduction in CO_2, particulate matter (PM) emissions, important to people with compromised lung function, and NOx and SOx, contributing to smog and acid rain.

A bi-fuel system can have different characteristics than a unit which uses 100% natural gas or 100% diesel. In December 2012, SENES (please refer to YCS-YECL-2-1 Attachment 1 for *Literature Review: Air Contaminant Emissions from Dual-Fuelled and Conventional Diesel Generator Operations*) completed a literature study to summarize existing information on air contaminant emissions for bi-fuel systems and used this information to predict how previously modeled air emissions are affected by the proposed bi-fuel modification of one engine in the power plant. SENES concluded that emission levels for nitrogen oxide (NO_x), particulate matter (PM) or soot, and sulphur dioxides (SO_2) are expected to decrease, while emissions of unburned hydrocarbons (HC) and carbon monoxide (CO) are expected to increase. The increase

in CO, however, is expected to remain well below Yukon air quality standards. There are no Yukon standards that apply to the HC that are expected to be emitted; however, the actual quantities are expected to be low.

As emissions of CO_2, CO, NO_x and unburned HCs in the combustion products are engine specific, the details on emissions will not be fully understood until the project is in operation and emissions sampling is complete.

For additional information, please refer to YCS-YECL-2-7 and YUB-YECL-42(f).

Literature Review:
Air Contaminant Emissions from Dual-Fuelled and Conventional Diesel Generator Operations

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28 November 2012

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1.0 INTRODUCTION

The Yukon Electrical Company Limited (YECL) is proposing to conduct a pilot-scale dual-fuelled power generation testing program at its current power generating station in Watson Lake, YK. The pilot-scale testing program will determine the feasibility of operating one of the diesel generators on a combination of diesel and natural gas. If the pilot scale program is successful, YECL will consider converting the remaining five units at the station to dual-fuelled operation.

YECL is proposing to use a ComAp Bi-Fuel™ system on a Cat 3508 700kW engine at the Watson Lake generating station. It should be noted that the term *Bi-Fuel* can be defined as the simultaneous combustion of two fuels. In the case of the Bi-Fuel System, natural gas is utilized in conjunction with diesel fuel to operate the engine. After conversion, the engine is able to operate on either 100% diesel fuel, or alternately, on a mixture of diesel fuel and natural gas (or other methane-based fuels). At no time would the engine be able to operate on natural gas exclusively. In practice, the terms *Bi-Fuel* and *Dual Fuel* are often used interchangeably, and this is the way that the terms are used in this report and in the literature cited in this report.

As part of the assessment of the dual-fuelled testing program, YECL retained SENES to provide assistance on air quality-related issues for the proposed testing program. SENES completed a dispersion modelling analysis of emissions from the existing diesel-fuelled generators at the Watson Lake station in 2009 in support of the station's permit renewal application. Since emissions for the dual-fuelled generators will differ from pure diesel-fuelled operation, a literature search was conducted to assess the potential effect that converting from diesel to dual-fuel operation might have on anticipated air contaminant emissions and subsequent air concentrations for common air contaminants.

Only a limited number of published papers were identified in the literature search which were considered to be directly applicable to the YECL pilot-scale testing program. However, the information gathered from these published studies is sufficient to provide an estimate of the likely changes in emissions that could result from the switch from diesel to dual-fuelled operation, and the potential effect these emission changes would have on predicted ambient concentrations based on the previous air dispersion modelling analysis.

2.0 CHANGES IN EMISSIONS

The following provides a summary of information about the types of changes in emissions of nitric oxide (NO), carbon monoxide (CO), unburned hydrocarbons (HC), sulphur dioxide (SO_2) and soot or particulate matter (PM) that have been reported in published literature on the differences between operating power generators on diesel only and on a combination of diesel and natural gas.

2.1 NO EMISSIONS

The overall conclusion of all published sources reviewed for this report is that dual-fuel operation results in lower nitrogen oxide (NOx) emissions. A study was performed by R.G. Papagiannakis and D.T. Hountalas (2003) observing emissions of contaminants during dual-fuel operation of a diesel engine using natural gas as the secondary fuel. The study showed that NO emissions are lower during dual-fuel operation when natural gas is used as the secondary fuel. According to the study,

> *"..a possible explanation…is the less intense premixed combustion, the reduction of gas temperature due to increase of the specific heat capacity, the slower combustion and finally the reduction of oxygen concentration due to presence of the natural gas mass ration, which replaces an equal amount of air in the cylinder charge."*

Abdelghaffar (2011), citing previous work by Papagiannakis and Hountalas, also stated that NOx concentrations in exhaust are lower for dual-fuelled operation compared to normal diesel operation. This was also confirmed by R.G. Papagiannakis et al. (2010) who showed in a controlled study that:

> *"...for the same combination of engine operating conditions (i.e., engine speed and load), the increase of the liquid fuel supplementary ratio (x>0%)* [the higher the percentage of natural gas] *leads to lower NO concentrations compared to the ones observed under normal diesel operation (x=0%)".*

The study also noted that at high loads and engine speeds, NO emissions start to increase beyond a certain natural gas percentage. R.G. Papagiannakis et al. (2010) speculate that this is caused by warmer engine temperatures and an increase in turbulence within the combustion chamber.

Figure 2.1 shows the changes in NO emissions reported by Papagiannakis et al. (2010) for various engine loads, engine speeds and the relative proportion of natural gas substitution for diesel in the fuel. The authors reported that:

- at low and intermediate load conditions and for all engine speeds
    - Increased gaseous fuel substitution results in a decrease in NO emissions, with reductions of up to 60% at low load operation
- at high load and low engine speeds, NO emissions may be reduced by up to 47%
- at high load and high engine speeds, specific NO emission rates start to decrease with the increase in diesel fuel substitution rates, but still remain lower than when the engine is run on diesel alone.

At 80% load and high engine speed, Papagiannakis et al. (2010b) estimated that NO emission concentrations could, theoretically, approach or slightly exceed emissions under normal diesel fuel operations at high inlet air temperatures (90˚C), but would remain lower than for diesel only operations at lower inlet air temperatures.

Similar results are shown in Sahoo et al. (2009), who reported that:

> *"…at low loads the NOx concentration under dual fuel operation is slightly lower compared to the one under normal diesel operating conditions…At higher load, the NOx concentration under dual fuel operation is considerably lower compared to the one under normal diesel operation."*

As indicated in Figure 2.2, Sahoo et al. reported that NOx concentrations under dual-fuel operations were slightly lower than for normal diesel operations at low engine loads, but considerably lower at high engine loads. The authors also noted that the increase in engine speed under dual-fuel operation resulted in further decreases in NOx concentrations as compared with normal diesel operation.

Figure 2.1: NO Emissions at Various Loads, Engine Speeds and Natural Gas Percentages
(Source: Papagiannakis et al. 2010)

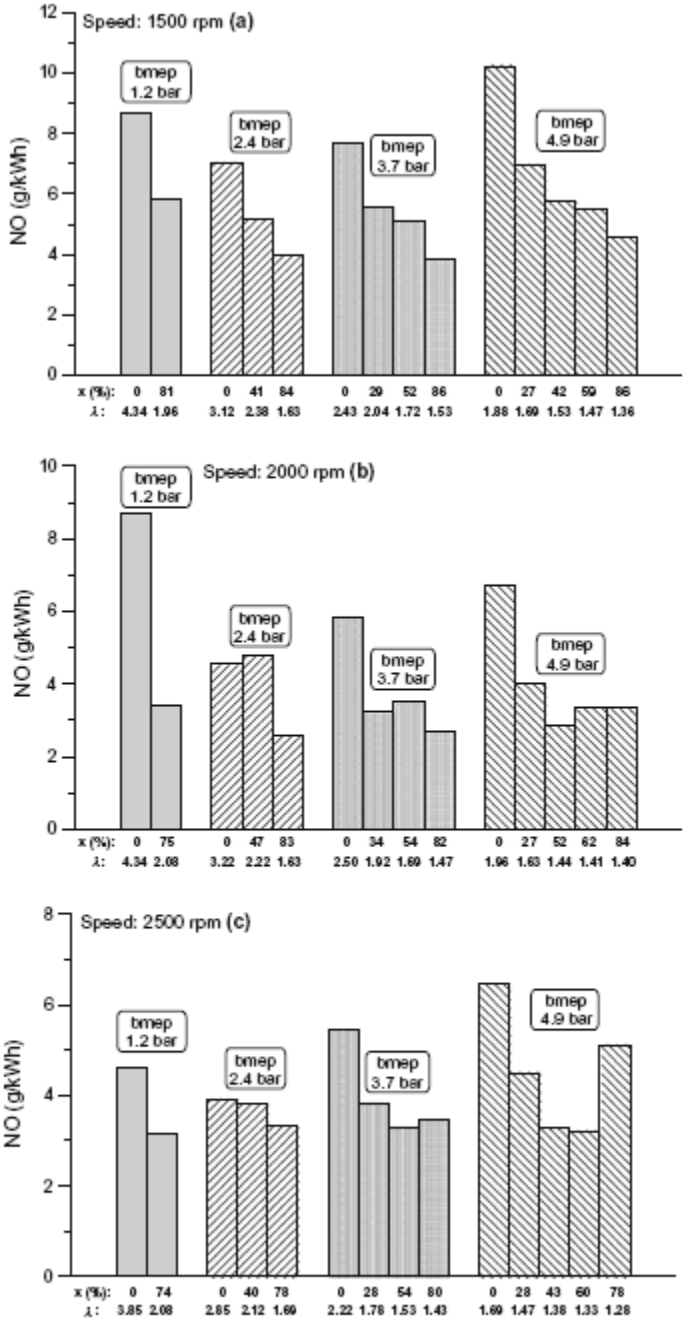


Fig. 4. Bar chart diagram of the emitted specific nitric oxide (NO) at various loads (bmep) as function of the supplementary ratio '*x*' and corresponding total relative air–fuel ratio '*λ*', for the engine speeds of 1500 rpm (a), 2000 rpm (b), and 2500 rpm (c).

Figure 2.2: NOx Emissions for Dual-fuel and Normal Diesel Operation at Various Loads and Engine Speeds (Source: Sahoo et al. 2009)

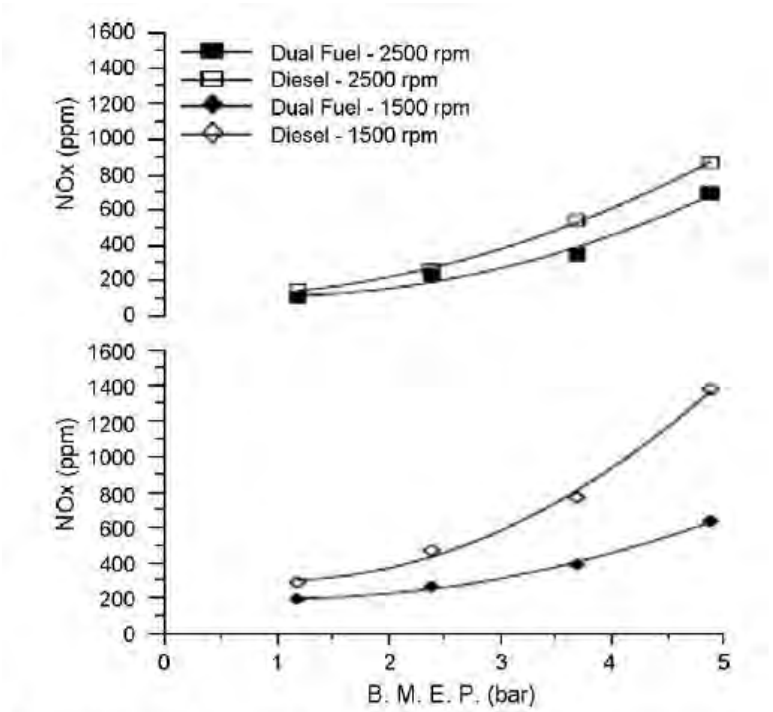


Fig. 10. Variation of nitric oxide under normal diesel and dual-fuel operation versus load at 1500 and 2500 rpm engine speed [19].

2.2 CO EMISSIONS

All published sources considered in this literature review were in agreement that dual-fuel operation results in an increase in CO concentrations in exhaust emissions. The increases are highest at low engine load and low inlet air temperatures, with theoretical maximum increases in CO emissions of up to 600% (Papagiannakis et al. 2010b). Emission increases of 200-300% for dual-fuel operations would be more typical at high engine loads.

According to the R.G. Papagiannakis and D.T. Hountalas (2003) study:

> *"..in general CO emission values under dual fuel operation are considerably higher compared to normal diesel operation."*

Increased CO emissions are a result of the slow combustion rate of the gaseous fuel, *"which maintains the charge temperature at low levels resulting [in] a reduction of the oxidation process of carbon monoxide"*.

However, the study does note that with high engine loads (80% load), as mass ratios of natural gas increase above ~50%, CO emissions begin to decrease. This reduction is assumed to be the result of higher gas temperatures and faster combustion rates.

In Papagiannakis et al. (2010), tests showed that:

> *"for the same operating point (i.e., engine speed and load) CO emissions under dual fuel operation are significantly higher compared to the respective [emissions] under normal diesel operations."*

According to the 2010 study, and as indicated in Figure 2.3, this effect is more pronounced at low loads where the increase of CO emissions can be up to 600%. At intermediate loads, the maximum increase in CO emissions is up to 270%. At high engine loads and low engine speeds, the maximum increase in CO emissions is only 70% compared to that under normal diesel only operations.

Based on a third study performed by Papagiannakis et al. (2010b):

> *"..the negative impacts of dual fuel operation on CO emissions could be curtailed by preheating air intake and increasing pilot fuel quantity as well. However, this appears to affect negatively NO emissions with the effects* [becoming] *more intense at high engine load. Thus from the viewpoint of pollutant emissions, the increase of the pilot fuel quantity has to be accompanied by a limited increase of intake air temperature."*

Figure 2.3: CO Emissions at Various Loads, Engine Speeds and Natural Gas Percentages (Source: Papagiannakis et al. 2010)

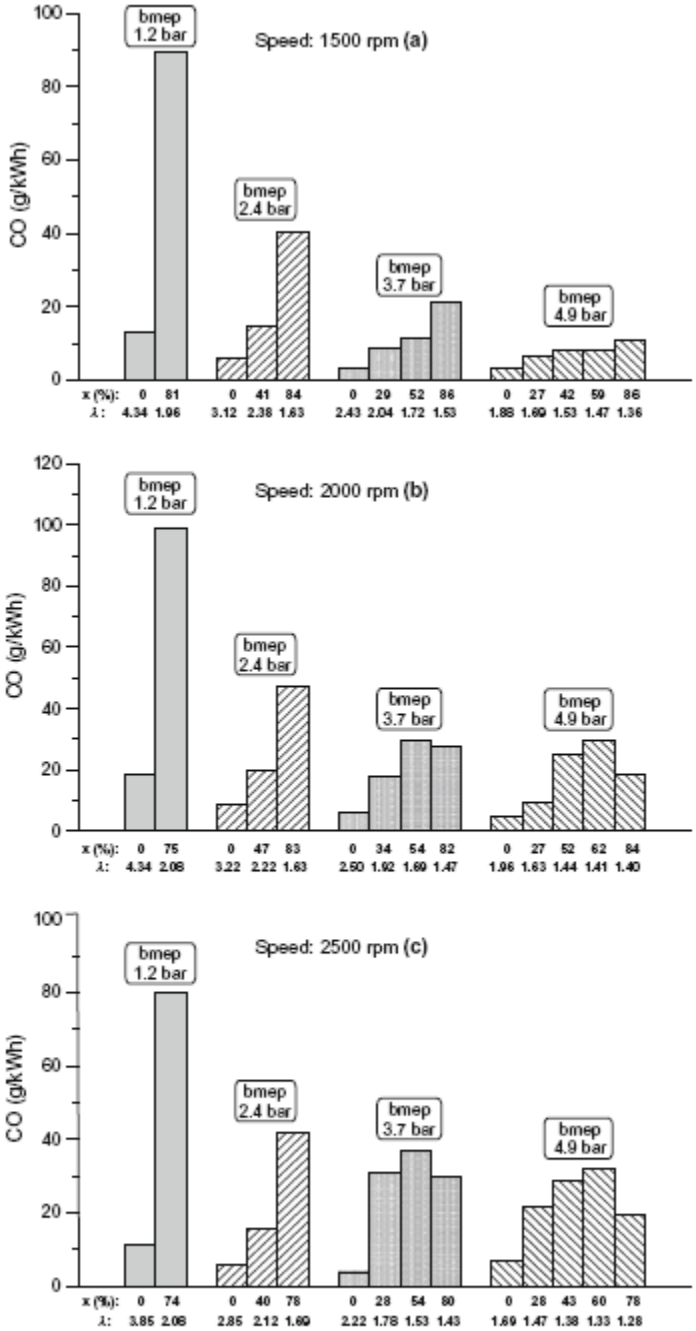


Fig. 5. Bar chart diagram of the emitted specific carbon monoxide (CO) at various loads (bmep) as function of the supplementary ratio 'x' and corresponding total relative air–fuel ratio 'λ', for the engine speeds of 1500 rpm (a), 2000 rpm (b), and 2500 rpm (c).

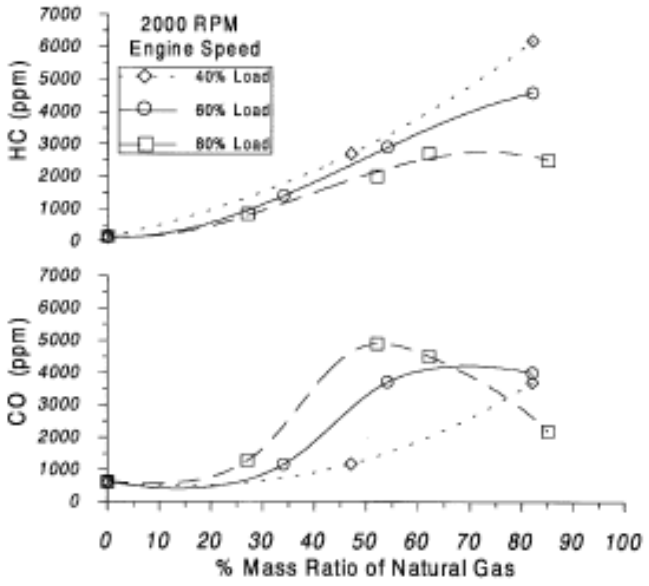
2.3 UNBURNED HC EMISSIONS

Emissions of unburned hydrocarbons can be expected to increase in dual-fuel mode operations as compared with diesel only operations. Papagiannakis and Hountalas (2003) showed that as the fractional mass ratios of natural gas increases in the fuel feed to the engine, unburned HC emissions increase for all load levels. The study speculated that this increase was caused by:

> *"..the filling of crevice volumes with unburned mixture of air and gaseous fuel during compression and combustion while the cylinder pressure continues to rise".*

Figure 2.4 indicates that, at low engine loads (i.e., 40% load factor), HC emissions increase with the increasing percentage of natural gas added to the dual fuel mix. As the load factor increases, the emission of unburned HC decreases somewhat, but always remains greater than that for normal diesel only operations. The magnitude of the increase may range from a 2500 fold increase at high load factor above the level and 70% natural gas ratio to over 6000 times that of diesel only operations at low load and 80% natural gas ratio.

Figure 2.4: Unburned HC and CO Concentrations as a Function of Natural Gas Ratio for Various Engine Loads (Source: Papagiannakis and Hountalas 2003)



The authors reported that in the high load scenario, the slight decrease in unburned HC emissions for the high load factor scenario observed after ~70% natural gas ratio is minimal. The slight decrease is attributed to higher burnt gas temperatures which promote oxidation of unburned

hydrocarbons. These results were confirmed by Papagiannakis et al. (2010) who showed that the difference is *"more intense at low load conditions, thus revealing the considerable amount of gaseous fuel escaping the combustion process."* This is illustrated in Figure 2.5 below.

Figure 2.5: Unburned HC Emissions at Various Loads, Engine Speeds and Natural Gas Percentages (Source: Papagiannakis et al. 2010)

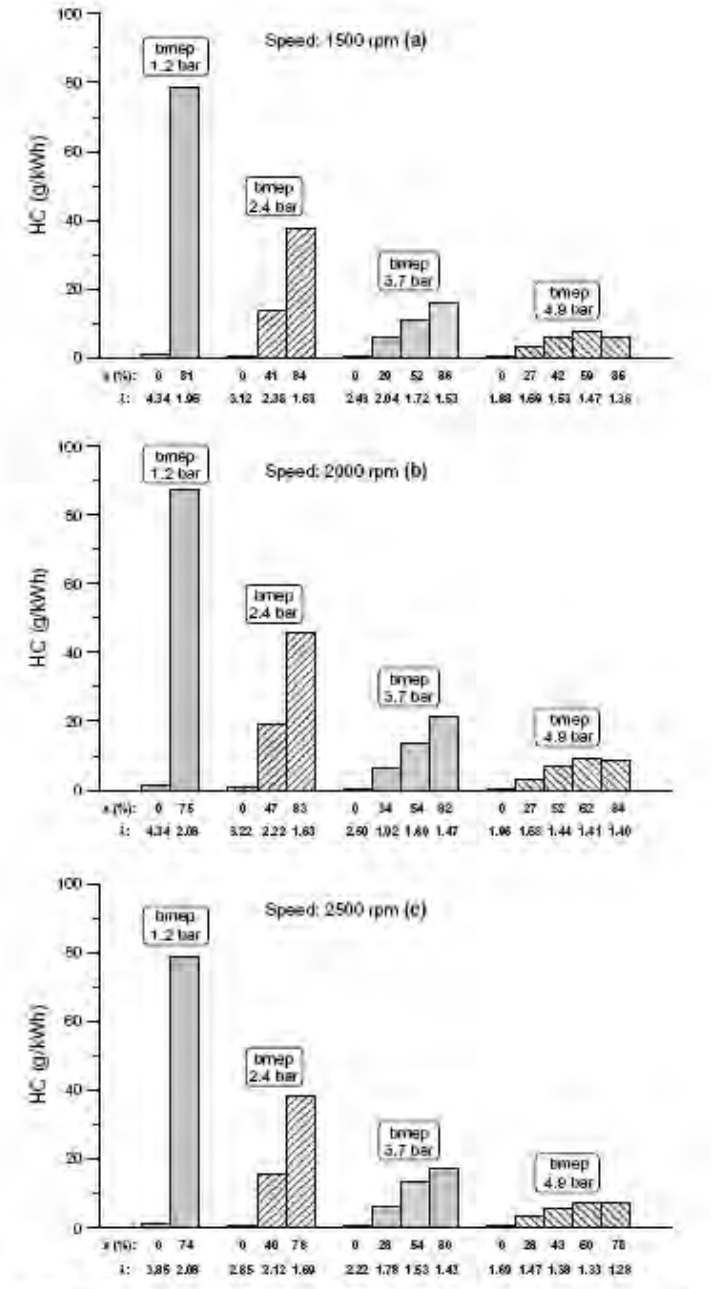
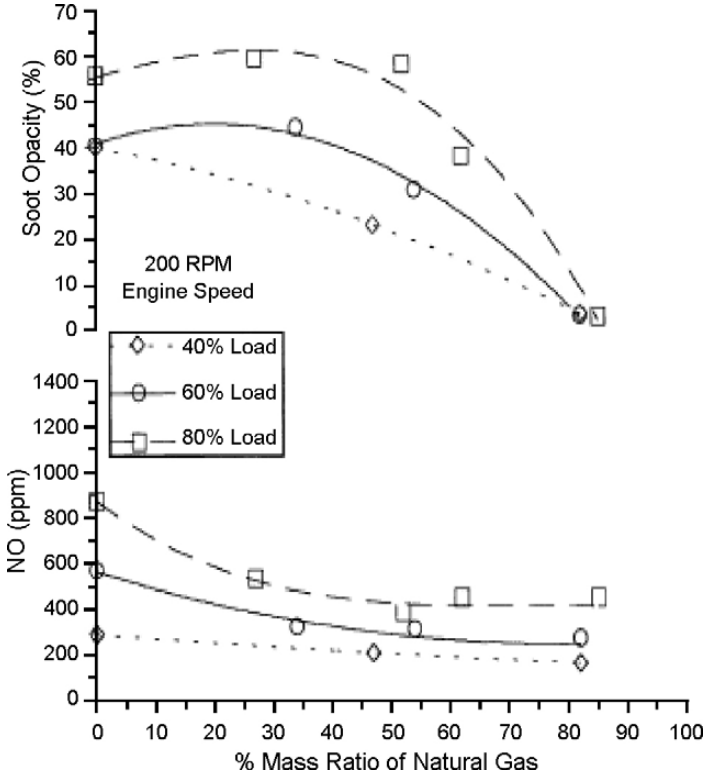


Fig. 6. Bar chart diagram of the emitted specific unburned hydrocarbons (HC) at various loads (bmep) as function of the supplementary ratio 'x' and corresponding total relative air–fuel ratio 'λ', for the engine speeds of 1500 rpm (a), 2000 rpm (b), and 2500 rpm (c).

2.4 PARTICULATE MATTER (PM) OR SOOT

Dual-fuel operation results in substantially lower PM emissions as compared with normal diesel only operations, and this effect is greatest at high engine loads and near stochiometric air-fuel ratios (Papagiannakis et al. 2010). This is illustrated in Figure 2.6.

Figure 2.6: Soot Opacity and NO Concentration as a Function of Natural Gas Ratio for Various Engine Loads (Source: Papagiannakis and Hountalas 2003)



Papagiannakis and Hountalas (2003) observed that soot production decreases at partial load factors as the percent mass ratio of natural gas increases. At higher loads and low percent mass ratios, soot initially increases (as the charge temperature is inferior to pure diesel operation), but then begins to decrease as the percent mass ratio of natural gas increases further. According to the authors: *"This is probably due to the higher gas temperature that promotes soot oxidation rate contributing to a further decrease of soot concentration"*. This is corroborated by Papagiannakis et al. (2010), however it was also reported in the latter study that, at high engine loads and an engine speed of 2000 rpm, an increase in PM emissions was noted between 27% and 52% natural gas, which was then reduced once more as the percentage of natural gas was increased further.

Figure 2.7: Soot emissions at Various Loads, Engine Speeds and Natural Gas Percentages (Source: Papagiannakis et al. 2010)

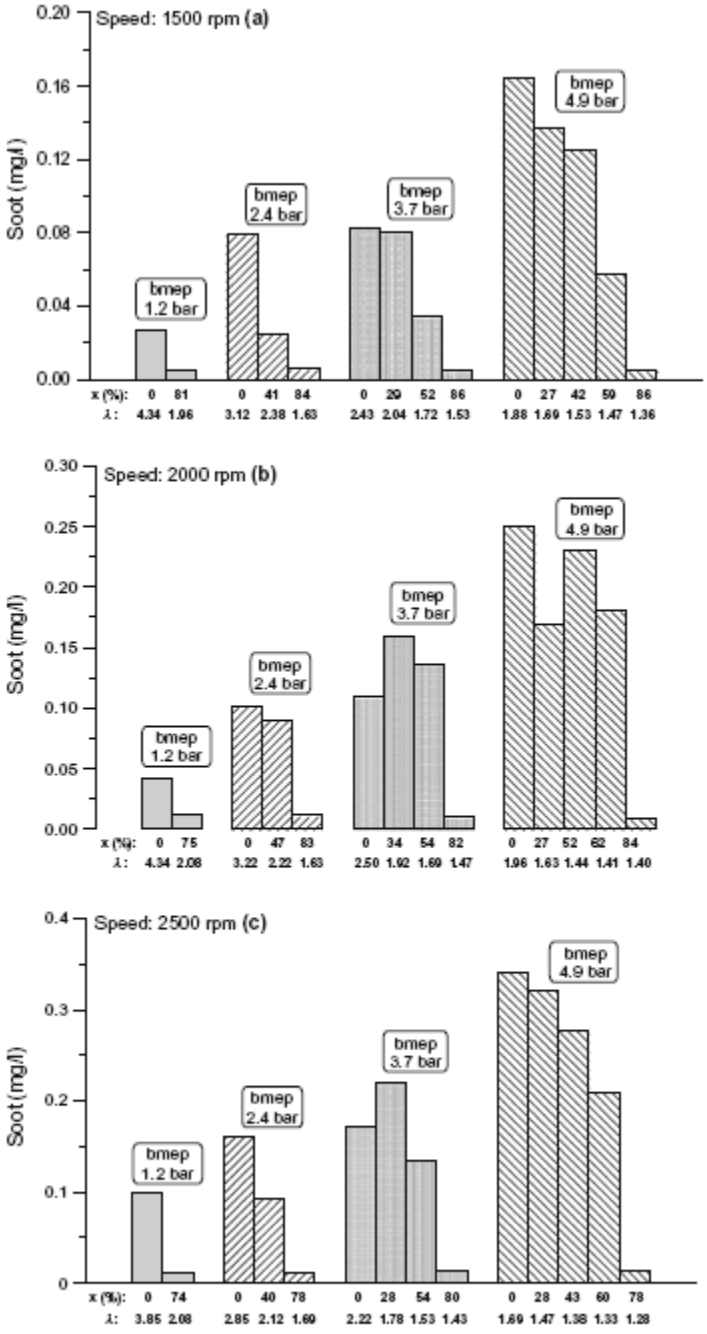


Fig. 7. Bar chart diagram of the emitted soot (smoke) density at various loads (bmep) as function of the supplementary ratio 'x' and corresponding total relative air–fuel ratio 'λ', for the engine speeds of 1500 rpm (a), 2000 rpm (b), and 2500 rpm (c).

2.5 CONTROLLED FUELLING

A study conducted by Abdelghaffar (2011) examined the effect of dual-fuel versus controlled dual-fuel operation modes on air emissions. In controlled dual-fuel mode, the amount of diesel fuel injected into the engine with the natural gas is manually controlled. Experiments showed that while emissions of CO and HC increased in dual-fuel mode, the emission increases can be reduced if the amount of diesel fuel injected into the engine is controlled. Controlled fuel injection also decreases NOx emissions.

3.0 CONCLUSIONS

The overall conclusion of the literature review is that emissions of NOx and PM from the pilot scale testing of one unit at the Watson Lake generating station would be expected to decrease in dual-fuel mode operation, while emissions of CO and unburned HC would be expected to increase. SO_2 emissions are a function of the amount of sulphur in the fuel fed to the engine. As such, any decrease in the overall amount of sulphur in dual-fuel operation as compared with diesel only operation will result in a proportional decrease in SO_2 emissions.

Table 3.1 lists the maximum predicted concentrations of common air contaminants for emissions from the six generating units at the YECL Watson Lake generating station based on diesel fuel operation. The data indicate that the incremental contribution (i.e., excluding background air quality from other sources) of YECL emissions to ambient air quality levels in Watson Lake is well below the ambient air quality standards that were adopted for the Yukon in 2010. The highest contributions are for 24-hour average $PM_{2.5}$ and 1-hour average NO_2 concentrations. Under dual-fuel operation, the emission of both of these contaminants would be expected to decrease further. The YECL contribution to SO_2 concentrations is marginal, such that any changes in SO_2 emissions would have no measurable effect on ambient air concentrations.

Table 3.1: Summary of Maximum Predicted Concentrations for Simultaneous Operation of Six Diesel Engines at the YECL Watson Lake Generating Station

Pollutant	Timeframe	Maximum Predicted Concentration[1] µg/m^3	Yukon Standards µg/m^3	% of Yukon Standard
NO_2	1 Hour	88.40	400	22.1%
	24 Hour	26.77	200	13.4%
	Annual	1.44	60	2.4%
$PM_{2.5}$	24 Hour	8.81	30	29.4%
SO_2	1 Hour	1.86	450	0.4%
	24 Hour	0.77	150	0.5%
	Annual	0.04	30	0.1%
CO	1 Hour	333.85	15000	2.2%

[1] excluding background concentrations

However, as discussed in Section 2.2 above, CO emissions may increase substantially for dual fuel operations over current diesel only operations. The increase may be on the order of 200-270% under intermediate engine load operations, to as much as 600% increase at low engine load operations. At high engine load operations, the increase in CO emissions would be lower at only about 70% as compared with diesel only operations. Because the data in Table 3.1

represent the joint contributions assuming the operation of all six units at the Watson Lake generating station, a 600% increase in CO emissions from the one unit undergoing dual-fuel pilot testing will not result in a concomitant 600% increase in the incremental impact of CO emissions from the station as a whole. Assuming an equal contribution from all six units to the maximum predicted 1-hour average CO concentration of 333.85 $\mu g/m^3$, a 600% increase in CO emissions from the one dual-fuel pilot test unit would result in a maximum 1-hour average CO concentration of 612.06 $\mu g/m^3$, or a factor 1.8 increase over the total CO concentration from all six units running on diesel alone. This would represent 4.1% of the Yukon ambient air quality standard for 1-hour average CO concentrations.

Although the emission of unburned hydrocarbons is likely to increase under dual-fuel operation more than for any other contaminant, the emission of these compounds is relatively low under diesel only operations. The primary HC contaminant of potential concern would be benzene. The increase in HC emissions will amount to a relatively large increase of small initial quantities. There are no Yukon ambient air quality standards for any of the HC contaminants whose emissions are likely to increase.

4.0 REFERENCES

Abdelghaffar, W.A. (2011). *Performance and Emissions of a Diesel Engine Converted to Dual Diesel-CNG Fuelling*. European Journal of Scientific Research, 56 (2): 279-293.

Papagiannakis, R.G., Hountalas, D.T. (2003). *Experimental investigation concerning the effect of natural gas percentage on performance and emissions of a DI dual fuel diesel engine.* Applied Thermal Engineering, 23: 353-365.

Papagiannakis, R.G., Rakopoulos, C.D., Hountalas, D.T., Rakopoulos, D.C. (2010) *Emission characteristics of high speed, dual fuel, compression ignition engine operating in a wide range of natural gas/diesel fuel proportions.* Fuel. 89: 1397-1406.

Papagiannakis, R.G., Kotsiopoulos, P.N., Zannis, T.C., Yfantis, E.A., Hountalas, D.T., Rakopoulos, C.D. (2010b). *Theoretical study of the effects of engine parameters on performance and emissions of a pilot ignited natural gas diesel engine.* Energy, 35: 1129-1138.

Sahoo, B.B., Sahoo, N., U.K. Saha (2009). *Effect of engine parameters and type of gaseous fuel on the performance of dual fuel gas diesel engines – A critical review.* Renewable and Sustainable Energy Reviews, 13: 1151-1184.

YCS-YECL-2-2

Reference: Watson Lake Bi-Fuel Project

"Phase 1 of the project (2013) involves the modification of Watson Lake power plant generation unit #5 to a bi-fuel system, which allows the unit to run on a combination of diesel and natural gas. The purpose of this phase is to verify that NG injection into the engine provides reliable electricity generation for a utility power system along with the environmental benefit to reduce emissions."

Request:

Please explain in detail how YECL plans to measure and report on the changes in various emissions in this bi-fuel project compared to the diesel plants in Phase 1.

Response:

At this time, Yukon Electrical has received direction from the Decision Body on the application for this project to the Yukon Environmental and Socio-economic Assessment Board (YESAB), which provides guidance on emissions testing protocols and reporting requirements. Yukon Electrical is currently assessing these requirements.

In the project submission and subsequent Information Requests, Yukon Electrical submitted to YESAB that emissions from exhaust stack of the first unit conversion, or Phase 1, will be tested to better understand the emissions performance results. Emissions testing will be conducted on Unit # 5, the first unit to be converted as part of Phase 1 of the pilot project. Testing will be performed while the unit is utilizing 100% diesel fuel as well as in bi-fuel operating mode.

YCS-YECL-2-3

Reference: Watson Lake Bi-Fuel Project

"The availability of LNG allows for reduced emissions in existing generating units through the displacement of diesel fuels." In terms of greenhouse gas emissions, it is understood that methane has a far greater global warming potential (GWP) than Carbon Dioxide CO2. Unburned methane from incomplete combustion will result in more methane-based GHG emissions. This is significant especially when considering methane's potency over a 20-year time frame (GWP = 72 CO2e) or even over a 100-year time frame (GWP = 25 CO2e). It is accepted by the scientific community that we don't, in fact, have anywhere near 100 years to meet the challenge of the climate crisis. We need to break our dependency on fossil fuels immediately and not release methane into the atmosphere.

Request:

Please provide peer-reviewed reference documentation and describe the basis of your assumption that burning LNG with diesel rather than exclusively diesel will result in reduced emissions.

Response:

The primary driver for the Watson Lake Bi-Fuel project is to provide local emissions reductions. It is predicted that there will be a reduction in particulate matter (PM) emissions, important to people with compromised lung function, and NOx and SOx, contributing to smog and acid rain.

Please refer to YCS-YECL-2-1 for peer-reviewed information.

YCS-YECL-2-4

Reference: Watson Lake Bi-Fuel Project

"In addition to the environmental benefits of this project to reduce emissions of particulate matter, sulfur oxides, nitrogen oxides and carbon dioxide, this initiative will assist in determining the operational and financial benefits of the use of LNG as an alternate fuel for electricity generation."

Request:

Please describe any potential negative environmental impacts or increased emissions from burning an LNG/diesel mix in terms of emissions (i.e., Carbon Monoxide, Volatile Organic Compounds, such as carcinogenic benzene) and provide the source of this information.

Response:

By chemical composition, natural gas is known to result in fewer environmental emissions than diesel for species of note: particulate matter (PM), NO_x, and SO_2.

A bi-fuel system can have different characteristics than a unit which uses 100% natural gas or 100% diesel. In December 2012 SENES (please refer to YCS-YECL-2-1 Attachment 1 for *Literature Review: Air Contaminant Emissions from Dual-Fuelled and Conventional Diesel Generator Operations*) completed a literature study to summarize existing information on air contaminant emissions for bi-fuel systems and used this information to predict how previously modeled air emissions are affected by the proposed bi-fuel modification of one engine in the power plant. SENES concluded that emission levels for nitrogen oxide (NO_x), particulate matter (PM) or soot, and sulphur dioxides (SO_2) are expected to decrease, while emissions of unburned hydrocarbons (HC) and carbon monoxide (CO) are expected to increase. The increase in CO, however, is expected to remain well below Yukon air quality standards. There are no Yukon standards that apply to the HC that are expected to be emitted; the actual quantities are expected to be low.

As submitted by Yukon Electrical on February 15, 2013 in response to a request for information from the Yukon Environmental and Socio-economic Assessment Board (YESAB):

> The U.S. Environmental Protection Agency's (USEPA) AP-42 compilation of emission factors Section 3.4 on emissions from Large Stationary and All Stationary Dual-fuel Engines provides information on unburned hydrocarbons from one diesel-fuel engine, and an emission factor for Total Organic Carbon (TOC) from one dual-fuel engine. There was no speciated emission data from any of the other published literature sources reviewed in the SENES [2012] report on bi-fuel engines. (Note: the terms dual-fuel and bi-fuel are used interchangeably in the literature).

There is a lack of publicly available information on bi-fuel operations to be able to provide an accurate predictor of the change in unburned hydrocarbon emissions between diesel and bi-fuel operations. Furthermore, as emissions of CO_2, CO, NO_x and unburned HCs in the combustion products are engine specific, the details of emissions will not be fully understood until the project is in operation and emissions sampling and analysis is complete.

YCS-YECL-2-5

Reference: Watson Lake Bi-Fuel Project

"Phase II will be undertaken if phase 1 is successful."

Request:

Please describe in detail how YECL defines success of Phase 1.

Response:

Phase 1 of the Watson Lake Bi-Fuel Project will evaluate the ability of Unit #5 (the first unit to be converted to bi-fuel operation in Phase 1) to operate safely and reliably, and also to demonstrate that the project meets emissions requirements. In addition, the initial phase of the project will provide insight into the viability of a natural gas supply chain.

YCS-YECL-2-6

Reference: Watson Lake Bi-Fuel Project

"Business Drivers" states that a primary objective of this project is to reduce emissions from the production of electricity, particularly in light of increased reliance on diesel. And "Deliver an environmental benefit to the community of Watson Lake through the reduction of emissions of particulate matter, Sox, NOx, and CO2."

Request:

Please explain why YECL is claiming an environmental benefit to the community of Watson Lake when it is predicted that Carbon Monoxide (CO) emissions and unburned hydrocarbons/Volatile Organic Compounds will significantly increase from burning LNG with diesel.

Response:

A primary driver for the Watson Lake Bi-Fuel project is to provide local emissions reductions through the displacement of diesel. It is predicted that there will be a reduction in CO_2, particulate matter (PM) emissions, important to people with compromised lung function, and NOx and SOx, contributing to smog and acid rain.

At this time, there is no reason for Yukon Electrical to believe that Carbon Monoxide (CO) emissions and unburned hydrocarbons (HC)/Volatile Organic Compounds will increase beyond regulated levels from bi-fuel (natural gas and diesel) combustion. An increase in Carbon Monoxide from bi-fuel combustion in the order of 2 to 6 times that of diesel-only operation is dependent on the loading level of individual generating units. The present emission level of CO is approximately 2.2% of the Yukon standard for concentration. The resultant increase is below Yukon standards and the actual quantities are expected to be low.

For further discussion on this, please refer to YCS-YECL 2-1.

YCS-YECL-2-7

Reference: Watson Lake Bi-Fuel Project

"Business Drivers" states that a primary objective of this project is to reduce emissions from the production of electricity, particularly in light of increased reliance on diesel. And "Deliver an environmental benefit to the community of Watson Lake through the reduction of emissions of particulate matter, SOx, NOx, and CO2."

Request:

If a primary driver of this project is reducing emissions from the production of electricity, please describe your understanding of the life cycle emissions and pollution from the extraction, processing, liquefaction and transportation of LNG and diesel. Please provide references.

Response:

Project proponents conducted an internal life cycle CO_2 estimate of the total emissions of a liquefied natural gas scenario, using emission factors from the "2012 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions" and Environment Canada. The estimate takes into account emissions attributable to the extraction & processing of the natural gas, its liquefaction & transportation from Delta, B.C. to Watson Lake, Yukon, and its combustion on site. This scenario was then compared to a baseline which takes into account the emissions attributable to the production of diesel, its transportation from Edmonton, Alberta to Watson Lake, Yukon, and its combustion on site.

The estimate revealed that upon full LNG project implementation (all engines on site converted to bi-fuel), the CO_2 savings would be on the order of 20% for every GJ of diesel fuel displaced.

For additional information, please refer to the reference in YUB-YECL-42(f).

YCS-YECL-2-8

Reference: Watson Lake Bi-Fuel Project

"Business Drivers" states that a primary objective of this project is to reduce emissions from the production of electricity, particularly in light of increased reliance on diesel. And "Deliver an environmental benefit to the community of Watson Lake through the reduction of emissions of particulate matter, Sox, NOx, and CO2."

Request:

If a primary driver is reducing emissions from the production of electricity, please describe any efforts YECL has made in Watson Lake and its other diesel-powered communities to reduce the overall consumption of fossil fuel generated electricity.

Response:

A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed in 2010 with a levelized cost of electricity estimated at 50 cents/kWh. Yukon Electrical is participating in a hydroelectric study to provide long-term renewable electricity for the Watson Lake electrical system. Yukon Electrical is participating in a geothermal energy study as an additional long term renewable alternative. Yukon Electrical assisted with integration of solar Photo Voltaic generating capacity into the community of Old Crow. Yukon Electrical is proposing Demand Side Management initiatives for electricity conservation that is applicable to diesel communities and is co-participating in development of a Net Metering Policy for customers to self-generate utilizing renewable technologies.

YCS-YECL-2-9

Reference: Watson Lake Bi-Fuel Project

Section 4 – fuel costs pages 4-1 and 4-2 states that: "Beginning in 2013, a supply of Liquid Natural Gas (LNG) for the Watson Lake power plant will be sourced from Fortis B.C. Page 4-3 states: For the usage of LNG in Watson Lake, fuel costs will be converted to equivalent Diesel litres using the following industry standard conversion factors for LNG for the calculation of the fuel price flow through deferral balance: LNG Energy Content of Diesel 58%. Page 5-5 states: Beginning in the fall of 2013, Yukon Electrical will be leasing liquid natural gas (LNG) storage and vaporization equipment from an affiliate company, ATCO Gas, related to the Watson Lake Bi-Fuel project."

Request:

Please explain why this project is necessary and why now.

Response:

This project is necessary to advance community and Yukon Electrical objectives for reducing emissions from diesel generating sources while longer term solution technologies such as hydro, wind and geothermal are being advanced.

Other technologies face significant challenges with respect to their higher cost of electricity and/or the time required to implement. Natural gas provides the capability to meet firm power capacity requirements in addition to straight energy displacement. Natural gas has been identified as having the potential to generate lower cost power with lower overall emissions.

Relatively simple technology exists to modify stationary reciprocating diesel engines so that they can use supplemental amounts of natural gas without the need to invest the capital cost of new generating units.

The availability of LNG offers a viable means to provide natural gas to communities that are not on a gas pipe system and provides fuel diversity.

This project advances Yukon Electrical's on-going commitment to meet the growing energy requirements of the Yukon. This project also advances a strategic objective to provide the lowest cost electrical production possible to the residents of the Yukon, in an environmentally sound manner. The Watson Lake project will allow Yukon Electrical

to continue its commitment to these objectives at existing diesel power plants and possible future power plants in the Yukon.

YCS-YECL-2-10

Reference: Watson Lake Bi-Fuel Project

Section 4 – fuel costs pages 4-1 and 4-2 states that: "Beginning in 2013, a supply of Liquid Natural Gas (LNG) for the Watson Lake power plant will be sourced from Fortis B.C. Page 4-3 states: For the usage of LNG in Watson Lake, fuel costs will be converted to equivalent Diesel litres using the following industry standard conversion factors for LNG for the calculation of the fuel price flow through deferral balance: LNG Energy Content of Diesel 58%. Page 5-5 states: Beginning in the fall of 2013, Yukon Electrical will be leasing liquid natural gas (LNG) storage and vaporization equipment from an affiliate company, ATCO Gas, related to the Watson Lake Bi-Fuel project."

Request:

Please describe in detail the anticipated cost savings (including all assumptions and calculations) from burning a combination of LNG/diesel as opposed to exclusively diesel.

Response:

Please refer to YUB-YECL-42(a) for the anticipated cost savings related to the Watson Lake Bi-Fuel Project.

YCS-YECL-2-11

Reference: Watson Lake Bi-Fuel Project

Section 4 – fuel costs pages 4-1 and 4-2 states that: "Beginning in 2013, a supply of Liquid Natural Gas (LNG) for the Watson Lake power plant will be sourced from Fortis B.C. Page 4-3 states: For the usage of LNG in Watson Lake, fuel costs will be converted to equivalent Diesel litres using the following industry standard conversion factors for LNG for the calculation of the fuel price flow through deferral balance: LNG Energy Content of Diesel 58%. Page 5-5 states: Beginning in the fall of 2013, Yukon Electrical will be leasing liquid natural gas (LNG) storage and vaporization equipment from an affiliate company, ATCO Gas, related to the Watson Lake Bi-Fuel project."

Request:

Please describe the methodology and assumptions used in projecting future costs of LNG, especially in light of planned export LNG facilities in BC enabling currently landlocked fossil fuel resources to reach and compete in the global market, where natural gas prices are significantly higher. Please provide financial scenarios for LNG costs doubling, tripling or quadrupling due to LNG exports. How will those future cost scenarios affect the predicted cost effectiveness of LNG bi-fuel?

Response:

Export projects are anticipated only to proceed given a wide price differential between "global" and North American natural gas prices. As the LNG market matures, contracts are trending towards "natural gas plus" instead of "petroleum minus", and they are becoming of shorter duration (a "spot" LNG market may eventually develop). Therefore, a major decrease in price differential (i.e. an increase in North American natural gas pricing) will lead to a reduction in exports, and a subsequent reduction in pricing pressure for North America. This "high price cure for high prices" effect is well known and observed in almost all mature and healthy commodity markets.

Furthermore, natural gas commodity is only approximately 20% of the overall cost of LNG delivered to Watson Lake. Therefore, a quadrupling of the cost of natural gas (400%) will only increase the cost of LNG by 60%. (In comparison, unrefined oil makes up 50% of the overall cost of diesel and, therefore, diesel is much more sensitive to commodity price increases).

Note that LNG can also provide Yukon Electrical with greater cost certainty in that commercial natural gas contracts can currently be locked in for up to 5 years. In comparison, diesel contracts are typically shorter term. Furthermore, bi-fuel systems allow Yukon Electrical to use greater or lesser amounts of each type of fuel depending on pricing conditions.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-3-1

Reference: Automated Meter Reading

"Capital meter additions include new meters that are required to replace obsolete or end of life meters as identified by measurement Canada. For 2010 and forward, this also includes the installation of new meters required to accommodate load growth associated with customer requests for service. Prior to 2010, these meters were grouped with new extensions. These expenditures allow Yukon Electrical to meet its obligation to provide metered service connections. The capital meter additions are forecasted based on known areas of development and expected connection requests."

Request:

Please explain how these new meters will or will not have the technological capability to accommodate load management (peak shaving and load shifting) programs such as time-of-use pricing and utility- or customer-controlled appliances (such as hot water heaters).

Response:

The TWACS meters do have an optional ability to incorporate utility-controlled devices that can communicate and control customer equipment and appliances. This optional ability is not included in Yukon Electrical's business case at this time. The time of use ability of the TWACS meters is not currently Measurement Canada approved for revenue metering. Yukon Electrical intends on utilizing the time of use capability of the TWACS meters for system load studies.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-3-2

Reference: Automated Meter Reading

"Capital meter additions include new meters that are required to replace obsolete or end of life meters as identified by measurement Canada. For 2010 and forward, this also includes the installation of new meters required to accommodate load growth associated with customer requests for service. Prior to 2010, these meters were grouped with new extensions. These expenditures allow Yukon Electrical to meet its obligation to provide metered service connections. The capital meter additions are forecasted based on known areas of development and expected connection requests."

Request:

Please explain how these new meters will or will not have the technological capability to accommodate net-metering programs (customer generated energy for consumption and surplus sales back to the grid).

Response:

These AMR meters will not have net metering capability. However, Yukon Electrical has addressed the need for net metering in a current pilot project and will be able to accommodate a future net metering policy. Yukon Electricl is currently able to provide a net meter that requires manual reading.

YCS-YECL-3-3

Reference: Automated Meter Reading

"Capital meter additions include new meters that are required to replace obsolete or end of life meters as identified by measurement Canada. For 2010 and forward, this also includes the installation of new meters required to accommodate load growth associated with customer requests for service. Prior to 2010, these meters were grouped with new extensions. These expenditures allow Yukon Electrical to meet its obligation to provide metered service connections. The capital meter additions are forecasted based on known areas of development and expected connection requests."

Request:

If the proposed new meters will not accommodate DSM, load management and net metering programs, please explain why.

Response:

For information regarding load management, please refer to the response to information request YCS-YECL-3-1.

For information regarding net metering, please refer to the response to information request YCS-YECL-3-2.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-4-1

Reference: Old Crow Plant Expansion and Unit #3 Replacement

Request:

Please describe any attempts or investments that YECL has made (i.e., partnerships and or discussions with Yukon Government and or Vuntut Gwitchin Government, studies, pilot projects, etc.) to supplement the exclusive fossil fuel-generated electricity in this community with solar, wind or any other renewable energy option to reduce greenhouse gas emissions and other pollution associated with burning fossil fuels.

Response:

A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed in 2010 with a levelized cost of electricity estimated at 50 cents/kWh. The selected study location was deemed to be one of the most attractive from a wind resource perspective of the communities served by Yukon Electrical. The community of Old Crow was viewed as a more challenging location that would be developed after.

Yukon Electrical assisted with the integration of solar Photo Voltaic generating capacity into the community of Old Crow.

Yukon Electrical visited the community of Old Crow in June 2011 and met with Vuntut Gwitchin Chief and Council as well as held a public information session to discuss electricity conservation, potential opportunities and the efforts related to Demand Side Management.

Yukon Electrical is co-participating in development of a Net Metering Policy for customers to self-generate utilizing renewable technologies that will be applicable to the community. Yukon Electrical is participating in a hydroelectric study and a geothermal energy study that may provide long-term renewable opportunities for the community of Old Crow.

YCS-YECL-4-2

Reference: Old Crow Plant Expansion and Unit #3 Replacement

Request:

Please describe any efforts made by YECL to help customers reduce consumption of electricity therefore reducing the combustion of fossil fuels to reduce costs and emissions, in all communities that YECL services exclusively with diesel.

Response:

A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed in 2010. The selected study location was deemed to be one of the most attractive from a wind resource perspective of the communities served by Yukon Electrical. The results of this study are applicable to other communities served by Yukon Electrical diesel generating units.

Yukon Electrical assisted with the integration of solar Photo Voltaic generating capacity into the community of Old Crow.

Yukon Electrical visited a number of communities in 2011 and 2012 to discuss electricity conservation, potential opportunities and the efforts related to demand side management.

Yukon Electrical participated in a technical evaluation to assist the community of Destruction Bay/Burwash Landing as they look to implement energy monitoring and management opportunities for the community that may also be applicable to other northern communities.

Yukon Electrical participated in the Community Energy and Emissions Inventory study for Kluane First Nation – Yukon Research Centre Partnership Project.

Yukon Electrical participated in an Energy Summit conference in March, 2013 held by the Kluane First Nation.

Yukon Electrical is co-participating in development of a Net Metering Policy for customers to self-generate utilizing renewable technologies that will be applicable to communities. In preparation for the government approval of the net metering policy,

Yukon Electrical is piloting the first net-metering project in the community of Burwash Landing.

Yukon Electrical is participating in a hydroelectric study and a geothermal energy study that may provide long-term renewable opportunities for the communities served by Yukon Electrical.

Yukon Electrical provides presentations at the Association of Yukon Communities related to energy conservation opportunities.

As part of the Conservation Potential Review and development of the Demand Side Management Plan, Yukon Electrical has met in various communities and discussed efficiency and conservation opportunities with many stakeholders.

YCS-YECL-5-1

Reference: Beaver Creek Unit #1 and #2 Replacement

Request:

Please describe any attempts or investments that YECL has made (i.e., partnerships and or discussions with Yukon Government and or White River First Nation, studies, pilot projects, etc.) to supplement the exclusive fossil fuel-generated electricity with solar, wind or any other renewable energy option to reduce greenhouse gas emissions and other pollution associated with burning fossil fuels.

Response:

Please refer to YCS-YECL-4-2.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-6-1

Reference: Destruction Bay Unit #2 Replacement

Request:

Please describe any attempts or investments that YECL has made (i.e., partnerships and or discussions with Yukon Government and or Kluane First Nation Government, studies, pilot projects, etc.) to supplement the exclusive fossil fuel-generated electricity in this community with solar, wind or any other renewable energy option to reduce greenhouse gas emissions and other pollution associated with burning diesel fuel to generate electricity.

Response:

A feasibility study for a wind-diesel system at Destruction Bay/Burwash Landing was completed in 2010. The selected study location was deemed to be one of the most attractive from a wind resource perspective of the communities served by Yukon Electrical.

Yukon Electrical participated in a technical evaluation to assist the community of Destruction Bay/Burwash Landing as they look to implement energy monitoring and management opportunities for the community that may also be applicable to other northern communities.

Yukon Electrical participated in the Community Energy and Emissions Inventory study for Kluane First Nation – Yukon Research Centre Partnership Project.

Yukon Electrical participated in an Energy Summit conference in March, 2013 held by the Kluane First Nation.

Yukon Electrical is co-participating in development of a Net Metering Policy for customers to self-generate utilizing renewable technologies that will be applicable to communities. In preparation for the government approval of the net metering policy, Yukon Electrical is piloting the first net-metering project in the community of Burwash Landing.

As part of the Conservation Potential Review and development of the Demand Side Management Plan, Yukon Electrical has met in various communities and discussed efficiency and conservation opportunities with many stakeholders.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YCS-YECL-7-1

Reference: Demand Side Management Plan

Request:

Please describe all internal DSM projects that the utilities have undertaken or plan to undertake to reduce their overall consumption of electricity in their operations, or to shift their consumption away from peak times.

Response:

Yukon Electrical continues to make internal system efficiency improvements and to address opportunities to improve energy efficiency within its various facilities. Improvements include: the conversion of Hillcrest subdivision to a higher voltage to reduce losses; designing the large transformers at Whistle Bend and at the Shipyard substation to ensure impedances are optimized to reduce internal losses; the current plans for building envelope improvements for the downtown office; insulation upgrades implemented in various plants; and air handling balancing and HVAC replacement in the service complex building. These improvements are outside the scope of the joint DSM plan.

Yukon Energy has completed some additional internal efficiency projects, pilot projects and public education initiatives, these activities along with the joint utility initiatives are outlined in section 5.3.1.5 of Yukon Energy's 2012-2013 General Rate Application and Yukon Energy's IR response YUB-YEC-1-46(d) Attachment 1. These activities are not part of the joint DSM plan. Costs associated with Yukon Energy's activities outside the joint DSM plan are not part of this application.

YCS-YECL-7-2

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain the assumptions that went into this prediction that solar PV would have no penetration until 2025.

Response:

Small-scale solar PV systems do not currently meet the CPR study's economic threshold; however, there is a general expectation that they are likely to become competitive with other electricity generation options sometime within the 20-year period covered by this study. For example, the U.S. Department of Energy's SunShot Initiative is aiming to achieve grid parity by 2020. Recently, a report by Ernst & Young suggested that retail grid parity might generally be achieved between 2012 and 2015. It is difficult to estimate at what point this might occur in the Yukon. On one hand, the installed cost per system will be more expensive than in other areas in Canada and the amount of electricity generated will be lower due to the lower insolation; on the other hand, the cost of electricity generated conventionally is also more expensive. Due to the possibility of PV grid parity during the study period, it was decided to include this technology within the Achievable Potential. During the achievable potential workshops, participants agreed that significant penetration of this technology is not likely to occur until 2025.

YCS-YECL-7-3

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain why considerable generation from solar PV could not happen now to supplement grid power and especially to displace fossil fuels in diesel communities, as opposed to waiting until 2025.

Response:

Yukon Electrical continues to examine renewable electricity generation sources including solar energy and wind energy. In the context of the DSM program, supply side generation was not examined.

YCS-YECL-7-4

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please explain what incentive programs or technologies were assumed to be in place for that considerable generation by 2025-2030.

Response:

As part of the Customer-side Renewable and Alternative Energy Technologies report, alternative energy incentive programs were not evaluated, only technologies considered. The specific technologies and the analysis of each technology is listed in Appendix G5, sections 5.4-5.9, pages 38-57 of the *Yukon Five Year Demand Side Management Plan* included in the Application.

YCS-YECL-7-5

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please describe how the programs in the DSM Plan will be accessible to customers outside of Whitehorse, and particularly in diesel-powered communities.

Response:

All residential and general service ratepayers will be eligible for programs listed in the joint DSM plan regardless of location in the Yukon.

YCS-YECL-7-6

Reference: Demand Side Management Plan

Conservation Potential Review Technical Summary Customer-side Renewable and Alternative Energy Technologies, Page 37 states: "Solar PV could provide considerable generation under the upper scenario, even though the penetration of this technology is expected to start later than for the others." Also noted in exhibits 18 and 19 is that no achievable potential from solar PV is predicted until 2025.

Request:

Please describe what programs exist in the DSM Plan to manage the load, as in to shift the demand from the peaks to the valleys. If there are no programs designed with the intention to shift demand from peaks to valleys, why not?

Response:

All programs included in the DSM Plan have coincidental peak savings, as outlined for each program shown in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management Plan* included in the Application. There are no specific programs to address peak shifting included in the DSM plan. Peak shifting programs tend to be costly and complex to administer as they require a high degree of customer participation and generally require enforceable regulation to ensure the technology is used during those peak times. Under the current rate structure and customer available data, there is no customer incentive to develop programing to address peak shifting. In developing their first DSM programs, the utilities focused on electricity usage savings which is more cost effective and results in coincidental peak savings.

Exhibit 4: Portfolio Results excluding Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - excluding gov. buildings	Lifetime MWh:	0	2,476	6,240	7,132	7,132	22,981	Incentive:	$4	$96	$213	$239	$222	$773	1.1	2.8	2.5	0.9
	Annual MWh:	0	333	1,140	2,062	2,985	N/A	Non-Incen.:	$77	$78	$81	$85	$111	$432				
	Coincident kW:	0	79	269	486	703	N/A	Total:	$81	$175	$294	$323	$333	$1,205				
New Construction Incentive - excluding gov. buildings	Lifetime MWh:	0	306	1,377	2,142	2,448	6,273	Incentive:	$0	$4	$19	$30	$34	$87	4.2	4.9	6.3	1.0
	Annual MWh:	0	15	84	191	314	N/A	Non-Incen.:	$4	$31	$5	$31	$12	$82				
	Coincident kW:	0	3	19	44	72	N/A	Total:	$4	$35	$24	$60	$46	$169				
High-Efficiency Refrigeration Incentive - excluding gov. buildings	Lifetime MWh:	0	0	6,301	0	6,301	12,602	Incentive:	$0	$0	$122	$0	$122	$243	3.2	4.5	4.2	1.0
	Annual MWh:	0	0	630	630	1,260	N/A	Non-Incen.:	$10	$91	$17	$54	$42	$214				
	Coincident kW:	0	0	72	72	143	N/A	Total:	$10	$91	$138	$54	$163	$458				
Energy Star Computer - excluding gov. buildings	Lifetime MWh:	32	205	335	0	0	573	Incentive:	$2	$10	$17	$0	$0	$29	1.8	1.2	*	0.6
	Annual MWh:	8	59	143	143	135	N/A	Non-Incen.:	$26	$12	$15	$2	$5	$60				
	Coincident kW:	1	11	26	26	24	N/A	Total:	$28	$22	$32	$2	$5	$89				
Engagement, Education and Communication - excluding gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$167	$251	$224	$175	$217	$1,034				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$167	$251	$224	$175	$217	$1,034				
Total General Service Program excl. gov. buildings	Lifetime MWh:	32	2,988	14,253	9,274	15,881	42,428	Incentive:	$5	$111	$371	$268	$377	$1,132	1.3	2.1	3.2	0.8
	Annual MWh:	8	408	1,997	3,027	4,693	N/A	Non-Incen.:	$284	$463	$341	$346	$387	$1,822				
	Coincident kW:	1	93	385	627	942	N/A	Total:	$290	$574	$712	$615	$764	$2,954				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,747	10,294	21,319	17,243	23,504	75,108	Incentive:	$56	$219	$474	$380	$477	$1,606	1.3	2.1	2.9	0.8
	Annual MWh:	221	1,167	3,287	4,887	7,098	N/A	Non-Incen.:	$706	$824	$670	$703	$815	$3,718				
	Coincident kW:	77	363	845	1,290	1,800	N/A	Total:	$762	$1,043	$1,145	$1,083	$1,292	$5,325				

Exhibit 5: Portfolio Results Including Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - including gov. buildings	Lifetime MWh:	0	4,314	10,711	12,241	12,241	39,506	Incentive:	$6	$135	$294	$327	$299	$1,062	1.2	3.8	2.4	0.9
	Annual MWh:	0	507	1,731	3,128	4,526	N/A	Non-Incen.:	$81	$77	$66	$72	$127	$425				
	Coincident kW:	0	127	432	781	1,129	N/A	Total:	$88	$213	$360	$400	$427	$1,487				
New Construction Incentive - including gov. buildings	Lifetime MWh:	0	471	2,118	3,295	3,766	9,651	Incentive:	$0	$6	$25	$39	$45	$115	4.7	6.1	6.7	1.0
	Annual MWh:	0	24	129	294	483	N/A	Non-Incen.:	$28	$9	$6	$33	$16	$93				
	Coincident kW:	0	5	30	67	110	N/A	Total:	$28	$15	$32	$72	$61	$208				
High-Efficiency Refrigeration Incentive - including gov. buildings	Lifetime MWh:	0	0	7,580	0	7,580	15,161	Incentive:	$0	$0	$132	$0	$132	$263	3.2	4.3	4.6	1.0
	Annual MWh:	0	0	694	694	1,388	N/A	Non-Incen.:	$36	$100	$19	$86	$49	$290				
	Coincident kW:	0	0	80	80	161	N/A	Total:	$36	$100	$151	$86	$180	$553				
Energy Star Computer - including gov. buildings	Lifetime MWh:	107	681	1,111	0	0	1,899	Incentive:	$6	$35	$57	$0	$0	$98	2.0	1.3	*	0.6
	Annual MWh:	27	197	475	475	448	N/A	Non-Incen.:	$36	$52	$74	$6	$17	$185				
	Coincident kW:	5	35	85	85	80	N/A	Total:	$41	$88	$131	$6	$17	$284				
Engagement, Education and Communication - including gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$202	$290	$255	$200	$252	$1,199				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$202	$290	$255	$200	$252	$1,199				
Total General Service Program incl. gov. buildings	Lifetime MWh:	107	5,466	21,520	15,536	23,587	66,217	Incentive:	$12	$176	$508	$367	$476	$1,538	1.3	2.5	3.2	0.8
	Annual MWh:	27	728	3,029	4,591	6,845	N/A	Non-Incen.:	$383	$529	$420	$398	$461	$2,192				
	Coincident kW:	5	167	627	1,013	1,480	N/A	Total:	$395	$705	$928	$765	$937	$3,730				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,822	12,772	28,586	23,505	31,210	98,896	Incentive:	$63	$284	$612	$478	$576	$2,012	1.4	2.3	2.9	0.8
	Annual MWh:	240	1,487	4,318	6,451	9,250	N/A	Non-Incen.:	$762	$957	$782	$787	$904	$4,191				
	Coincident kW:	81	438	1,087	1,677	2,338	N/A	Total:	$824	$1,240	$1,393	$1,266	$1,480	$6,203				

YEC-YECL-1

Reference: Overall Revenue Requirement – Requested Rate Increases and Revenue Requirement

Request:

(a) Please confirm that the requested year-over-year rate increase is 6.1% for 2013, 3.2% for 2014 and 2.0% for 2015.

(b) If a) is not confirmed, please provide details of the requested year-over-year rate increase calculations for 2013, 2014 and 2015.

(c) Please provide Schedule 8.1 for 2008-2015 without 2013-2015 GRA, i.e. forecast Return on Equity (ROE), equity ratios and Rate Base forecast for 2013-2015 years without GRA application.

Response:

(a) Confirmed.

(b) n/a

(c) Please refer to YEC-YECL-1(c) Attachment 1.

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2008 Actual**						
2	Long-Term Debt	S.8.2 L.19	24,575	56.81%	26,100	6.97%	1,819
3	Common Stock		17,994	41.59%	19,110	7.03%	1,344
4	No Cost Capital	S.8.4 L.8	693	1.60%	735	0.00%	-
5	Total	S.8.5 L.21 S.1.1 L.15	43,262	100.0%	45,946	6.88%	3,163
6	**2009 Actual**						
7	Long-Term Debt	S.8.2 L.42	27,650	57.34%	28,166	6.73%	1,895
8	Common Stock		19,866	41.20%	20,236	11.35%	2,296
9	No Cost Capital	S.8.4 L.8	702	1.45%	715	0.00%	-
10	Total	S.8.5 L.21 S.1.1 L.15	48,217	100.0%	49,116	8.53%	4,191
11	**2010 Actual**						
12	Long-Term Debt	S.8.2 L.63	29,950	57.27%	28,649	6.58%	1,884
13	Common Stock		21,682	41.46%	20,740	10.54%	2,187
14	No Cost Capital	S.8.4 L.8	666	1.27%	637	0.00%	-
15	Total	S.8.5 L.21 S.1.1 L.15	52,298	100.0%	50,026	8.14%	4,071
16	**2011 Actual**						
17	Long-Term Debt	S.8.2 L.85	32,450	57.36%	30,062	6.42%	1,931
18	Common Stock		23,472	41.49%	21,745	10.74%	2,335
19	No Cost Capital	S.8.4 L.8	649	1.15%	601	0.00%	-
20	Total	S.8.5 L.21 S.1.1 L.15	56,571	100.0%	52,408	8.14%	4,266
21	**2012 Actual**						
22	Long-Term Debt	S.8.2 L.107	36,950	58.35%	35,032	6.16%	2,158
23	Common Stock		25,740	40.65%	24,404	10.18%	2,484
24	No Cost Capital	S.8.4 L.8	631	1.00%	598	0.00%	-
25	Total	S.8.5 L.21 S.1.1 L.15	63,321	100.0%	60,034	7.73%	4,642

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**						
27	Long-Term Debt	S.8.3 L.23	43,014	59.49%	43,352	5.88%	2,549
28	Common Stock		28,676	39.66%	28,902	3.08%	890
29	No Cost Capital	S.8.4 L.8	613	0.85%	618	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,303	100.0%	72,872	4.72%	3,439
31	**2014 Test Period**						
32	Long-Term Debt	S.8.3 L.48	51,372	59.59%	52,408	5.71%	2,992
33	Common Stock		34,248	39.72%	34,939	-2.88%	(1,006)
34	No Cost Capital	S.8.4 L.8	595	0.69%	607	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,215	100.0%	87,954	2.26%	1,986
36	**2015 Test Period**						
37	Long-Term Debt	S.8.3 L.73	58,446	59.65%	59,903	5.69%	3,406
38	Common Stock		38,964	39.76%	39,935	-5.32%	(2,124)
39	No Cost Capital	S.8.4 L.8	577	0.59%	591	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	97,987	100.0%	100,430	1.28%	1,282
41	**2008 GRA Approved**						
42	Long-Term Debt	S.8.2 L.126	26,621	59.11%	27,244	6.87%	1,870
43	Common Stock		17,747	39.41%	18,162	9.08%	1,649
44	No Cost Capital	S.8.4 L.8	669	1.49%	685	0.00%	-
45	Total	S.8.5 L.21 S.1.1 L.15	45,037	100%	46,091	7.63%	3,519
46	**2009 GRA Approved**						
47	Long-Term Debt	S.8.2 L.148	29,730	59.17%	29,276	6.60%	1,934
48	Common Stock		19,820	39.45%	19,517	8.92%	1,741
49	No Cost Capital	S.8.4 L.8	695	1.38%	684	0.00%	-
50	Total	S.8.5 L.21 S.1.1 L.15	50,245	100%	49,478	7.43%	3,675

YEC-YECL-2

Reference: Section 2 – Sales and Revenue – Sales Forecast

Request:

(a) Please provide a table with comparison of YECL's forecast (YECL internal and GRA) and actual sales by rate class and by rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) for 2008, 2009, 2010, 2011 and 2012.

(b) Please provide Table 2 on page 2-2 by comparing 2008 - 2009 GRA forecasts to the actual sales, instead of actual normalized sales.

(c) Is the sales forecast method proposed in this application the same as used in YECL's 2008/09 General Rate Application? If not, please enumerate any differences and provide an explanation for why the forecasting method was changed.

Response:

(a) Please refer to YEC-YECL-2(a) Attachment 1 for tables comparing Yukon Electrical's 2008 and 2009 forecast and sales by rate class by rate zone. As lighting rates are the same for all rate zones, the forecast is not available on a rate zone basis. Yukon Electrical did not prepare sales forecasts for 2010, 2011 or 2012 with the same level of detail, rigor or comprehensiveness as it does for GRA test years. Accordingly, Yukon Electrical is not prepared to submit a sales variance comparison for those years as it does not view such a comparison as being appropriate.

(b) Please refer to YEC-YECL-2(b) Schedule 1.

(c) Please refer to YEC-YECL-2(c) Attachment 1.

The Yukon Electrical Company Limited
Sales (MWh) Variance by Rate Zone

Hydro Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	116,772	119,640	2,868	2.5%
Commercial	133,594	132,077	-1,517	-1.1%
Total	250,366	251,717	1,351	0.5%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	119,951	121,938	1,986	1.7%
Commercial	134,812	132,624	-2,188	-1.6%
Total	254,763	254,561	-202	-0.1%

Large Diesel Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	6,318	6,493	174	2.8%
Commercial	7,246	6,597	-650	-9.0%
Total	13,565	13,090	-475	-3.5%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	6,340	6,445	105	1.7%
Commercial	7,377	6,562	-815	-11.0%
Total	13,717	13,006	-710	-5.2%

Small Diesel Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	2,378	1,242	-1,137	-47.8%
Commercial	3,065	2,266	-800	-26.1%
Total	5,444	3,507	-1,937	-35.6%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	1,329	1,212	-117	-8.8%
Commercial	2,382	2,119	-263	-11.1%
Total	3,712	3,331	-381	-10.3%

Old Crow Rate Zone

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	972	928	-44	-4.5%
Commercial	795	765	-31	-3.9%
Total	1,767	1,692	-75	-4.2%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	995	975	-20	-2.0%
Commercial	794	772	-22	-2.8%
Total	1,788	1,747	-41	-2.3%

Total

2008	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	126,441	128,302	1,861	1.5%
Commercial	144,701	141,704	-2,997	-2.1%
Lighting	4,082	4,176	94	2.3%
Total	275,224	274,182	-1,042	-0.4%

2009	08/09 GRA Forecast MWh	Actual MWh	Var MWh	Var%
Residential	128,615	130,569	1,954	1.5%
Commercial	145,365	142,077	-3,289	-2.3%
Lighting	4,153	4,069	-84	-2.0%
Total	278,133	276,714	-1,419	-0.5%

Table 2
Yukon Electrical Sales Variance
2008-2009 GRA Forecast

2008				
	Forecast (MW.h)	Actual[3] (MW.h)	Variance (MW.h)	(%)
Filed[1]				
Total Sales	269,913	274,182	4,269	1.6
Approved[2]				
Total Sales	275,224	274,182	-1,043	-0.4
2009				
	Forecast (MW.h)	**Actual[3] (MW.h)**	**Variance (MW.h)**	**(%)**
Filed[1]				
Total Sales	272,054	276,714	4,660	1.7
Approved[2]				
Total Sales	278,133	276,714	-1,419	-0.5

1) Schedule 2.1, 2008-2009 GRA

2) Schedule 2.1, Compliance Filing, Board Order 2009-5

3) Line 29, Schedule 2.1, 2013-2015 GRA

A Comparison of Yukon Electrical's GRA Sales Forecast Methodologies

Revenue Class/Variable	2008-2008 GRA	2013-2015 GRA	Rationale
Residential:			
Customer	· Based on Yukon Electrical's work in the community and consultation with local officials/developers and the Yukon Gov't and trend analysis.	· The same approach as in the 2008-2009 GRA.	
UPC	· For all communities with the exception of Whitehorse and Watson Lake, the most recent 3-year average UPC was used. · For Whitehorse and Watson Lake, the most recent 3-year average weather-normalized UPC.	· For all communities with the exception of Keno City, Stewart Crossing, Swift River and Whitehorse, the most recent 3-year average weather-normalized UPC. · For Keno City, Stewart Crossing and Swift River, the most recent 3-year average UPC because there are very few customers in these communities and a poor correlation between their average UPC and HDD. · For Whitehorse, 2013 was forecast by escalating the 2012 normalized UPC by the 3-year average growth rate of normalized UPC, and was kept constant for 2014 and 2015.	· YECL believes using a weather-normalized approach, whenever possible, which eliminates the impact of an abnormally cold/warm year, is a preferable method of forecasting energy consumption for a jurisdiction.
Commercial:			
Customer	· Based on YECL's work in the community and consultation with local officials/developers and the Yukon Gov't. and trend analysis.	· The same approach as in the 2008-2009 GRA.	
UPC	· For all communities with the exception of Whitehorse and Watson Lake, the most recent 3-year average UPC was used. · For Whitehorse and Watson Lake, the most recent 3-year average weather-normalized UPC.	· The same approach as in the 2008-2009 GRA for all communities except for Watson Lake where the base year UPC was forecast based on the most recent 3-year average UPC.	· Watson Lake R^2 is low.

Lighting:	· Based on YECL's work in the community and consultation with local officials/developers number of lights (streetlights and private lights) · Energy for streetlights and private lights is calculated by multiplying the number of lights with average use per light.	· The same approach as in the 2008-2009 GRA · The same approach as in the 2008-2009 GRA	No new LED conversions are incorporated into the forecast and average use per light is constant. Therefore, the main driver of the energy forecast is the additional number of lights.

YEC-YECL-3

Reference: Section 2 – Sales and Revenue – Residential Sales Forecast

Request:

(a) Please provide details of residential customer forecast for 2013, 2014 and 2015. Please include list of "all known residential property developments" (page 2-5, line 1) included in forecast as well as the estimated additional number of customers for each development area.

(b) Does the residential customer forecast also consider population growth forecasts? If so please provide the source of the population growth forecasts. If not, please explain why population growth forecasts are not considered.

(c) Please provide the impact for each forecast year of using the three-year average usage per customer (UPC) for Whitehorse. Please provide calculations in an excel file.

(d) Given the poor R2 correlation factor for residential customer UPC using single variable regression did YECL consider multiple variable regression analysis for UPC? If not, why not.

(e) Please provide any assessments as to sensitivity of such regressions as between different months or seasons.

(f) Please confirm that YECL used a twenty year rolling average of Heating Degree Days (HDD) [page 2-5, line 22].

(g) If f) above is confirmed please explain why attachments 1 through 21 show data only for 1998-2012. Please provide calculations in an excel file.

(h) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in excel file.

Response:

(a) Details of residential customer forecast with all known residential property developments are provided in YEC-YECL-3(a) Attachment 1.

(b) No, Yukon Electrical did not consider the population growth because we are not aware of the availability of a population forecast for the test period by community from a reliable independent source, which can be used in its customer count forecast.

(c) Please refer to YEC-YECL-3(c) Attachment 1.

(d) Yukon Electrical did not consider the use of a multi-variant regression because adding more independent variables to the regression equation, the sole purpose of which is to identify and quantify the impact of weather on average consumption, would obscure the impact of the weather variable.

In addition, as Attachment 21 of the Application indicates, the R^2 for the regression between UPC and HDD for the various communities ranges between 50% to 84%, with a t-stat greater than 2. This indicates that the HDD variable is significant at a 5% confidence interval. In other words the temperature (HDD) is responsible for at least 50% to 84% of variations in average electricity consumption in those communities. Given the small size of these communities and the lack of appropriate data, Yukon Electrical believes it is reasonable to use the approach it has used in forecasting the future energy consumption for the test period.

(e) If Yukon Electrical's understanding of this question is correct, the question is asking to perform 320 regressions, (20 communities * (12 months + 4 seasons)) for the assessment of the monthly and seasonal sensitivities. Yukon Electrical does not see the relevance of this question with respect to its proposed sales forecast and, given the significant amount of work it entails, is not prepared to complete the analysis to answer the question.

(f) Confirmed.

(g) Yukon Electrical used 15 years of data for the UPC and HDD regression because that is the highest number of years for which Yukon Electrical has data for all communities. Please refer to YUB-YECL-57 Attachments for details.

(h) Please refer to YEC-YECL-3(h) Attachment 1 for billed sales by month for each test year by rate zone. The forecast is created on a monthly billed basis and is then converted to an earned forecast, which aligns with Schedule 2.1 in this Application.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Residential Customer Forecast by Community

Communities	2013	2014	2015
Carmacks	215	219	223
Carcross	253	257	261
Haines Junction	390	397	404
Teslin	280	285	290
Upper Liard	54	55	56
Destruction Bay	96	98	100
Whitehorse	10,792	10,975	11,161
Beaver Creek	72	73	74
Watson Lake	593	603	614
Old Crow	144	146	149
Keno City	42	43	44
Stewart Crossing	13	13	13
Lower Post B.C.	56	57	58
Ross River	180	183	186
Pelly Crossing	155	158	161
Swift River	2	2	2
Tagish	347	353	359
Marsh Lake	437	444	452
Deep Creek	41	42	43
Minto Landing	-	-	-
TOTAL Residential	14,159	14,401	14,647

Known Residential Property Developments

	Customer Adds		
Projects	2013	2014	2015
Mah's Point	53	-	-
Rivers Edge	15	-	-
Yukon Housing Development 4th Ave	16	-	-
Whistle Bend stage 1,2,3	25	20	20
Crocus Glen	9	9	7
Evergreen	27	20	-
Brookside Place	14	8	8
Grizzly Valley	5	3	3
Ingram	13	5	-
TTC	4	5	5
Lower Post	10	6	-
Raven Ridge	2	5	3
Other Customer Adds	109	161	200
Total Adds	302	242	246

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	Annual UPC (kWh)
Jan-98	1334.11	1165.70	1,295		
Feb-98	1071.75	719.10	1,134		
Mar-98	1027.75	756.60	1,043		
Apr-98	902.89	458.60	921		
May-98	787.72	270.60	815		
Jun-98	696.64	119.50	719		
Jul-98	627.52	111.60	628		
Aug-98	604.15	189.20	592		
Sep-98	706.17	327.80	699		
Oct-98	780.59	557.70	772		
Nov-98	922.54	792.30	936		
Dec-98	970.68	1051.80	927		
Jan-99	1383.18	1183.10	1,334		
Feb-99	1164.46	976.40	1,088		
Mar-99	1040.97	734.00	1,069		
Apr-99	944.37	508.80	936		
May-99	811.83	391.90	774		
Jun-99	754.75	153.90	758		
Jul-99	646.43	108.60	649		
Aug-99	610.64	145.70	621		
Sep-99	697.48	311.20	700		
Oct-99	763.70	499.80	786		
Nov-99	881.73	792.50	895		
Dec-99	994.21	844.00	1,062		
Jan-00	1264.66	1082.90	1,270		
Feb-00	1036.07	735.20	1,090		
Mar-00	918.53	659.20	986		
Apr-00	854.15	515.60	842		
May-00	846.79	382.00	815		
Jun-00	731.77	172.50	725		
Jul-00	656.21	142.10	641		
Aug-00	620.05	219.90	591		
Sep-00	733.99	354.20	713		
Oct-00	787.21	539.20	788		
Nov-00	884.41	691.20	952		
Dec-00	940.26	977.80	936		
Jan-01	1185.33	722.70	1,384		
Feb-01	938.26	864.10	922		
Mar-01	987.72	765.30	998		
Apr-01	867.85	506.80	860		
May-01	816.38	390.40	780		
Jun-01	763.40	167.30	760		
Jul-01	657.29	139.60	643		
Aug-01	598.61	139.60	613		
Sep-01	660.89	309.00	664		
Oct-01	754.64	573.40	737		
Nov-01	904.51	818.00	904		
Dec-01	1056.40	1094.60	989		
Jan-02	1223.01	935.60	1,307		
Feb-02	1013.30	824.60	1,019		
Mar-02	997.99	921.10	925		
Apr-02	990.09	653.30	904		
May-02	798.77	361.60	777		
Jun-02	707.08	175.60	699		
Jul-02	642.71	130.90	633		
Aug-02	648.08	182.80	639		
Sep-02	680.33	314.40	681		
Oct-02	758.56	444.30	811		
Nov-02	873.29	582.60	999		
Dec-02	898.43	845.20	966		

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	Annual UPC (kWh)
Jan-03	1202.44	989.10	1,258		
Feb-03	995.15	756.60	1,037		
Mar-03	985.34	834.50	959		
Apr-03	892.59	514.30	881		
May-03	790.52	363.70	768		
Jun-03	749.45	192.80	732		
Jul-03	657.75	84.40	673		
Aug-03	617.42	180.60	609		
Sep-03	709.08	359.20	685		
Oct-03	726.71	466.70	767		
Nov-03	910.68	874.60	880		
Dec-03	1072.98	911.60	1,104		
Jan-04	1245.81	1257.90	1,157		
Feb-04	1092.27	697.20	1,166		
Mar-04	923.71	753.50	941		
Apr-04	948.79	466.60	963		
May-04	751.60	272.50	778		
Jun-04	711.26	83.70	753		
Jul-04	667.46	74.20	688		
Aug-04	607.29	101.70	642		
Sep-04	669.67	367.50	642		
Oct-04	761.52	540.50	762		
Nov-04	897.87	719.80	950		
Dec-04	1015.36	899.50	1,053		
Jan-05	1277.77	1165.80	1,238		
Feb-05	1107.70	795.20	1,129		
Mar-05	922.86	613.70	1,015		
Apr-05	906.16	453.30	928		
May-05	734.86	256.60	770		
Jun-05	705.13	154.40	709		
Jul-05	660.11	132.60	650		
Aug-05	621.38	150.80	629		
Sep-05	741.98	299.30	751		
Oct-05	733.74	534.60	737		
Nov-05	921.61	762.60	951		
Dec-05	967.23	794.40	1,062		
Jan-06	1196.53	1096.20	1,195		
Feb-06	1043.82	821.30	1,051		
Mar-06	1072.57	906.30	1,007		
Apr-06	933.65	519.10	920		
May-06	801.77	346.90	788		
Jun-06	726.49	173.10	720		
Jul-06	704.17	118.40	701		
Aug-06	635.06	201.60	616		
Sep-06	736.28	295.70	747		
Oct-06	795.22	520.50	806		
Nov-06	938.75	1162.20	753		
Dec-06	1130.58	824.30	1,209		
Jan-07	1245.66	912.00	1,343		
Feb-07	1050.91	998.80	962		
Mar-07	1139.27	954.20	1,048		
Apr-07	985.39	511.90	975		
May-07	735.33	322.10	735		
Jun-07	719.79	140.50	731		
Jul-07	702.49	102.30	708		
Aug-07	597.33	154.20	604		
Sep-07	688.79	308.40	692		
Oct-07	754.77	543.70	753		
Nov-07	922.64	724.60	972		
Dec-07	995.15	1069.50	942		

Yukon Electrical Company Limited
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Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)		Annual UPC (kWh)
Jan-08	1298.44	1113.80	1,287			
Feb-08	1185.79	954.60	1,121			
Mar-08	1011.53	734.70	1,039			
Apr-08	942.12	517.30	929			
May-08	788.52	307.90	796			
Jun-08	696.47	225.60	662			
Jul-08	680.93	173.40	648			
Aug-08	700.97	187.70	689			
Sep-08	700.67	318.70	699			
Oct-08	732.64	563.00	721			
Nov-08	984.81	782.50	1,003			
Dec-08	1011.40	1186.20	895			
Jan-09	1528.55	1137.90	1,504			
Feb-09	1122.38	955.40	1,057			
Mar-09	1093.54	868.50	1,049			
Apr-09	945.55	515.20	934			
May-09	773.10	331.20	768			
Jun-09	704.15	144.10	713			
Jul-09	702.59	62.50	730			
Aug-09	627.45	158.30	632			
Sep-09	719.71	306.10	725			
Oct-09	771.84	541.80	771			
Nov-09	953.63	781.50	973			
Dec-09	1013.21	943.40	1,027	10882.60		
Jan-10	1345.94	991.10	1,401			
Feb-10	1012.55	679.20	1,096			
Mar-10	940.25	656.00	1,010			
Apr-10	944.91	461.20	962			
May-10	795.15	292.00	811			
Jun-10	719.19	171.90	713			
Jul-10	685.61	117.30	683			
Aug-10	627.66	146.20	638			
Sep-10	720.70	332.40	711			
Oct-10	821.83	520.40	833			
Nov-10	904.24	717.60	958			
Dec-10	1057.11	1162.50	953	10770.18		10,575
Jan-11	1436.52	1010.20	1,481			
Feb-11	1129.49	905.60	1,091			
Mar-11	1256.14	901.70	1,193			
Apr-11	955.17	511.20	945			
May-11	892.99	296.20	907			
Jun-11	743.84	161.00	744			
Jul-11	677.48	127.80	670			
Aug-11	647.93	217.90	620			
Sep-11	737.64	328.50	731			
Nov-11	831.75	513.30	847			
Nov-11	943.59	936.25	879			
Dec-11	1136.92	775.10	1,242	11349.30		11,389
Jan-12	1356.98	1118.10	1,343			
Feb-12	1170.51	707.50	1,239			
Mar-12	1098.22	756.20	1,114			
Apr-12	930.47	450.60	953			
May-12	835.03	350.80	820			
Jun-12	770.21	200.00	749			
Jul-12	708.91	140.10	694			
Aug-12	677.42	157.90	682			
Sep-12	695.14	287.15	710			
Oct-12	802.64	631.40	754			
Nov-12	1011.59	969.60	929			
Dec-12	1262.76	1196.80	1,141	11128.22	0.7%	11,320

	Using 3-yr Avg UPC (kWh)	Δ (kWh)	Whitehorse Customer Forecast (annual Avg)	Energy Impact Whitehorse (MWh)
2013-F	11,095	(116)	10,792	(1,257)
2014-F	11,095	(116)	10,975	(1,279)
2015-F	11,095	(116)	11,161	(1,300)

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Residential Regression Results (Yukon Electrical 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

The Yukon Electrical Company Limited
Residential Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	14,196	13,316	11,120	10,219	8,680	7,654	7,456	7,799	7,809	8,251	11,001	11,466	118,968	119,640
2009	17,006	12,669	12,236	10,597	8,732	7,877	7,939	7,105	8,121	8,857	10,838	11,666	123,642	121,938
2010	15,357	11,603	10,761	10,802	9,097	8,170	7,947	7,262	8,338	9,550	10,574	12,450	121,911	122,732
2011	16,897	13,265	14,626	11,210	10,426	8,653	8,025	7,693	8,787	9,858	11,406	13,655	134,500	132,820
2012	16,437	14,137	13,323	11,090	10,060	9,326	8,544	8,309	8,557	9,883	12,686	15,764	138,117	141,284
2013 F	16,936	15,348	13,909	11,867	10,255	9,294	8,688	8,534	9,001	9,612	11,870	14,500	139,815	143,018
2014 F	17,225	15,609	14,147	12,069	10,430	9,453	8,837	8,680	9,154	9,776	12,073	14,748	142,201	145,460
2015 F	17,522	15,877	14,389	12,273	10,607	9,617	8,989	8,828	9,311	9,944	12,276	14,999	144,632	147,947

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	793	718	576	549	473	402	416	420	419	474	578	638	6,456	6,493
2009	826	660	619	568	479	409	424	390	444	476	557	683	6,535	6,445
2010	788	614	558	548	464	418	401	379	432	518	533	652	6,305	6,352
2011	820	624	692	574	490	434	386	405	462	476	559	653	6,577	6,496
2012	808	658	618	549	501	434	413	404	384	486	544	690	6,488	6,617
2013 F	792	604	589	536	474	419	394	388	421	474	502	627	6,222	6,345
2014 F	806	614	599	545	482	426	401	395	428	482	511	637	6,328	6,454
2015 F	820	625	609	555	491	434	408	402	436	491	520	649	6,439	6,567

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	138	125	110	110	95	92	81	88	79	82	109	126	1,235	1,242
2009	141	127	118	115	90	78	87	79	87	90	107	111	1,229	1,212
2010	153	116	103	108	98	80	84	72	83	93	103	111	1,206	1,210
2011	148	130	122	114	91	83	83	83	88	97	117	147	1,303	1,290
2012	162	133	131	99	87	99	83	89	86	99	121	153	1,341	1,373
2013 F	161	132	122	110	93	88	84	82	87	98	112	137	1,306	1,337
2014 F	163	135	125	112	95	89	85	84	89	99	114	139	1,328	1,360
2015 F	166	137	127	114	97	91	86	85	90	101	116	141	1,351	1,383

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	91	104	75	77	76	78	57	76	64	57	89	78	922	928
2009	120	88	90	91	84	71	75	57	60	84	88	80	989	975
2010	112	94	87	104	67	62	71	58	67	84	81	89	975	979
2011	147	106	94	121	96	64	76	64	73	72	80	114	1,108	1,089
2012	110	104	119	94	80	81	61	83	49	72	92	112	1,058	1,076
2013 F	128	107	104	110	84	71	71	70	64	77	84	105	1,075	1,092
2014 F	130	108	105	112	85	72	72	71	65	78	85	107	1,090	1,107
2015 F	132	110	107	114	86	73	73	72	67	79	87	109	1,108	1,126

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	15,218	14,264	11,882	10,954	9,324	8,226	8,010	8,384	8,371	8,865	11,777	12,307	127,581	128,302
2009	18,093	13,543	13,062	11,371	9,384	8,435	8,525	7,631	8,712	9,507	11,590	12,542	132,394	130,569
2010	16,409	12,427	11,511	11,562	9,726	8,730	8,503	7,770	8,920	10,246	11,292	13,303	130,397	131,273
2011	18,012	14,125	15,534	12,018	11,103	9,234	8,570	8,246	9,411	10,503	12,162	14,569	143,488	141,696
2012	17,518	15,032	14,189	11,833	10,729	9,940	9,100	8,885	9,076	10,541	13,443	16,719	147,005	150,350
2013 F	18,017	16,191	14,724	12,623	10,906	9,872	9,237	9,075	9,574	10,261	12,568	15,369	148,417	151,793
2014 F	18,325	16,467	14,975	12,838	11,092	10,040	9,395	9,229	9,737	10,436	12,783	15,631	150,947	154,381
2015 F	18,640	16,748	15,232	13,055	11,281	10,214	9,557	9,387	9,905	10,616	12,999	15,898	153,530	157,023

YEC-YECL-4

Reference: Section 2 – Sales and Revenue – Commercial Sales Forecast

Request:

(a) Please provide details of commercial customer forecast for 2013, 2014 and 2015. Please include a list of the twelve new large commercial customers with the forecast load for each customer for all test years. Provide for each year included in the GRA (2010-2015) the number of new commercial customers in Whitehorse and the average UPC each year for these new customers.

(b) Please confirm that for Watson Lake the most recent three-year average actual UPC was used.

(c) Please discuss why weather normalized UPC is not used for commercial sales forecast.

(d) Please provide the impact for each forecast year of using the three-year average UPC for Whitehorse. Please provide calculations in an excel file.

(e) Please provide the 2012 actual loads for the "several secondary commercial customers" who converted to primary service as referenced (page 2-12, lines 13-15).

(f) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in an excel file.

Response:

(a) Please refer to the response to information request CW-YECL-3.

(b) Confirmed.

(c) As stated on Page 2-5 and 2-6 of the Application, actual weather-normalized UPC is used for determining the forecast of the commercial sales in Whitehorse. However, weather normalization was not used for the remaining communities

because of a poor correlation between the average UPC and HDD for those individual communities.

(d) As indicated in YEC-YECL-4(d) Attachment 1, the 3 year average actual commercial UPC would result in a lower energy forecast than the proposed values in Yukon Electrical's 2013-15 GRA.

(e) As detailed in the table below, the 2012 actual load for the 12 customers who converted from secondary to primary service was 2,489 MWh.

Customer ID	Load (MWh)
Customer 1	163
Customer 2	17
Customer 3	42
Customer 4	86
Customer 5	19
Customer 6	2
Customer 7	292
Customer 8	-
Customer 9	-
Customer 10	6
Customer 11	1,862
Customer 12	-
Total	2,489

(f) Please refer to YEC-YECL-4(f) Attachment 1 for billed sales by month for each test year by rate zone. The forecast is created on a monthly billed basis and then converted to an earned forecast which aligns with Schedule 2.1 of the Application.

The Yukon Electrical Company Limited
Commercial UPC and Energy - 3 Year Average Actual vs Normalized

	Annual 3 Year Average Actual UPC (kWh)	Annual Normalized UPC (kWh)	Annual Average Customer (kWh)
2013	66,969	67,270	2,031
2014	66,969	67,923	2,055
2015	66,969	68,355	2,087

	Annual 3 Year Average Actual UPC_Energy (MWh)	Annual Normalized UPC_Energy (MWh)	Difference (MWh)
2013	135,993	136,605	(612)
2014	137,619	139,580	(1,961)
2015	139,732	142,625	(2,893)

The Yukon Electrical Company Limited
Commercial Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	13,392	12,880	11,297	11,722	9,798	9,904	9,341	10,749	9,755	9,835	11,687	11,359	131,719	132,077
2009	14,786	11,791	12,440	11,488	10,082	9,653	10,555	10,021	9,513	9,958	11,427	11,340	133,054	132,623
2010	14,052	11,787	11,604	11,971	10,395	10,468	10,089	10,026	9,787	10,573	12,084	12,272	135,110	136,223
2011	15,259	12,317	13,877	11,825	11,360	10,549	10,410	10,269	10,712	11,075	12,068	13,033	142,755	141,006
2012	15,677	13,178	13,063	12,764	11,533	10,991	10,836	10,520	10,157	11,438	12,490	13,993	146,641	149,182
2013 F	16,004	13,804	13,413	13,209	11,728	11,111	10,901	10,807	10,590	11,566	12,298	13,683	149,115	151,698
2014 F	16,341	14,121	13,728	13,498	12,008	11,384	11,173	10,924	10,712	11,816	12,580	13,991	152,277	154,915
2015 F	16,688	14,435	14,037	13,804	12,293	11,660	11,446	11,189	10,969	11,969	12,789	14,243	155,521	158,215

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	621	641	583	544	526	497	535	555	473	466	568	570	6,579	6,597
2009	670	591	566	540	496	481	531	503	480	542	685	499	6,583	6,562
2010	681	640	571	579	473	474	519	489	414	596	574	609	6,619	6,681
2011	703	575	646	538	512	494	477	406	494	527	599	641	6,611	6,537
2012	782	633	666	587	565	558	494	533	607	374	661	707	7,165	7,287
2013 F	740	633	649	582	497	470	494	475	527	514	639	694	6,913	7,030
2014 F	776	670	687	620	535	509	498	479	533	520	647	704	7,179	7,300
2015 F	787	680	697	629	543	517	505	486	540	528	657	714	7,284	7,408

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	214	242	142	183	205	174	192	225	173	144	185	181	2,260	2,266
2009	222	201	176	184	144	168	205	180	181	177	123	165	2,126	2,119
2010	216	173	162	168	161	180	200	195	172	164	167	166	2,123	2,135
2011	224	175	193	184	212	176	181	197	192	163	168	184	2,250	2,222
2012	231	179	184	164	152	195	170	202	175	161	172	174	2,157	2,191
2013 F	215	168	172	153	145	149	149	159	151	140	155	170	1,926	1,956
2014 F	218	171	175	155	148	152	152	161	153	142	157	173	1,956	1,987
2015 F	222	174	178	158	150	154	154	164	156	145	160	176	1,989	2,020

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	67	83	67	61	64	65	46	63	51	46	78	71	763	765
2009	86	64	77	74	69	53	66	46	45	67	59	69	775	772
2010	82	65	65	80	54	54	48	46	47	60	66	66	734	737
2011	87	80	73	73	73	62	62	55	61	59	69	83	838	826
2012	82	74	96	81	65	74	52	71	50	65	65	111	887	903
2013 F	90	78	84	84	68	68	57	59	55	63	69	90	866	881
2014 F	91	79	85	86	69	69	58	60	56	64	70	91	878	893
2015 F	93	80	86	87	70	70	59	61	56	65	71	92	891	906

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	14,295	13,845	12,090	12,510	10,593	10,640	10,114	11,592	10,451	10,492	12,517	12,181	141,320	141,704
2009	15,764	12,647	13,260	12,285	10,791	10,355	11,358	10,749	10,218	10,744	12,294	12,073	142,538	142,076
2010	15,031	12,664	12,402	12,799	11,083	11,176	10,856	10,756	10,421	11,393	12,891	13,114	144,586	145,776
2011	16,274	13,146	14,790	12,621	12,156	11,282	11,130	10,928	11,460	11,824	12,904	13,942	152,454	150,591
2012	16,772	14,064	14,009	13,595	12,315	11,817	11,552	11,327	10,989	12,038	13,389	14,985	156,851	159,562
2013 F	17,049	14,683	14,317	14,028	12,438	11,799	11,602	11,500	11,323	12,284	13,160	14,637	158,819	161,564
2014 F	17,426	15,041	14,674	14,359	12,760	12,114	11,882	11,626	11,453	12,543	13,453	14,959	162,290	165,095
2015 F	17,789	15,370	14,998	14,677	13,056	12,400	12,165	11,900	11,721	12,707	13,676	15,225	165,685	168,549

YEC-YECL-5

Reference: Section 2 – Sales and Revenue – Lighting Sales Forecast

Request:

(a) Please provide forecast method for streetlight sales, including average usage per light for each lighting type (kW.h/year/light type) and number of lights by lighting type and by community.

(b) Please provide actual (2008-2012) and forecast (2013-2015) sales by month for each test year and rate zone (Hydro, Large Diesel, Small Diesel and Old Crow) in excel file.

Response:

(a) Forecast Method for streetlight sales:

Streetlight Energy Sales = (Number of streetlights) x (Average use per light)

Rate	Light Type	Use per light (kwh)		
		2013	2014	2015
6110	175W	72	72	72
6120	250W	97	97	97
6130	400W	157	157	157
6140	100W	40	40	40
6180	250W	101	101	101
6190	400W	158	158	158
6360	150W	59	59	59
6580	250W	101	101	101
6590	400W	158	158	158
6640	70W	27	27	27
6720	250W	97	97	97
6780	250W	101	101	101
6790	400W	158	158	158

Rate	Light Type	Number of Streetlights (average)		
		2013	2014	2015
6110	175W	0	0	0
6120	250W	22	22	22
6130	400W	0	0	0
6140	100W	3,214	3,225	3,236
6180	250W	1,243	1,280	1,317
6190	400W	21	21	21
6360	150W	374	392	410
6580	250W	105	105	105
6590	400W	53	53	53
6640	70W	104	109	114
6720	250W	32	32	32
6780	250W	15	15	15
6790	400W	15	15	15

Please note that the number of lights by community is not available, but only by rate and light type.

(b) Please refer to YEC-YECL-5(b) Attachment 1 for billed sales by month for each test year by rate zone. The lighting forecast is created by rate code and not by rate zone as all the rate zones share the same rate.

The Yukon Electrical Company Limited
Lighting Sales (MWh) by Rate Zone

Hydro Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	301	302	302	303	305	304	305	304	305	305	342	332	3,709	3,743
2009	302	303	300	300	302	308	303	303	303	333	317	317	3,692	3,654
2010	317	317	318	319	317	317	318	317	317	314	320	317	3,809	3,821
2011	318	318	318	317	318	318	314	319	330	318	318	317	3,821	3,767
2012	318	336	322	321	321	321	321	320	321	320	320	319	3,861	3,910
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Large Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	23	23	23	23	23	23	23	23	23	23	26	24	279	281
2009	22	23	23	23	23	23	23	23	23	23	23	22	271	268
2010	23	23	23	23	23	22	22	22	22	22	22	22	269	270
2011	22	22	22	22	23	22	22	22	22	22	22	22	268	265
2012	22	22	22	22	22	22	22	22	22	22	22	22	267	270
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Small Diesel Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	10	10	10	10	10	10	10	10	10	10	12	11	125	126
2009	10	10	10	10	10	10	10	10	10	10	10	10	123	122
2010	10	11	10	10	10	10	10	10	10	10	10	10	124	124
2011	10	10	10	10	10	10	10	10	10	10	10	10	124	122
2012	10	10	10	10	10	10	10	10	10	10	10	10	124	125
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Old Crow Rate Zone - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	2	2	2	2	2	2	2	2	2	2	2	2	26	26
2009	2	2	2	2	2	2	2	2	2	2	2	2	25	25
2010	2	2	2	2	2	2	2	2	2	2	2	2	25	26
2011	2	2	2	2	2	2	2	2	2	2	2	2	25	25
2012	2	2	2	2	2	2	2	2	2	2	2	2	25	26
2013 F	Not Available													
2014 F	Not Available													
2015 F	Not Available													

Total - Billed Sales

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total Billed	Total Earned
2008	336	338	337	338	340	339	340	340	340	340	381	370	4,139	4,176
2009	337	338	335	335	337	343	338	338	338	368	352	352	4,111	4,069
2010	352	352	353	354	352	352	352	352	352	349	355	352	4,228	4,241
2011	353	352	352	351	353	352	349	353	365	352	352	352	4,239	4,179
2012	353	371	357	356	356	356	355	355	355	355	355	354	4,278	4,332
2013 F	355	355	355	355	355	355	355	355	360	360	360	360	4,279	4,279
2014 F	360	360	360	360	360	360	360	360	364	364	364	364	4,334	4,334
2015 F	364	364	364	364	364	364	364	364	369	369	369	369	4,388	4,388

YEC-YECL-6 AMENDED

Reference: Section 2 – Sales and Revenue – Industrial Sales Forecast

Request:

(a) Please provide details of the industrial load forecast, including the forecast provided by Whitehorse Copper Tailings (WHCT).

(b) Please provide monthly sales and demand forecasts.

(c) Please discuss winter load requirements for WHCT, if any.

(d) Please provide details of the proposed deferral account relating to WHCT sales uncertainty, including trigger points when the difference between forecast and actual will be refunded to or collected from customers, and how YECL proposes to collect/refund the difference. Please provide examples by assuming WHCT actual sales for the test years are higher than forecast and lower than forecast.

(e) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(f) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a & b) Please refer to UCG-YECL-8(e) Attachment 1. Whitehorse Copper Tailings provided load and the approximate start-up time in which Yukon Electrical based the sales forecast on.

(c) WHCT has advised Yukon Electrical that it intends on being in operation for 9 months in a year: March to November.

(d) Unless the deferral account grows to greater than 0.5% of Yukon Electrical's revenue requirement (approximately $300,000), Yukon Electrical would propose to collect/refund the difference as part of its next GRA. If the deferral did grow to this level, Yukon Electrical would make an application to the Board to

dispense of the balance. Please refer to YEC-YECL-6(d) Attachment 1 for an example of the proposed deferral calculation assuming WHCT sales are higher than forecast or lower than forecast, as well as if WHCT does not start up operations in 2013-2015.

(e) Not confirmed. No industrial customers were forecast as part of Yukon Electrical's 2008/2009 GRA. Therefore, the requested deferral account does not reduce Yukon Electrical's risk profile but rather keeps it constant.

(f) Yukon Electrical is aware of two examples of similar deferrals used by other regulated utilities in Canada.

- Northland Utilities (NWT) Limited ("Northland") requested a very similar deferral as part of its 2008-2010 GRA. Northland did not have any industrial customers but was in discussions at the time the Application was filed with a potential mining customer, Tamerlane Ventures Inc., regarding the provision of electrical service starting in the fourth quarter of 2008. Northland applied for a deferral account to capture revenues and costs associated with providing service to the potential new industrial customer, as the start-up date and load could not be reasonably forecast. In Decision 25-2008, the NWTPUB approved this deferral.

- In the Yukon in 1998, the Board ordered the creation of a deferral account related to the sales of Yukon Energy to the Faro mine site under Rate Schedule 34. In Board Order 1998-5, the Board stated:

> All revenue derived from Rate Schedule 34, less reasonable incremental costs associated with supplying the Faro mine site under this rate schedule, shall be placed in a deferral account for subsequent application to the benefit of customers as directed by the Board.

Other than the above examples, Yukon Electrical is not aware of any other similar deferral accounts used by other regulated utilities in Canada that would be applicable to the unique start-up timing and load uncertainties currently being faced by Yukon Electrical as part of this Application.

The Yukon Electrical Company Limited
Sample Calculation of Proposed Whitehorse Copper Tailings Deferral

	2013	2014	2015
Forecast Load (MWh) (per Schedule 2.1 of the Application)	1,025	4,620	4,620
Forecast Revenue per kWh (per Schedule 2.1 of the Application)	$ 0.1391	$ 0.1326	$ 0.1326
Forecast Purchase Power Rate per kWh (per Schedule 3.1 of the Application)	$ 0.0830	$ 0.0830	$ 0.0830
Forecast Line Losses (Per Schedule 3.2 of the Application)	6.2%	6.2%	6.2%
Scenario #1 - Whitehorse Copper Load is 50% Lower Than Forecast			
Actual Load (MWh)	512	2,310	2,310
Change in Revenues	$ 71,289	$ 306,198	$ 306,198
Change in Purchase Power Costs	$ (45,155)	$ (203,568)	$ (203,568)
Amount to Be Collected From (Refunded To) Customers	$ 26,134	$ 102,630	$ 102,630
Scenario #2 - Whitehorse Copper Load is 50% Higher Than Forecast			
Actual Load (MWh)	1,537	6,930	6,930
Change in Revenues	$ (71,289)	$ (306,198)	$ (306,198)
Change in Purchase Power Costs	$ 45,155	$ 203,568	$ 203,568
Amount to Be Collected From (Refunded To) Customers	$ (26,134)	$ (102,630)	$ (102,630)
Scenario #3 - Whitehorse Copper Does Not Start Operations in the Test Period			
Actual Load (MWh)	-	-	-
Change in Revenues	$ 142,579	$ 612,396	$ 612,396
Change in Purchase Power Costs	$ (90,310)	$ (407,136)	$ (407,136)
Amount to Be Collected From (Refunded To) Customers	$ 52,269	$ 205,260	$ 205,260

YEC-YECL-7

Reference: Section 2 – Sales and Revenue – YECL/YEC Retail Revenue

Request:

(a) Please provide details of the YECL revenue forecast calculation by rate class for each test year, including assumed average rate per kW.h, assumed sales and revenue by rate blocks for each rate class and assumed sales and revenue by government and non-government customer type for each rate class.

(b) Please provide details of YEC revenue forecast calculation for test year as shown in Schedule 2.1.

Response:

(a) Please refer to YEC-YECL-7(a) Attachment 1 for the requested calculations.

(b) Please refer to YEC-YECL-7(b) Attachment 1 for the details of the Yukon Energy revenue forecast for the test years as provided by Yukon Energy by e-mail on May 3, 2013.

RESIDENTIAL AND COMMERCIAL RATES

(Applies to 2013-2015 Revenue on Existing Rates)

Existing Rates	Customer Charge	Energy $/kWh Block 1	Energy $/kWh Block 2	Energy $/kWh Block 3	Energy $/kWh Block 4	Demand Charge per kW
1160 - Res-Hydro Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1180 - Res-Hydro Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1260 - Res-Small Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1280 - Res-Small Diesel Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1360 - Res-Large Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.1399		$0
1380 - Res-Large Diesel Govt	$18.47	$0.1647	$0.1747	$0.1885		$0
1460 - Res-Old Crow Diesel Non-Govt	$14.65	$0.1214	$0.1282	$0.3077		$0
1480 - Res-Old Crow Diesel Govt	$18.47	$0.1647	$0.1747	$0.4145		$0
2160 - Com-Hydro Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2170 - Com-Hydro Govt-Muni	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2180 - Com-Hydro Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.1286	$12.31
2260 - Com-Small Diesel Non-govt	$0	$0.1000	$0.1288	$0.1568	$0.1522	$7.39
2280 - Com-Small Diesel Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.1522	$12.31
2360 - Com-Large Diesel Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2370 - Com-Large Diesel Govt-Muni	$0	$0.1000	$0.1288	$0.1568	$0.1286	$7.39
2380 - Com-Large Diesel Govt-Federal	$0	$0.1381	$0.1500	$0.2000	$0.1286	$12.31
2460 - Com-Old Crow Diesel Non-Govt	$0	$0.1000	$0.1288	$0.1568	$0.3172	$7.39
2480 - Com-Old Crow Diesel Govt-Fed	$0	$0.1381	$0.1500	$0.2000	$0.3172	$12.31

RESIDENTIAL AND COMMERCIAL 2013 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2013 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	155,628	110,819,077	27,065,347	3,496,429		141,380,853	
1180 - Res-Hydro Govt	2,086	1,270,414	334,489	32,514		1,637,417	
1260 - Res-Small Diesel Non-Govt	1,831	967,445	146,469	8,162		1,122,076	
1280 - Res-Small Diesel Govt	204	168,610	44,088	2,068		214,767	
1360 - Res-Large Diesel Non-Govt	8,022	5,134,912	900,803	59,411		6,095,126	
1380 - Res-Large Diesel Govt	408	218,770	29,118	2,369		250,257	
1460 - Res-Old Crow Diesel Non-Govt	1,608	898,499	63,134	16,313		977,945	
1480 - Res-Old Crow Diesel Govt	120	71,337	24,495	18,525		114,358	
Total - Residential		**119,549,065**	**28,607,944**	**3,635,791**		**151,792,800**	
2160 - Com-Hydro Non-Govt	23,575	29,622,363	35,549,026	3,998,752	22,429,035	91,599,177	415,616
2170 - Com-Hydro Govt-Muni	2,126	1,807,453	3,725,823	674,590	6,743,570	12,951,435	51,654
2180 - Com-Hydro Govt-Fed	4,595	5,322,765	12,962,502	2,772,624	26,089,167	47,147,058	162,551
2260 - Com-Small Diesel Non-govt	648	706,226	556,920	2,751	365	1,266,262	7,114
2280 - Com-Small Diesel Govt-Fed	539	415,716	273,122	568	0	689,406	4,182
2360 - Com-Large Diesel Non-Govt	1,758	2,269,788	2,264,937	211,298	409,684	5,155,707	27,980
2370 - Com-Large Diesel Govt-Muni	204	125,985	277,655	20,526	66,438	490,605	2,076
2380 - Com-Large Diesel Govt-Federal	457	376,707	656,512	117,142	233,511	1,383,872	6,701
2460 - Com-Old Crow Diesel Non-Govt	264	296,115	328,430	1,824	0	626,369	2,803
2480 - Com-Old Crow Diesel Govt-Fed	239	127,785	125,696	1,007	0	254,488	1,677
Total - Commercial		**41,070,903**	**56,720,623**	**7,801,081**	**55,971,771**	**161,564,378**	**682,353**

2013 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,279,950	$13,453,436	$3,469,778	$489,150		$17,412,364		$19,692,314
1180 - Res-Hydro Govt	$38,528	$209,237	$58,435	$6,129		$273,801		$312,330
1260 - Res-Small Diesel Non-Govt	$26,824	$117,448	$18,777	$1,142		$137,367		$164,191
1280 - Res-Small Diesel Govt	$3,768	$27,770	$7,702	$390		$35,862		$39,630
1360 - Res-Large Diesel Non-Govt	$117,522	$623,378	$115,483	$8,312		$747,173		$864,695
1380 - Res-Large Diesel Govt	$7,536	$36,031	$5,087	$447		$41,565		$49,101
1460 - Res-Old Crow Diesel Non-Govt	$23,557	$109,078	$8,094	$5,019		$122,191		$145,748
1480 - Res-Old Crow Diesel Govt	$2,216	$11,749	$4,279	$7,679		$23,707		$25,924
Total - Residential	**2,499,902**	**14,588,128**	**3,687,635**	**518,267**		**18,794,030**		**$21,293,933**
2160 - Com-Hydro Non-Govt		$2,962,236	$4,578,715	$627,004	$2,884,374	$11,052,329	$3,071,403	$14,123,732
2170 - Com-Hydro Govt-Muni		$180,745	$479,886	$105,776	$867,223	$1,633,630	$381,723	$2,015,353
2180 - Com-Hydro Govt-Fed		$735,074	$1,944,375	$554,525	$3,355,067	$6,589,041	$2,000,998	$8,590,038
2260 - Com-Small Diesel Non-govt		$70,623	$71,731	$431	$56	$142,841	$52,571	$195,412
2280 - Com-Small Diesel Govt-Fed		$57,410	$40,968	$114	$0	$98,492	$51,476	$149,969
2360 - Com-Large Diesel Non-Govt		$226,979	$291,724	$33,131	$52,685	$604,520	$206,772	$811,291
2370 - Com-Large Diesel Govt-Muni		$12,599	$35,762	$3,219	$8,544	$60,123	$15,341	$75,464
2380 - Com-Large Diesel Govt-Federal		$52,023	$98,477	$23,428	$30,030	$203,958	$82,484	$286,442
2460 - Com-Old Crow Diesel Non-Govt		$29,611	$42,302	$286	$0	$72,199	$20,714	$92,914
2480 - Com-Old Crow Diesel Govt-Fed		$17,647	$18,854	$201	$0	$36,703	$20,645	$57,348
Total - Commercial	**$0**	**$4,344,948**	**$7,602,794**	**$1,348,115**	**$7,197,978**	**$20,493,836**	**$5,904,127**	**$26,397,963**

RESIDENTIAL AND COMMERCIAL 2014 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2014 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	158,294	112,706,361	27,524,409	3,563,289		143,794,058	
1180 - Res-Hydro Govt	2,122	1,294,093	338,704	32,972		1,665,769	
1260 - Res-Small Diesel Non-Govt	1,864	985,465	148,308	8,111		1,141,885	
1280 - Res-Small Diesel Govt	204	170,831	44,713	2,306		217,850	
1360 - Res-Large Diesel Non-Govt	8,160	5,227,400	912,013	59,836		6,199,250	
1380 - Res-Large Diesel Govt	414	222,660	29,462	2,354		254,477	
1460 - Res-Old Crow Diesel Non-Govt	1,630	909,581	65,258	16,688		991,527	
1480 - Res-Old Crow Diesel Govt	120	72,256	24,803	18,887		115,946	
Total - Residential		**121,588,648**	**29,087,671**	**3,704,443**		**154,380,761**	
2160 - Com-Hydro Non-Govt	23,879	30,250,205	36,303,740	4,083,213	22,903,197	93,540,355	427,938
2170 - Com-Hydro Govt-Muni	2,152	1,845,818	3,804,913	688,962	6,885,943	13,225,636	52,737
2180 - Com-Hydro Govt-Fed	4,652	5,435,232	13,237,909	2,831,732	26,644,165	48,149,038	166,342
2260 - Com-Small Diesel Non-govt	659	717,508	565,815	2,796	371	1,286,489	7,228
2280 - Com-Small Diesel Govt-Fed	545	422,152	277,323	576	0	700,051	4,247
2360 - Com-Large Diesel Non-Govt	1,782	2,356,146	2,352,142	219,486	425,005	5,352,778	29,037
2370 - Com-Large Diesel Govt-Muni	204	130,811	288,660	21,513	69,369	510,354	2,153
2380 - Com-Large Diesel Govt-Federal	461	390,849	681,749	121,684	243,074	1,437,355	7,741
2460 - Com-Old Crow Diesel Non-Govt	264	300,198	332,957	1,850	0	635,005	2,842
2480 - Com-Old Crow Diesel Govt-Fed	240	129,549	127,428	1,021	0	257,997	1,700
Total - Commercial		**41,978,466**	**57,972,634**	**7,972,834**	**57,171,124**	**165,095,058**	**701,964**

2014 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,319,007	$13,682,552	$3,528,629	$498,504		$17,709,686		$20,028,693
1180 - Res-Hydro Govt	$39,193	$213,137	$59,172	$6,215		$278,524		$317,717
1260 - Res-Small Diesel Non-Govt	$27,308	$119,635	$19,013	$1,135		$139,783		$167,091
1280 - Res-Small Diesel Govt	$3,768	$28,136	$7,811	$435		$36,382		$40,150
1360 - Res-Large Diesel Non-Govt	$119,544	$634,606	$116,920	$8,371		$759,898		$879,442
1380 - Res-Large Diesel Govt	$7,647	$36,672	$5,147	$444		$42,263		$49,910
1460 - Res-Old Crow Diesel Non-Govt	$23,880	$110,423	$8,366	$5,135		$123,924		$147,804
1480 - Res-Old Crow Diesel Govt	$2,216	$11,901	$4,333	$7,828		$24,062		$26,279
Total - Residential	**2,542,562**	**14,837,063**	**3,749,392**	**528,067**		**19,114,521**		**$21,657,084**
2160 - Com-Hydro Non-Govt		$3,025,020	$4,675,922	$640,248	$2,945,351	$11,286,541	$3,162,461	$14,449,002
2170 - Com-Hydro Govt-Muni		$184,582	$490,073	$108,029	$885,532	$1,668,216	$389,726	$2,057,943
2180 - Com-Hydro Govt-Fed		$750,606	$1,985,686	$566,346	$3,426,440	$6,729,078	$2,047,667	$8,776,745
2260 - Com-Small Diesel Non-govt		$71,751	$72,877	$438	$56	$145,123	$53,411	$198,534
2280 - Com-Small Diesel Govt-Fed		$58,299	$41,598	$115	$0	$100,013	$52,276	$152,289
2360 - Com-Large Diesel Non-Govt		$235,615	$302,956	$34,415	$54,656	$627,641	$214,584	$842,226
2370 - Com-Large Diesel Govt-Muni		$13,081	$37,179	$3,373	$8,921	$62,555	$15,913	$78,467
2380 - Com-Large Diesel Govt-Federal		$53,976	$102,262	$24,337	$31,259	$211,835	$95,292	$307,127
2460 - Com-Old Crow Diesel Non-Govt		$30,020	$42,885	$290	$0	$73,195	$21,001	$94,195
2480 - Com-Old Crow Diesel Govt-Fed		$17,891	$19,114	$204	$0	$37,209	$20,930	$58,139
Total - Commercial	**$0**	**$4,440,840**	**$7,770,553**	**$1,377,797**	**$7,352,215**	**$20,941,405**	**$6,073,262**	**$27,014,666**

RESIDENTIAL AND COMMERCIAL 2015 BILLING DETERMINANTS & REVENUE ON EXISTING RATES

2015 Billing Determinants	#Cust Billed in the Year	kWh Energy Block 1	kWh Energy Block 2	kWh Energy Block 3	kWh Energy Block 4	kWh Energy Total Sales	kW Total Demand
1160 - Res-Hydro Non-Govt	160,997	114,633,102	27,994,941	3,624,202		146,252,245	
1180 - Res-Hydro Govt	2,158	1,316,359	344,534	33,540		1,694,433	
1260 - Res-Small Diesel Non-Govt	1,896	1,002,560	150,882	8,251		1,161,693	
1280 - Res-Small Diesel Govt	213	173,250	45,344	2,340		220,933	
1360 - Res-Large Diesel Non-Govt	8,303	5,318,936	928,005	60,887		6,307,828	
1380 - Res-Large Diesel Govt	420	226,540	29,976	2,396		258,912	
1460 - Res-Old Crow Diesel Non-Govt	1,659	925,182	66,379	16,974		1,008,536	
1480 - Res-Old Crow Diesel Govt	120	73,495	25,229	19,211		117,935	
Total - Residential		**123,669,424**	**29,585,289**	**3,767,800**		**157,022,514**	
2160 - Com-Hydro Non-Govt	24,258	30,893,773	37,075,522	4,170,087	23,392,338	95,531,720	438,917
2170 - Com-Hydro Govt-Muni	2,185	1,885,031	3,885,913	703,601	7,032,065	13,506,610	54,053
2180 - Com-Hydro Govt-Fed	4,723	5,551,590	13,520,338	2,892,006	27,212,458	49,176,392	170,511
2260 - Com-Small Diesel Non-govt	670	729,787	575,504	2,844	377	1,308,511	7,351
2280 - Com-Small Diesel Govt-Fed	553	429,167	281,926	586	0	711,678	4,317
2360 - Com-Large Diesel Non-Govt	1,811	2,390,960	2,386,893	222,723	431,278	5,431,854	29,466
2370 - Com-Large Diesel Govt-Muni	205	132,685	292,795	21,822	70,367	517,669	2,184
2380 - Com-Large Diesel Govt-Federal	468	396,476	691,565	123,434	246,578	1,458,053	7,829
2460 - Com-Old Crow Diesel Non-Govt	264	304,573	337,809	1,877	0	644,259	2,883
2480 - Com-Old Crow Diesel Govt-Fed	240	131,437	129,285	1,036	0	261,757	1,725
Total - Commercial		**42,845,478**	**59,177,550**	**8,140,016**	**58,385,460**	**168,548,504**	**719,237**

2015 Revenue on Existing Rates	Customer Revenue	Energy Revenue Block 1	Energy Revenue Block 2	Energy Revenue Block 3	Energy Revenue Block 4	Total Energy Revenue	Demand Charge	Total Revenue
1160 - Res-Hydro Non-Govt	$2,358,606	$13,916,459	$3,588,951	$507,026		$18,012,436		$20,371,042
1180 - Res-Hydro Govt	$39,858	$216,804	$60,190	$6,322		$283,317		$323,175
1260 - Res-Small Diesel Non-Govt	$27,776	$121,711	$19,343	$1,154		$142,208		$169,985
1280 - Res-Small Diesel Govt	$3,934	$28,534	$7,922	$441		$36,897		$40,831
1360 - Res-Large Diesel Non-Govt	$121,639	$645,719	$118,970	$8,518		$773,207		$894,846
1380 - Res-Large Diesel Govt	$7,757	$37,311	$5,237	$452		$43,000		$50,757
1460 - Res-Old Crow Diesel Non-Govt	$24,304	$112,317	$8,510	$5,223		$126,050		$150,354
1480 - Res-Old Crow Diesel Govt	$2,216	$12,105	$4,407	$7,963		$24,475		$26,691
Total - Residential	**2,586,092**	**15,090,960**	**3,813,530**	**537,099**		**19,441,589**		**$22,027,681**
2160 - Com-Hydro Non-Govt		$3,089,377	$4,775,327	$653,870	$3,008,255	$11,526,829	$3,243,594	$14,770,423
2170 - Com-Hydro Govt-Muni		$188,503	$500,506	$110,325	$904,324	$1,703,657	$399,455	$2,103,112
2180 - Com-Hydro Govt-Fed		$766,675	$2,028,051	$578,401	$3,499,522	$6,872,649	$2,098,987	$8,971,635
2260 - Com-Small Diesel Non-govt		$72,979	$74,125	$446	$57	$147,607	$54,326	$201,932
2280 - Com-Small Diesel Govt-Fed		$59,268	$42,289	$117	$0	$101,674	$53,145	$154,819
2360 - Com-Large Diesel Non-Govt		$239,096	$307,432	$34,923	$55,462	$636,913	$217,755	$854,669
2370 - Com-Large Diesel Govt-Muni		$13,269	$37,712	$3,422	$9,049	$63,451	$16,141	$79,592
2380 - Com-Large Diesel Govt-Federal		$54,753	$103,735	$24,687	$31,710	$214,885	$96,375	$311,260
2460 - Com-Old Crow Diesel Non-Govt		$30,457	$43,510	$294	$0	$74,261	$21,307	$95,568
2480 - Com-Old Crow Diesel Govt-Fed		$18,151	$19,393	$207	$0	$37,751	$21,235	$58,986
Total - Commercial	**$0**	**$4,532,528**	**$7,932,078**	**$1,406,692**	**$7,508,379**	**$21,379,677**	**$6,222,320**	**$27,601,997**

INDUSTRIAL 2013, 2014 and 2015 RATES, BILLING DETERMINANTS & REVENUE ON EXISTING RATES

Industrial Rate	Demand Charge per kVA	Energy $/kWh Block 1	kVA Total Billing Demand	kWh Energy	Demand Revenue	Energy Revenue	Total Revenue
2013 - 39 - Industrial Primary	$15.94	$0.0808	3,750	1,024,800	$59,775	$82,804	$142,579
2014 - 39 - Industrial Primary	$15.94	$0.0808	15,000	4,620,000	$239,100	$373,296	$612,396
2015 - 39 - Industrial Primary	$15.94	$0.0808	15,000	4,620,000	$239,100	$373,296	$612,396

LIGHTING 2013, 2014 and 2015 RATES, BILLING DETERMINANTS & REVENUE ON EXISTING RATES

Street Lights Rates	Watts	Mthly Customer Charge	Mthly Demand Charge per Watt	# Cust Billed in 2013	# Cust Billed in 2014	# Cust Billed in 2015	Street Light Revenue 2013	Street Light Revenue 2014	Street Light Revenue 2015
6110 - Mercury Vapor	175	$7.83	$0.0496	0	0	0	$0	$0	$0
6120 - Mercury Vapor	250	$7.83	$0.0496	264	264	264	$5,341	$5,341	$5,341
6130 - Mercury Vapor	400	$7.83	$0.0496	0	0	0	$0	$0	$0
6140 - High Pressure Sodium	100	$7.83	$0.0496	38,564	38,696	38,828	$493,234	$494,922	$496,610
6180 - High Pressure Sodium	250	$7.83	$0.0496	14,920	15,364	15,808	$301,832	$310,814	$319,796
6190 - High Pressure Sodium	400	$7.83	$0.0496	252	252	252	$6,973	$6,973	$6,973
6360 - High Pressure Sodium	150	$7.83	$0.0496	4,488	4,704	4,920	$68,532	$71,830	$75,128
6580 - High Pressure Sodium-High Mast	250	$9.10	$0.0496	1,260	1,260	1,260	$27,090	$27,090	$27,090
6590 - High Pressure Sodium-High Mast	400	$9.10	$0.0496	636	636	636	$18,406	$18,406	$18,406
6640 - High Pressure Sodium	70	$7.83	$0.0496	1,244	1,304	1,364	$14,057	$14,735	$15,413
6720 - Mercury Vapor Energy Only	250	$19.05	$0.000	384	384	384	$7,315	$7,315	$7,315
6780 - High Pressure Sodium Energy Only	250	$19.05	$0.000	180	180	180	$3,429	$3,429	$3,429
6790 - High Pressure Sodium Energy Only	400	$29.13	$0.000	180	180	180	$5,243	$5,243	$5,243
Total							$951,451	$966,098	$980,745

Private Lights Rates	Watts	Mthly Customer Charge	# Cust Billed in 2013	# Cust Billed in 2014	# Cust Billed in 2015	Street Light Revenue 2013	Street Light Revenue 2014	Street Light Revenue 2015
7100 - Mercury Vapor - Regular	175	$17.46	1,440	1,368	1,296	$25,142	$23,885	$22,628
7120 - Mercury Vapor - E&M	175	$12.15	0	0	0	$0	$0	$0
7130 - Mercury Vapor - Metered	175	$9.81	92	80	68	$903	$785	$667
7200 - High Pressure Sodium - Regular	250	$21.35	36	36	36	$769	$769	$769
7300 - Mercury Vapor - Regular	400	$28.36	0	0	0	$0	$0	$0
7400 - Mercury Vapor Flood - Regular	400	$31.32	708	672	636	$22,175	$21,047	$19,920
7420 - Mercury Vapor Flood - E&M	400	$21.85	36	36	36	$787	$787	$787
7430 - Mercury Vapor Flood - Metered	400	$12.63	36	36	36	$455	$455	$455
7500 - High Pressure Sodium - Regular	100	$14.33	4,532	4,520	4,508	$64,944	$64,772	$64,600
7520 - High Pressure Sodium - E&M	100	$7.95	3,684	3,720	3,756	$29,288	$29,574	$29,860
7530 - High Pressure Sodium - Metered	100	$9.04	96	96	96	$868	$868	$868
Total						$145,329	$142,940	$140,552

YEC ESTIMATED REVENUE FOR 2013-2015

2013

					11.87%	8.19%	
SALES				**Sales ($)**	**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh			1,815,000.00	215,440.50		2,030,440.50
General Service	kWh			3,735,000.00	443,344.50		4,178,344.50
Industrial	kWh			4,787,000.00		392,055.30	5,179,055.30
Streetlights	kWh			88,000.00	10,445.60		98,445.60
Space	kWh			4,000.00	474.80		4,474.80
				10,429,000.00	669,705.40		11,490,760.70

2014

					11.87%	**8.19%**	
SALES		**2014**			**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh	13,261,660	14.63	1,940,180.86	230,299.47		2,170,480.33
General Service	kWh	22,750,253	16.51	3,756,066.77	445,845.13		4,201,911.90
Industrial	kWh	54,070,520	11.79	6,374,914.31		522,105.48	6,897,019.79
Streetlights	kWh	297,460	31.55	93,848.63	11,139.83		104,988.46
Space	kWh	15,000	26.76	4,014.00	476.46		4,490.46
				12,169,024.57	687,760.89		13,378,890.94

2015

					11.87%	**8.19%**	
SALES		**2015**			**Rider J (non-ind)**	**Rider J (Ind)**	
Residential	kWh	13,305,048	14.63	1,946,528.52	231,052.94		2,177,581.46
General Service	kWh	22,815,497	16.51	3,766,838.55	447,123.74		4,213,962.29
Industrial	kWh	55,070,520	11.79	6,492,814.31		531,761.49	7,024,575.80
Streetlights	kWh	297,647	31.55	93,907.63	11,146.84		105,054.46
Space	kWh	15,000	26.76	4,014.00	476.46		4,490.46
				12,304,103.01	689,799.97		13,525,664.47

YEC-YECL-8

Reference: Section 3 – Purchase Power – Generation and Purchased Power forecast

Request:

(a) Please provide details of requested Purchase Power Flow Through deferral account, including:

(i) Please confirm the balance of this account is zero.

(ii) Please confirm that the Purchase Power Flow Through deferral account requires a collection mechanism to be implemented and approval by the YUB prior to collecting or refunding any balances.

(iii) Please provide any updates regarding the status of any future collection mechanism to be proposed by YECL.

Response:

(a) (i) Yukon Electrical is able to confirm the balance was zero at least with respect to what it knew as of December 31, 2012. It is presently unclear as to whether a final Board decision on Wholesale Rate Schedule 42 and the associated Energy Reconciliation Adjustment (ERA) will, or will not, result in a deferral balance as of December 31, 2012 and for periods thereafter.

(ii) Confirmed.

(iii) There is no update regarding the status of any future collection mechanism.

YEC-YECL-9

Reference: Section 4 – Fuel Cost – Fuel Price Flow Through deferral account

Request:

(a) Please provide details of any consultation with YEC and other stakeholders regarding the Fuel Price Flow Through deferral account. If no consultations have taken place, please explain why?

(b) Please provide details of the Fuel Price Flow Through deferral account by providing examples for next five years:

(i) assuming diesel/LNG fuel prices are higher than GRA approved; and

(ii) assuming diesel/LNG fuel prices are lower than GRA approved

Response:

(a) Yukon Electrical did not have any consultation with YEC or other parties regarding Yukon Electrical's proposed change to the Fuel Price Flow Through Deferral for Watson Lake fuel. While Yukon Electrical consulted parties on a variety of areas issues associated with this Application, (please refer to UCG-YECL-2 for discussion of the consultation that took place) this particular deferral request is not complex in nature and is best served by having it reviewed and tested as part of this Application.

(b) (i) Please refer to YEC-YECL-9(b) Attachment 1.

(ii) Please refer to YEC-YECL-9(b) Attachment 2.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Fuel Price Flow Through Example - Diesel/LNG Prices Are Higher Than GRA Approved

Line No.	Description	Ref:	Approved Parameters 2013	2014	2015	2016	2017	Fuel Price +10% per litre (All Years)
	Average Cost (in cents per litre)							
1	Watson Lake		101.76	101.76	101.76	101.76	101.76	111.93
2	Beaver Creek		116.53	116.53	116.53	116.53	116.53	128.18
3	Destruction Bay		115.41	115.41	115.41	115.41	115.41	126.95
4	Old Crow		218.44	218.44	218.44	218.44	218.44	240.29
5	Pelly Crossing (Standby as of 2009)		-	-	-	-	-	-
6	Swift River		105.63	105.63	105.63	105.63	105.63	116.19
7	Standby Units		89.56	89.56	89.56	89.56	89.56	98.51
	Generation (MWh)							
8	Watson Lake		15,085	15,261	15,267	15,267	15,267	
9	Beaver Creek		1,800	1,832	1,834	1,834	1,834	
10	Destruction Bay		1,826	1,860	1,862	1,862	1,862	
11	Old Crow		2,083	2,114	2,114	2,114	2,114	
12	Pelly Crossing		-	-	-	-	-	
13	Swift River		263	267	268	268	268	
14	Standby Units		70	70	70	70	70	
15			21,127	21,405	21,415	21,415	21,415	
16	Net Heat Rate (kWh/litre)							
17	Watson Lake		n/a	n/a	n/a	n/a	n/a	
18	Beaver Creek	GRA Approved	3.59	3.59	3.59	3.59	3.59	
19	Destruction Bay	GRA Approved	3.58	3.58	3.58	3.58	3.58	
20	Old Crow	GRA Approved	3.60	3.60	3.60	3.60	3.60	
21	Pelly Crossing	GRA Approved	-	-	-	-	-	
22	Swift River	GRA Approved	2.79	2.79	2.79	2.79	2.79	
23	Standby Units	GRA Approved	3.02	3.02	3.02	3.02	3.02	
24	GRA Approved Litres for Fuel Deferral							
25	Watson Lake (Actual Litres - Diesel + LNG Converted to Litre Diesel Equivalent)		3,988	4,034	4,036	4,036	4,036	
26	Beaver Creek	Line 9 / Line 18	502	511	512	512	512	
27	Destruction Bay	Line 10 / Line 19	510	520	520	520	520	
28	Old Crow	Line 11 / Line 20	578	587	587	587	587	
29	Pelly Crossing	Line 12 / Line 21	-	-	-	-	-	
30	Swift River	Line 13 / Line 22	94	96	96	96	96	
31	Standby Units	Line 14 / Line 23	20	20	20	20	20	
32			5,692	5,767	5,771	5,771	5,771	
33	Fuel Variance Deferral	Difference in Approved v. Actual Price * Litres						
34								
35	Watson Lake	(Line 1 : Average Cost - Actual Cost) * Line 25	(405.80)	(410.48)	(410.69)	(410.69)	(410.69)	
36	Beaver Creek	(Line 2 : Average Cost - Actual Cost) * Line 26	(58.48)	(59.55)	(59.61)	(59.61)	(59.61)	
37	Destruction Bay	(Line 3 : Average Cost - Actual Cost) * Line 27	(58.89)	(59.98)	(60.04)	(60.04)	(60.04)	
38	Old Crow	(Line 4 : Average Cost - Actual Cost) * Line 28	(126.21)	(128.12)	(128.13)	(128.13)	(128.13)	
39	Pelly Crossing	(Line 5 : Average Cost - Actual Cost) * Line 29	-	-	-	-	-	
40	Swift River	(Line 6 : Average Cost - Actual Cost) * Line 30	(9.96)	(10.11)	(10.15)	(10.15)	(10.15)	
41	Standby Units	(Line 7 : Average Cost - Actual Cost) * Line 31	(1.81)	(1.81)	(1.81)	(1.81)	(1.81)	
	Amount to be Collected from Customers		(661)	(670)	(670)	(670)	(670)	

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Fuel Price Flow Through Example - Diesel/LNG Prices Are Lower Than GRA Approved

Line No.	Description	Ref:	Approved Parameters 2013	2014	2015	2016	2017	Fuel Price -10% per litre (All Years)
	Average Cost (in cents per litre)							
1	Watson Lake		101.76	101.76	101.76	101.76	101.76	91.58
2	Beaver Creek		116.53	116.53	116.53	116.53	116.53	104.88
3	Destruction Bay		115.41	115.41	115.41	115.41	115.41	103.87
4	Old Crow		218.44	218.44	218.44	218.44	218.44	196.60
5	Pelly Crossing (Standby as of 2009)		-	-	-	-	-	-
6	Swift River		105.63	105.63	105.63	105.63	105.63	95.07
7	Standby Units		89.56	89.56	89.56	89.56	89.56	80.60
	Generation (MWh)							
8	Watson Lake		15,085	15,261	15,267	15,267	15,267	
9	Beaver Creek		1,800	1,832	1,834	1,834	1,834	
10	Destruction Bay		1,826	1,860	1,862	1,862	1,862	
11	Old Crow		2,083	2,114	2,114	2,114	2,114	
12	Pelly Crossing		-	-	-	-	-	
13	Swift River		263	267	268	268	268	
14	Standby Units		70	70	70	70	70	
15			21,127	21,405	21,415	21,415	21,415	
16	Net Heat Rate (kWh/litre)							
17	Watson Lake		n/a	n/a	n/a	n/a	n/a	
18	Beaver Creek	GRA Approved	3.59	3.59	3.59	3.59	3.59	
19	Destruction Bay	GRA Approved	3.58	3.58	3.58	3.58	3.58	
20	Old Crow	GRA Approved	3.60	3.60	3.60	3.60	3.60	
21	Pelly Crossing	GRA Approved	-	-	-	-	-	
22	Swift River	GRA Approved	2.79	2.79	2.79	2.79	2.79	
23	Standby Units	GRA Approved	3.02	3.02	3.02	3.02	3.02	
24	GRA Approved Litres for Fuel Deferral							
25	Watson Lake (Actual Litres - Diesel + LNG Converted to Litre Diesel Equivalent)		3,988	4,034	4,036	4,036	4,036	
26	Beaver Creek	Line 9 / Line 18	502	511	512	512	512	
27	Destruction Bay	Line 10 / Line 19	510	520	520	520	520	
28	Old Crow	Line 11 / Line 20	578	587	587	587	587	
29	Pelly Crossing	Line 12 / Line 21	-	-	-	-	-	
30	Swift River	Line 13 / Line 22	94	96	96	96	96	
31	Standby Units	Line 14 / Line 23	20	20	20	20	20	
32			5,692	5,767	5,771	5,771	5,771	
33	Fuel Variance Deferral	Difference in Approved v. Actual Price * Litres						
34								
35	Watson Lake	(Line 1 : Average Cost - Actual Cost) * Line 25	405.80	410.48	410.69	410.69	410.69	
36	Beaver Creek	(Line 2 : Average Cost - Actual Cost) * Line 26	58.48	59.55	59.61	59.61	59.61	
37	Destruction Bay	(Line 3 : Average Cost - Actual Cost) * Line 27	58.89	59.98	60.04	60.04	60.04	
38	Old Crow	(Line 4 : Average Cost - Actual Cost) * Line 28	126.21	128.12	128.13	128.13	128.13	
39	Pelly Crossing	(Line 5 : Average Cost - Actual Cost) * Line 29	-	-	-	-	-	
40	Swift River	(Line 6 : Average Cost - Actual Cost) * Line 30	9.96	10.11	10.15	10.15	10.15	
41	Standby Units	(Line 7 : Average Cost - Actual Cost) * Line 31	1.81	1.81	1.81	1.81	1.81	
	Amount to be Refunded to Customers		**661**	**670**	**670**	**670**	**670**	

YEC-YECL-10

Reference: Defined Benefit Deferral Account

Request:

(a) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(b) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) Not confirmed in the context of this GRA as compared to the 2008-2009 GRA. When Yukon Electrical filed its last GRA in 2008, Federal pension regulations in place at that time required updated actuarial valuations to be completed for defined benefit ("DB") pension plans once every three years. An actuarial valuation for the DB plan that Yukon Electrical participates in was completed as at December 31, 2006 to determine the required funding for the years 2007-2009. The level of the required contributions was known for the three year period 2007-2009 which, in turn, covered the test period 2008-2009.

In 2010, regulations amending certain Federal pension regulations came into force. As a result, Federally-regulated pension plans, such as the plan in which Yukon Electrical participates, are now generally required to file updated actuarial valuation reports on an annual basis. As the valuation reports determine the required funding for the next year, this means that Yukon Electrical's required contributions will fluctuate on a yearly basis throughout the 2013-2015 test period. The required contributions can both increase or decrease depending on market conditions and the performance of the pension plan assets in any year. That means that there is forecast risk for both Yukon Electrical (in the case of an increase in required contributions over the amounts included in Yukon Electrical's revenue requirement) and the ratepayer (in the case of a decrease in required contributions over the amounts included in Yukon Electrical's revenue requirement) if a deferral account is not approved. To provide further context for the need for this deferral, Yukon Electrical's contributions between 2006 and 2012 have varied between a low of $0 per year and a high of $1,268,000 per year.

(b) Yukon Electrical has not completed an exhaustive search of other utilities in Canada with similar deferral accounts. Yukon Electrical is, however, able to advise that both Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited have similar deferral accounts approved that cover all increases or decreases to required cash contributions to the defined benefit pension plan as compared to forecast.

YEC-YECL-11

Reference: Section 7 – Depreciation – Depreciation Expense

Request:

(a) Please reconcile the depreciation rates on schedules 7.2 -7.4 to the Depreciation Study results performed by Gannett Fleming. Please explain if any difference.

(b) Please provide a comparison by account of the proposed depreciation rates to the last approved depreciation rates.

(c) Please provide schedules using YECL's last approved depreciation rates similar to schedules 7.2-7.4.

(d) Please identify the amounts included as expense in the 2013-15 GRA revenue requirements with respect to net salvage costs. Indicate under which account or category these forecast expenses are included.

Response:

(a) The Depreciation Study results performed by Gannett Fleming and provided in Section 7, Attachment 1 are based on its depreciation analysis as of December 31, 2011. The results of Gannett Fleming's 2011 study produced depreciation parameters of Iowa Curve, average service life, and net salvage percentage. To more accurately reflect the actual depreciation rates that will be used for actual 2013-2015 data, Yukon Electrical has applied Gannett Fleming's recommended depreciation parameters to Yukon Electrical's forecast year end balances.

(b) The YUB approves depreciation parameters of Iowa Curve, Average Service Life and Net Salvage Percentages. The depreciation rates are the result of the application of these recommended depreciation parameters to forecast balances. Please refer to YEC-YECL-11(b) Attachments 1 to 3 for a comparison of 2013-2015 depreciation rates using the depreciation parameters approved in the 2008/2009 GRA to the forecast depreciation parameters for the 2013-2015 GRA.

(c) Please refer to YUB-YECL-83(a) Attachment 1.

(d) There are no net salvage costs included in expense. Please refer to the following for the Net Salvage costs included as part of the Reserve for site restoration (per YEC-YECL-12(b) Attachment 1).

Costs of Removal	49	50	185	100	64
Gross Salvage	(74)	(14)	(68)	(38)	(10)
Schedule 8.6 Line 22	(25)	36	117	62	54

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.33%	2.40%
42300	Reservoirs, Dams & Waterways	3.57%	2.40%
42500	Generators	3.76%	2.68%
42600	Accessory Equipment	3.24%	2.58%
42700	Misc Plant Equipment	3.70%	4.07%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	3.02%	3.50%
44401	Fuel Holders, Producers & Acc. Equipme	2.96%	3.56%
44501	Generating Equipment & Primer Movers ·	3.31%	3.82%
44601	Accessory Electric Equipment - Other	2.98%	2.99%
44701	Misc Power Plant Equipment - Other	3.16%	2.84%
	Carmacks		
44202	Structures and Improvement - Other	2.75%	3.09%
44402	Fuel Holders, Producers & Acc. Equipme	2.98%	3.60%
44502	Generating Equipment & Primer Movers ·	3.30%	3.80%
44602	Accessory Electric Equipment - Other	3.03%	3.03%
44702	Misc Power Plant Equipment - Other	3.21%	2.93%
	Destruction Bay		
44203	Structures and Improvement - Other	2.22%	3.03%
44403	Fuel Holders, Producers & Acc. Equipme	2.97%	5.30%
44503	Generating Equipment & Primer Movers ·	4.09%	7.05%
44603	Accessory Electric Equipment - Other	2.98%	4.77%
44703	Misc Power Plant Equipment - Other	2.97%	4.82%
	Haines Junction		
44204	Structures and Improvement - Other	2.83%	3.21%
44404	Fuel Holders, Producers & Acc. Equipme	3.02%	3.62%
44504	Generating Equipment & Primer Movers ·	3.61%	4.24%
44604	Accessory Electric Equipment - Other	2.80%	2.80%
44704	Misc Power Plant Equipment - Other	2.89%	2.63%
	Old Crow		
44205	Structures and Improvement - Other	2.51%	2.79%
44405	Fuel Holders, Producers & Acc. Equipme	2.99%	3.60%
44505	Generating Equipment & Primer Movers ·	3.74%	4.22%
44605	Accessory Electric Equipment - Other	2.79%	2.79%
44705	Misc Power Plant Equipment - Other	2.88%	2.58%

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.26%	2.57%
44406	Fuel Holders, Producers & Acc. Equipme	2.66%	3.56%
44506	Generating Equipment & Primer Movers ·	3.41%	3.97%
44606	Accessory Electric Equipment - Other	3.07%	3.81%
44706	Misc Power Plant Equipment - Other	3.04%	3.57%
	Ross River		
44207	Structures and Improvement - Other	2.85%	3.25%
44407	Fuel Holders, Producers & Acc. Equipme	2.98%	3.57%
44507	Generating Equipment & Primer Movers ·	3.27%	3.71%
44607	Accessory Electric Equipment - Other	3.01%	3.01%
44707	Misc Power Plant Equipment - Other	3.12%	2.81%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.75%	3.08%
44408	Fuel Holders, Producers & Acc. Equipme	2.99%	3.59%
44508	Generating Equipment & Primer Movers ·	2.69%	3.01%
44608	Accessory Electric Equipment - Other	2.87%	2.87%
44708	Misc Power Plant Equipment - Other	3.24%	2.97%
	Swift River		
44209	Structures and Improvement - Other	2.54%	2.80%
44409	Fuel Holders, Producers & Acc. Equipme	2.94%	3.53%
44509	Generating Equipment & Primer Movers ·	4.04%	4.47%
44609	Accessory Electric Equipment - Other	3.00%	3.01%
44709	Misc Power Plant Equipment - Other	3.10%	2.78%
	Teslin		
44210	Structures and Improvement - Other	2.98%	3.44%
44410	Fuel Holders, Producers & Acc. Equipme	3.01%	3.63%
44510	Generating Equipment & Primer Movers ·	3.39%	3.94%
44610	Accessory Electric Equipment - Other	3.11%	3.14%
44710	Misc Power Plant Equipment - Other	3.18%	2.86%
	Watson Lake		
44211	Structures and Improvement - Other	2.42%	2.66%
44411	Fuel Holders, Producers & Acc. Equipme	3.00%	3.60%
44511	Generating Equipment & Primer Movers ·	3.60%	4.04%
44611	Accessory Electric Equipment - Other	2.81%	2.81%
44711	Misc Power Plant Equipment - Other	3.12%	2.76%
	Mobiles		
44299	Structures and Improvement - Other	3.18%	3.52%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers ·	3.77%	4.23%
44699	Accessory Electric Equipment - Other	3.13%	3.13%
44799	Misc Power Plant Equipment - Other	3.26%	2.86%
Sub Transmission			
45700	Substation Equipment	2.49%	2.25%

The Yukon Electrical Company Limited
Comparison of 2013 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2013 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2013 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Distribution			
47100	Land Rigths	1.51%	1.51%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.59%	2.57%
47500	Underground Conduit	2.41%	3.61%
47510	Underground Services	2.10%	2.87%
47610	Meters	4.10%	7.65%
47630	Automatic Meter Reading	4.52%	7.31%
47710	Substation Equipment	2.77%	2.75%
47810	Street Lights & Signal Systems	3.98%	3.77%
47820	Sentinel Lights	2.99%	2.99%
47910	Line Transformers	3.03%	2.66%
General Plant			
48200	Structures and Improvements	3.10%	2.63%
48300	Office Furniture and Equipment	5.70%	5.70%
48320	Computer Equipment and Accessories	18.73%	18.73%
48400	Transportation Equipment - Category 1	9.34%	6.44%
48500	Tools and Instruments	6.33%	6.33%
48600	Communication Equipment	5.50%	5.50%
48820	Houses	2.66%	2.93%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.54%	2.79%
42300	Reservoirs, Dams & Waterways	3.68%	2.60%
42500	Generators	3.79%	2.77%
42600	Accessory Equipment	3.49%	2.87%
42700	Misc Plant Equipment	4.06%	4.46%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	3.01%	3.52%
44401	Fuel Holders, Producers & Acc. Equipme	2.98%	3.59%
44501	Generating Equipment & Primer Movers -	3.97%	4.22%
44601	Accessory Electric Equipment - Other	3.07%	3.10%
44701	Misc Power Plant Equipment - Other	3.19%	2.92%
	Carmacks		
44202	Structures and Improvement - Other	2.72%	3.06%
44402	Fuel Holders, Producers & Acc. Equipme	2.98%	3.59%
44502	Generating Equipment & Primer Movers -	3.25%	3.72%
44602	Accessory Electric Equipment - Other	3.01%	3.01%
44702	Misc Power Plant Equipment - Other	3.18%	2.90%
	Destruction Bay		
44203	Structures and Improvement - Other	2.44%	4.84%
44403	Fuel Holders, Producers & Acc. Equipme	2.98%	6.70%
44503	Generating Equipment & Primer Movers -	4.00%	7.03%
44603	Accessory Electric Equipment - Other	3.04%	5.87%
44703	Misc Power Plant Equipment - Other	3.03%	5.88%
	Haines Junction		
44204	Structures and Improvement - Other	2.80%	3.17%
44404	Fuel Holders, Producers & Acc. Equipme	3.02%	3.62%
44504	Generating Equipment & Primer Movers -	3.56%	4.17%
44604	Accessory Electric Equipment - Other	2.77%	2.77%
44704	Misc Power Plant Equipment - Other	2.86%	2.61%
	Old Crow		
44205	Structures and Improvement - Other	2.61%	2.94%
44405	Fuel Holders, Producers & Acc. Equipme	2.99%	3.60%
44505	Generating Equipment & Primer Movers -	3.67%	4.17%
44605	Accessory Electric Equipment - Other	2.86%	2.87%
44705	Misc Power Plant Equipment - Other	2.94%	2.66%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.23%	2.54%
44406	Fuel Holders, Producers & Acc. Equipme	2.64%	3.54%
44506	Generating Equipment & Primer Movers -	3.36%	3.91%
44606	Accessory Electric Equipment - Other	3.05%	3.78%
44706	Misc Power Plant Equipment - Other	3.02%	3.55%
	Ross River		
44207	Structures and Improvement - Other	2.80%	3.19%
44407	Fuel Holders, Producers & Acc. Equipme	2.97%	3.56%
44507	Generating Equipment & Primer Movers -	3.24%	3.65%
44607	Accessory Electric Equipment - Other	2.99%	2.99%
44707	Misc Power Plant Equipment - Other	3.10%	2.80%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.73%	3.07%
44408	Fuel Holders, Producers & Acc. Equipme	2.99%	3.59%
44508	Generating Equipment & Primer Movers -	2.64%	2.95%
44608	Accessory Electric Equipment - Other	2.85%	2.85%
44708	Misc Power Plant Equipment - Other	3.21%	2.95%
	Swift River		
44209	Structures and Improvement - Other	2.51%	2.78%
44409	Fuel Holders, Producers & Acc. Equipme	2.93%	3.51%
44509	Generating Equipment & Primer Movers -	4.04%	4.46%
44609	Accessory Electric Equipment - Other	2.98%	2.99%
44709	Misc Power Plant Equipment - Other	3.08%	2.77%
	Teslin		
44210	Structures and Improvement - Other	2.90%	3.36%
44410	Fuel Holders, Producers & Acc. Equipme	3.01%	3.62%
44510	Generating Equipment & Primer Movers -	3.33%	3.86%
44610	Accessory Electric Equipment - Other	3.07%	3.11%
44710	Misc Power Plant Equipment - Other	3.16%	2.85%
	Watson Lake		
44211	Structures and Improvement - Other	2.54%	2.79%
44411	Fuel Holders, Producers & Acc. Equipme	3.01%	3.61%
44511	Generating Equipment & Primer Movers -	4.00%	4.27%
44611	Accessory Electric Equipment - Other	2.87%	2.87%
44711	Misc Power Plant Equipment - Other	3.14%	2.77%
	Mobiles		
44299	Structures and Improvement - Other	3.10%	3.40%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers -	4.36%	4.52%
44699	Accessory Electric Equipment - Other	3.10%	3.10%
44799	Misc Power Plant Equipment - Other	3.23%	2.83%
Sub Transmission			
45700	Substation Equipment	2.48%	2.25%

The Yukon Electrical Company Limited
Comparison of 2014 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2014 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2014 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Distribution			
47100	Land Rigths	1.50%	1.50%
47200	Demand Side Management	10.00%	10.00%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.59%	2.58%
47500	Underground Conduit	2.40%	3.61%
47510	Underground Services	2.10%	2.86%
47610	Meters	4.11%	8.09%
47630	Automatic Meter Reading	4.50%	7.13%
47710	Substation Equipment	2.79%	2.75%
47810	Street Lights & Signal Systems	3.96%	3.75%
47820	Sentinel Lights	2.93%	2.93%
47910	Line Transformers	3.03%	2.65%
General Plant			
48200	Structures and Improvements	3.14%	2.67%
48300	Office Furniture and Equipment	6.67%	6.67%
48320	Computer Equipment and Accessories	20.00%	20.00%
48400	Transportation Equipment - Category 1	9.50%	6.59%
48500	Tools and Instruments	6.67%	6.67%
48600	Communication Equipment	6.67%	6.67%
48820	Houses	2.65%	2.91%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Production Hydro			
42200	Structures	3.61%	2.91%
42300	Reservoirs, Dams & Waterways	3.71%	2.68%
42500	Generators	3.79%	2.82%
42600	Accessory Equipment	3.57%	2.97%
42700	Misc Plant Equipment	4.10%	4.51%
Production Diesel			
	Beaver Creek		
44201	Structures and Improvement - Other	2.94%	3.43%
44401	Fuel Holders, Producers & Acc. Equipme	2.97%	3.58%
44501	Generating Equipment & Primer Movers -	4.09%	4.33%
44601	Accessory Electric Equipment - Other	3.04%	3.07%
44701	Misc Power Plant Equipment - Other	3.17%	2.89%
	Carmacks		
44202	Structures and Improvement - Other	2.69%	3.03%
44402	Fuel Holders, Producers & Acc. Equipme	2.96%	3.58%
44502	Generating Equipment & Primer Movers -	3.19%	3.65%
44602	Accessory Electric Equipment - Other	2.99%	2.99%
44702	Misc Power Plant Equipment - Other	3.16%	2.88%
	Destruction Bay		
44203	Structures and Improvement - Other	2.64%	6.94%
44403	Fuel Holders, Producers & Acc. Equipme	2.99%	8.52%
44503	Generating Equipment & Primer Movers -	4.33%	9.53%
44603	Accessory Electric Equipment - Other	3.10%	7.32%
44703	Misc Power Plant Equipment - Other	3.10%	7.33%
	Haines Junction		
44204	Structures and Improvement - Other	2.76%	3.14%
44404	Fuel Holders, Producers & Acc. Equipme	3.01%	3.62%
44504	Generating Equipment & Primer Movers -	3.51%	4.11%
44604	Accessory Electric Equipment - Other	2.75%	2.75%
44704	Misc Power Plant Equipment - Other	2.84%	2.59%
	Old Crow		
44205	Structures and Improvement - Other	2.90%	3.38%
44405	Fuel Holders, Producers & Acc. Equipme	3.01%	3.65%
44505	Generating Equipment & Primer Movers -	4.06%	4.35%
44605	Accessory Electric Equipment - Other	3.09%	3.15%
44705	Misc Power Plant Equipment - Other	3.13%	2.90%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
	Pelly Crossing		
44206	Structures and Improvement - Other	2.21%	2.51%
44406	Fuel Holders, Producers & Acc. Equipme	2.62%	3.52%
44506	Generating Equipment & Primer Movers -	3.31%	3.84%
44606	Accessory Electric Equipment - Other	3.02%	3.76%
44706	Misc Power Plant Equipment - Other	2.99%	3.53%
	Ross River		
44207	Structures and Improvement - Other	2.78%	3.19%
44407	Fuel Holders, Producers & Acc. Equipme	2.96%	3.56%
44507	Generating Equipment & Primer Movers -	3.27%	3.65%
44607	Accessory Electric Equipment - Other	2.98%	2.99%
44707	Misc Power Plant Equipment - Other	3.10%	2.81%
	Stewart Crossing		
44208	Structures and Improvement - Other	2.84%	3.24%
44408	Fuel Holders, Producers & Acc. Equipme	3.00%	3.61%
44508	Generating Equipment & Primer Movers -	3.13%	3.36%
44608	Accessory Electric Equipment - Other	2.95%	2.98%
44708	Misc Power Plant Equipment - Other	3.22%	2.98%
	Swift River		
44209	Structures and Improvement - Other	2.49%	2.76%
44409	Fuel Holders, Producers & Acc. Equipme	2.92%	3.50%
44509	Generating Equipment & Primer Movers -	3.96%	4.43%
44609	Accessory Electric Equipment - Other	2.95%	2.96%
44709	Misc Power Plant Equipment - Other	3.06%	2.75%
	Teslin		
44210	Structures and Improvement - Other	2.84%	3.29%
44410	Fuel Holders, Producers & Acc. Equipme	3.00%	3.61%
44510	Generating Equipment & Primer Movers -	3.29%	3.78%
44610	Accessory Electric Equipment - Other	3.05%	3.08%
44710	Misc Power Plant Equipment - Other	3.14%	2.83%
	Watson Lake		
44211	Structures and Improvement - Other	2.65%	2.91%
44411	Fuel Holders, Producers & Acc. Equipme	3.01%	3.61%
44511	Generating Equipment & Primer Movers -	3.93%	4.26%
44611	Accessory Electric Equipment - Other	2.95%	2.95%
44711	Misc Power Plant Equipment - Other	3.16%	2.78%
	Mobiles		
44299	Structures and Improvement - Other	3.02%	3.32%
44499	Fuel Holders, Producers & Acc. Equipme	0.00%	0.00%
44599	Generating Equipment & Primer Movers -	4.22%	4.50%
44699	Accessory Electric Equipment - Other	3.08%	3.08%
44799	Misc Power Plant Equipment - Other	3.20%	2.81%

The Yukon Electrical Company Limited
Comparison of 2015 Depreciation Rates - 2008/2009 Approved Parameters vs Updated Parameters

Account	Description	2015 Depreciation Rates Based on 2008/2009 GTA Composite Rate	2015 Depreciation Rates Based on 2013/2015 GTA Composite Rate
Sub Transmission			
45700	Substation Equipment	2.47%	2.24%
Distribution			
47100	Land Rigths	1.50%	1.50%
47200	Demand Side Management	10.00%	10.00%
47300	Poles & Fixtures	2.67%	4.20%
47400	Overhead Conductor	2.67%	4.16%
47410	Overhead Services	2.60%	2.58%
47500	Underground Conduit	2.40%	3.61%
47510	Underground Services	2.10%	2.86%
47610	Meters	4.10%	7.40%
47630	Automatic Meter Reading	4.54%	8.08%
47710	Substation Equipment	2.80%	2.75%
47810	Street Lights & Signal Systems	3.97%	3.76%
47820	Sentinel Lights	2.87%	2.87%
47910	Line Transformers	3.03%	2.65%
General Plant			
48200	Structures and Improvements	3.13%	2.66%
48300	Office Furniture and Equipment	6.67%	6.67%
48320	Computer Equipment and Accessories	20.00%	20.00%
48400	Transportation Equipment - Category 1	9.87%	6.98%
48500	Tools and Instruments	6.67%	6.67%
48600	Communication Equipment	6.67%	6.67%
48820	Houses	2.63%	2.89%

YEC-YECL-12

Reference: Section 7 – Depreciation – Depreciation Study

Request:

(a) The YUB ruled in decision 2009-02 that YECL was not entitled to collect a provision for salvage. Please explain what has changed in Yukon that justifies YECL requesting this large increase in depreciation expense.

(b) Please provide a continuity schedule of the reserve for site restoration for each year 2008-2012. For each year, please provide a schedule of individual charges to the Fund and, for each charge, provide the justification for each charge to the fund.

(c) Please provide further detailed explanation regarding how the proposed deferral account to allow the ability to file future applications, as necessary, to change its depreciation parameters within the 2013-2015 test period, and flow through the impact of any such change to customers within the test period would operate. Please provide any illustrative examples.

(d) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) The first issue that has changed since Board Order 2009-02 is that sending the right price signal to customers has taken on added importance as a result of diesel generation once again being on the margin in the Yukon. As Yukon Energy is aware, price signals that reflect the full cost to serve customers were discussed as part of the 2010 Yukon Electrical and Yukon Energy Joint Phase II Rate Application. While a large amount of the rate design discussion centered on economy and efficiency principles within the rate design of runoff rates and what exactly was meant by the term “economy and efficiency”, Yukon Electrical notes the following statements in Board Order 2010-13 (paragraphs 196-197):

> The Board has considered the views of all the Parties and notes that there clearly is no consensus on this issue. However, it is clear that the Companies agree that in the past, economy and efficiency has been linked to the incremental cost of diesel generation.
>
> In terms of pricing signals, the Board is of the view that the best pricing signals to customers are those prices that reflect the full cost to serve those customers. Arguments on incremental cost of diesel generation, or what portion of the incremental cost of diesel generation should be reflected in the runoff rates should take a distant backseat to the proper alignment of costs to revenues for each rate class. Once rebalancing has occurred for the rate classes, then issues relating to runoff can be examined in greater detail.

While the above statements were in the context of runoff rates, it is for this exact reason of prices reflecting the full cost to serve customer that Yukon Electrical is requesting to once again collect negative net salvage as part of its revenue requirement.

A second large change since Board Order 2009-02 has been the development and inclusion in this Application of the Joint Yukon Electrical and Yukon Energy Demand Side Management (DSM) program. As Yukon Energy is aware, this program will promote energy conservation and will result in lower energy consumption. It is Yukon Electrical's position that it is counter intuitive to be investing in this DSM program while, at the same time, not sending the right price signal by not fully charging current customers for the cost to provide electric service; namely the cost associated with net salvage.

A third large change since Board Order 2009-02 has been the cessation of collection of net salvage resulting in Yukon Electrical falling considerably behind in its required recovery of the funds for future removal of assets. In the 3 year period from 2009 through 2011, an increase in the amount of Future Removal and Site Restoration (i.e. FRSR) deficiency transfer from current users of the Yukon Electrical utility assets to future rate-payers of $7.9 million has accrued to a total balance of over $12 million. It is noted that this significant increase in transfer to future rate-payers is caused by two significant forces. Firstly, the retirement costs associated with assets that have retired over the past 3 year

period have drawn down the FRSR by over 6.2%[1] of the balance that existed at December 31, 2008. However, this draw down of the FRSR was caused by retirements of only approximately 3% of the plant in service as at December 2008[2]. In other words, the FRSR balance is drawing down at approximately twice the rate of the asset retirement activity of the plant in service balance that existed at December 31, 2008.

The second cause of the significant increase in the accumulated FRSR deficiency is the fact that older vintages of assets are now 3 years closer to expected retirement, providing less time for these vintages to recover the FRSR deficiency. While approximately 3% of the investment in plant in service as of 2008 has retired over the period from 2009 through 2011, this pace of retirements is expected to significantly increase in future years, which will require significantly increased amounts of cost of removal funding. For example, over the past 16 years, 4 diesel generating units have been removed and retired from service. However, over the next 3 year period 7 units will require replacement due to age and condition. As such, the pace of retirements will significantly increase over the next few years.

Gannett Fleming has advised that the level of accumulated FRSR deficiency will continue to increase at an increasingly rapid pace in future years, if FRSR funding is not re-instated into the deprecation calculations. As noted above there are two independent forces that are causing increases in the amount of the deficiency, that will cause the deficiency to grow at an exponential rate, as witnessed over the past 3 year period. The inter-generational inequity of the current process as mandated by the Board in Decision 2009-02 has already caused future rate-payers to bear $7.9 million of additional burden, and continuation of this practice will see this burden increase by exponential amounts in future years.

The concept of inclusion of net salvage provisions into the depreciation rate calculations has been a topic of debate in many regulatory jurisdictions across Canada since the issuance of the YUB Board Decision 2009-02. As indicated in the Additional Evidence of Larry Edwin Kennedy filed with the current Yukon Electrical Application, this topic has received considerable attention in the

[1] Calculated by comparing the 2008 FRSR balance of $4,688,112 to the 2012 balance of $4.395,151
[2] Based on2009 through 2012 retirement transactions of $3.3 million compared to the 2008 plant in service balance of $115.7 million

depreciation rate filings in many jurisdictions. However, notwithstanding the significant amount of regulatory debate, the inclusion of net salvage percentages in the depreciation rate calculations continues to be widely accepted throughout Canada and North America. Furthermore, the topic of re-instatement of net salvage into depreciation rate calculations has been specifically discussed in hearings in British Columbia in 2011, in which the BCUC specifically allowed FortisBC Energy Inc. to re-instate collection of net salvage as part of their depreciation rate calculations. As stated by the BCUC in FortisBC Energy's 2012-2013 Revenue Requirements and Rates Decision, dated April 12, 2012, pages 83-84:

> The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.
>
> While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.

(b) Please refer to YEC-YECL-12(b) Attachment 1. The charges to the reserve are related to capital projects for replacement of assets.

(c) Please refer to YEC-YECL-12(c) Attachment 1 for an illustrative example of how the proposed deferral would operate.

(d) Yukon Electrical is not aware of any other similar deferral accounts currently approved / used by other regulated utilities in Canada.

The Yukon Electrical Company Limited
Continuity Schedule of Reserve for Site Restoration

	YEAR					
	2008	2009	2010	2011	2012	
Beginning Balance	(4,688)	(5,379)	(4,677)	(4,559)	(4,497)	
Total Depreciation Expense	(535)	(103)	-	-	-	
Amortization of Differences	(131)	769	-	-	-	
Costs of Removal	49	50	185	100	64	Note 1
Gross Salvage	(74)	(14)	(68)	(38)	(10)	
Ending Balance	(5,379)	(4,677)	(4,559)	(4,497)	(4,443)	

Note 1 - Cost of Removal Detail

		YEAR				
		2008	2009	2010	2011	2012
Group Account	Group Account Description					
44200	Int Combust Structures	-	-	5	-	-
	Int Combust Generators	-	-	-	2	-
47300	Poles and Fixtures	12	22	110	57	35
47400	Overhead Conductor	19	8	8	11	1
47500	Underground Conduit	5	6	8	1	3
47610	Meters	-	-	5	2	7
47710	Distribution Substation	10	9	4	-	-
47810	Street Lights	-	2	13	17	0
47910	Transformers	3	4	32	9	18
	Total	49	50	185	100	64

The Yukon Electrical Company Limited
Illustrative Example of Proposed Depreciation Deferral

For account 47300, the Average Service Life determined by the depreciation study is 45 years. New information becomes available to Yukon Electrical that causes the company to believe that this assumption may no longer be accurate, and that the actual Average Service Life is now only 39 years. As a result, the change in life depreciation expense is as follows:

Based on depreciation parameters determined by the current depreciation study:

Account	Description	Life Parameter	Forecast Cost	Life Expense	Life Rate
47300	Poles & Fixtures	R3-45	36,821,587	883,748	2.40%

Based on updated parameters:

Account	Description	Life Parameter	Forecast Cost	Life Expense	Life Rate
47300	Poles & Fixtures	R3-40	36,821,587	1,006,220	2.73%

As a result, Yukon Electrical would have to record an additional $122,472 of depreciation expense in its financial statements for 2014.

Pre-Tax Impact of Change in Depreciation Expense	174,960
Pre-Tax Impact of Change in Rate Base	(5,505)
Additional Amount to Be Collected From (Refunded to) Customers	169,454

YEC-YECL-13

Reference: Section 8 – Return on Rate Base – Cost of Capital

Request:

(a) Please provide a copy of BCUC Order G-75-13.

(b) Please provide details and discuss YECL's proposal of using Automatic Adjustment Mechanism (AAM) and ROE Deferral Account, including:

(i) if YECL proposing that the AAM method for YECL will be the same as for the utilities in British Columbia affected by British Columbia Utilities Commission (BCUC) Order G-75-13 and any future changes to BCUC Order G-75-13 will affect YECL ROE;

(ii) how and when (beginning of the year, when Canada Bond yield changes or other) YECL is proposing to calculate AAM;

(iii) what would be basis for calculating of difference in ROE, including Rate Base (timing and amount, i.e. YUB approved Rate Base for test year or actual Rate Base at the time of adjustment), common equity ratio (timing and ratio);

(iv) by providing examples and impacts to the test years by assuming 10% higher and 10% lower long-term Canada Bond yield compared to the yield rate used for calculation of 9.21% ROE.

(c) Please confirm that per paragraph 3 of British Columbia Utilities Commission Order G-75-13 "[t]he implementation of the model [AAM] will be subject to conditions outlined in the Decision."

(d) Please provide details of the conditions outlined in the BCUC Order G-75-13 as per c) above.

(e) Please confirm that the proposed AAM and ROE deferral account does not go beyond 2013-2015 test years. If not confirmed please explain why?

(f) Please confirm that such a deferral account reduces YECL's regulatory risk and transfers this to the ratepayer. If so, why is it necessary to do so? If not, why not.

(g) Please provide examples of other similar deferral accounts used by other regulated utilities in Canada.

Response:

(a) Please refer to YEC-YECL-13(a) Attachment 1.

(b) (i) Yukon Electrical is proposing to adjust its 2014 and 2015 ROE in accordance with any adjustments that may be made to the ROE of the benchmark utility in British Columbia as a result of the application of the AAM formula, as calculated and determined by the BCUC.

(ii) It will be the BCUC that calculates the quantum of the AAM. The precise timing and mechanics of the AAM formula and its application are currently being determined by the BCUC, but Yukon Electrical understands the intent is for the AAM formula to be applied annually in advance of any given test year.

(iii) Should there be a change in the 2014 or 2015 BCUC GCOC ROE benchmark as a result of the AAM, Yukon Electrical proposes to base the adjustment on the YUB approved rate base and common equity ratio for each of those years.

(iv) Please refer to WL-YECL-16(b) for an illustration of the impact to ROE and Yukon Electrical's revenue requirement as a result of potential changes in the Long Canada Bond Forecast.

(c) Confirmed.

(d) As per pages 91 and 92 of the May 10, 2013 BCUC GCOC Decision:

> "To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded.

> Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent."
>
> "FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015."

(e) Confirmed.

(f) Not confirmed. The BCUC is re-instituting an AAM as it has the potential to contribute to regulatory efficiency by avoiding frequent costly and time consuming ROE proceedings, and did not note in its decision any impact the AAM formula has on the risk profile of the benchmark utility.

(g) Yukon Electrical has not conducted an exhaustive search of similar mechanisms used in other regulatory jurisdictions. In British Columbia, the AAM will be used by: FortisBC Inc., FortisBC Energy (Vancouver Island), FortisBC Energy (Whistler), Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.

In accordance with prior Yukon Board direction, Yukon Electrical is proposing to link its ROE to the recently approved BCUC GCOC benchmark rate plus a risk premium, and, consistent with the BCUC Decision, to include a mechanism for adjusting its ROE in step with any changes to the ROE of the BCUC benchmark utility resulting from the application of the AAM formula.

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING
(STAGE 1)

DECISION

May 10, 2013

Before:

D.A. Cote, Commissioner/Panel Chair
R. Giammarino, Commissioner
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner

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EXECUTIVE SUMMARY

By Order G-20-12 on February 28, 2012, the British Columbia Utilities Commission (Commission) initiated the Generic Cost of Capital (GCOC) proceeding pursuant to section 82 of the *Utilities Commission Act* to review and determine among other things, the following:

- The setting of the appropriate cost of capital for a benchmark low-risk utility;
- The possible return to an automatic adjustment mechanism (AAM) for setting the return on equity (ROE) for the benchmark utility each year; and
- The establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt.

By Order G-48-12 on October 11, 2012, the Commission established the following:

- The proceeding will have two stages; Stage 1 will determine the cost of capital for the benchmark utility and Stage 2 will establish the cost of capital for other utilities as compared to the benchmark.
- Fortis Energy Inc. (FEI) in its pre-amalgamation state will serve as the benchmark utility for the GCOC proceeding; and
- An oral public hearing commencing on December 12, 2012, will be held to determine the cost of capital for the benchmark utility.

Fair Return Standard

The Fair Return Standard is foundational for cost of capital proceedings and has three requirements for a fair and reasonable return on capital: the comparable investment requirement, the financial integrity requirement, and the capital attraction requirement. The Commission Panel, consistent with previous decisions and the regulatory compact, confirms that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. In the current proceeding, the Commission Panel has not considered the rate impacts of the revenue required to yield the fair return but has noted that by seeking an optimal capital structure and the opportunity cost of capital, the needs of customers are being served.

Contextual Issues

Three important issues were raised that were contextual in nature; the significance of past cost of capital decisions, the significance of decisions from other jurisdictions and the relevance of the disparity between "allowed" and "actual" ROE.

With respect to past cost of capital decisions and appropriate points of reference, the Commission Panel accepts that the 2009 Decision is a reasonable point of reference with respect to long-term risk as this is the most recent proceeding and has been used extensively by the parties. The Panel also remains open to looking back to the 2006 ROE Decision where appropriate.

With respect to reliance upon data from US jurisdictions, the Commission Panel has determined that it is appropriate to continue to accept the use of historical and forecast data but do not accept that US data should be considered to be the same or be given equal weight as data for Canadian utilities. Concerning Canadian jurisdictional decisions, the Panel acknowledges the importance of considering methodologies, approaches, and regulatory principles related to other jurisdictions' decisions but does not accept the use of results and values for the purpose of calibration.

Concerning the relevance of disparity between FEI's "allowed" and "actual" ROE, the Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from FEI's positive track record. However, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach. Additionally, the Panel is of the view that these differences are assessed in revenue requirement proceedings.

Capital Structure

In determining an appropriate capital structure for the benchmark utility, the Commission Panel considered FEI's long and short-term risk, development of an optimal capital structure, credit ratings and metrics and experiences of other jurisdictions.

The Commission Panel is supportive of maintaining an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.

Return on Equity

The Commission Panel considered expert evidence on various model approaches to determine ROE. The Panel finds that the discounted cash flow model and the capital asset pricing model should be given equal weight in determining the ROE of the benchmark utility. No weight was given to the equity risk premium and comparative earnings models. The Commission has determined that an ROE of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the benchmark utility. The benchmark utility ROE will be effective January 1, 2013 and will be effective until December 31, 2015, subject to updating as a result applying the AAM formula.

Automatic Adjustment Formula

Consideration was given to re-instituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings, which had been eliminated in the 2009 Decision. In addition, consideration was given to the status of AAMs in other jurisdictions and what optional AAMs might be considered. The Commission Panel has determined that it is appropriate to re-establish an AAM formula noting that it better meets the FRS than giving no consideration to the market changes over the period between ROE proceedings. The Panel has directed that a two variable model considering changes to utility bond spreads and the long-term Canada bond yield be

established to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

Cost of Capital – Small Utilities

Stage 1 of the GCOC proceeding considered the cost of capital for the benchmark utility, FEI. Stage 2 will assess the differences in short and long-term risk faced by regulated utilities in British Columbia other than FEI and their impact on the capital structure and ROE for these utilities. The Commission Panel has recommended that the utilities be separated into three groups, each of which will be handled separately. The Commission Panel has also made a number of determinations and findings with respect to the handling of the size factor as a business risk and deemed short and long-term debt interest rates.

1.0 INTRODUCTION

1.1 Background

The 2009 ROE Decision[1] (2009 Decision) was issued concurrently with Order G-158-09 on December 16, 2009. The Order set the return on equity for FEI, the benchmark utility in British Columbia, at 9.5 percent effective July 1, 2009, and the equity ratio at 40 percent effective January 1, 2010. Order G-158-09 also eliminated the AAM, which had been utilized to set the ROE for the benchmark utility annually. Since that Order, there have been no further adjustments to the ROE or capital structure of the benchmark utility.

This Decision for Stage 1 of the Generic Cost of Capital (GCOC) proceeding sets out:

- the new approved ROE and capital structure for FEI;
- the new automatic adjustment formula and the conditions under which it will be in effect; and
- the framework to review the cost of capital for small utilities.

Stating that changes have occurred in the financial markets since the 2009 Decision, the Commission, by Order G-20-12 dated February 28, 2012, initiated the GCOC proceeding pursuant to section 82 of the *Utilities Commission Act* (*UCA*) to review and determine, among other things, the following:

- the ROE and capital structure for a benchmark low-risk utility;
- the possible return to an AAM to set the ROE for the benchmark utility each year; and
- a deemed capital structure and deemed ROE for small utilities, particularly those utilities without short-term debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. The Order further divided the list of utilities regulated by the BCUC into Affected Utilities and Other Utilities. The Affected Utilities have been so designated given their active participation in previous ROE proceedings or their anticipated interest

[1] In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and capital Structure Decision, December 16, 2009.

in the GCOC proceeding as investor-owned utilities. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. The Other Utilities are so designated as they have not actively participated in previous ROE proceedings and they were not expected to file evidence in the GCOC proceeding.

On April 18, 2012, the Commission, by Order G-47-12, issued a final scoping document, which set out the purpose and scope of the proceeding. On April 19, 2012, the Commission issued a preliminary draft of the minimum filing requirements. Following submissions by Registered Interveners, the Commission issued Order G-72-12 on June 1, 2012, which set out the minimum filing requirements for those utilities expected to participate and a preliminary regulatory timetable. In an attachment to Appendix A to the Order, the Commission also placed on the record the terms of reference for a Survey of Cost of Capital Practices in Canada prepared by the Commission consultant, the Brattle Group (Brattle Report).

On October 11, 2012, following a procedural conference held on October 4, 2012, the Commission by Order G-148-12 established that in 2012, FEI in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding. The Order also established an oral public hearing to commence on December 12, 2012, to hear the cost of capital for the benchmark utility. In addition, it was determined that the proceeding will have two stages: Stage 1 establishing the ROE and capital structure for FEI the benchmark utility, and Stage 2, establishing a cost of capital for other utilities as compared to the benchmark utility.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

The Commission determined the purpose and scope of the GCOC proceeding in Order G-47-12, with certain outstanding matters such as the appropriate utility, which would serve as the benchmark utility, determined by Order G-148-12 dated October 11, 2012. The purpose and scope of this proceeding are as follows:

PURPOSE OF THE PROCEEDING

The main purposes of the GCOC Proceeding are:

I. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;

II. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and

III. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

SCOPE OF THE PROCEEDING

I. The appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity, and interest on debt.

II. Establishment of a Benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year.

III. Whether re-establishment of an ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is accepted as a result of the GCOC Proceeding, it would be implemented January 1, 2014. If not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013 on a regular basis.

IV. A generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility.

V. In certain circumstances, a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate.

VI. In certain circumstances for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM). If warranted, the Interest AAM would be implemented for January 1, 2014. If not warranted, setting a future regulatory process on how the deemed interest for a benchmark low-risk utility would be adjusted in future years beyond December 31, 2013.

1.3 Regulatory Process

As noted previously, the Commission retained The Brattle Group to prepare a survey report on the Cost of Capital Practices in Canada. The Brattle Report, filed as Exhibit A2-3 on June 8, 2012, provides a description of the cost of capital estimation methods and the common approaches in implementing the results in Canadian jurisdictions. The Brattle Report was intended to provide context and background for the establishment of the cost of capital of a low-risk benchmark utility

in B.C. All parties were provided with the opportunity to file Information Requests (IRs) on the Report.

In accordance with Order G-72-12, the following utilities filed minimum filing requirements:

- FEI, FortisBC Inc. , FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC (Whistler) Inc. (FEW),[collectively (FBCU)];
- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. [collectively (PNG)]; and
- Corix Utilities (Corix).

The Industrial Customers Group of FortisBC Inc. (ICG) and the BC Utility Customers comprising the Association of Major Power Customers of BC (AMPC), the British Columbia Pensioners' and Seniors' Organization (BCPSO), and the Commercial Energy Consumers of BC (CEC) were active in the proceeding. Two rounds of IRs with respect to evidence filed by Affected Utilities and one round of IRs on evidence filed by Interveners took place.

The oral public hearing, including an *in camera* session on FBCU's confidential reports, took place over a period of seven days between December 12, 2012 and December 21, 2012. FBCU tendered five witness panels for cross-examination and Corix, BC Utility Customers, and the ICG each had one witness panel for cross-examination.

A list of procedural orders in the GCOC proceeding is included in Appendix A. A list of Appearances is included in Appendix B and Appendix C contains a list of witness panels that gave evidence. Appendix D contains the List of Exhibits. Appendix E contains a risk matrix used in a recent Commission decision with respect to a small utility that is Appendix B to Order C-1-13, Appendix F contains summary tables of ROE estimates by expert witnesses retained by the utilities and ratepayer groups, and. Appendix G is a list of acronyms.

1.4 Approach to Decision

The legal framework for determining a fair return for a regulated utility is called the "Fair Return Standard" and is discussed in Section 2.

There are a number of broader issues of importance, which were raised by this proceeding. These are contextual in nature and include the following:

- importance of past cost of capital decisions;
- consideration of decisions from other jurisdictions; and
- the relevance of the disparity between "allowed" and "actual" ROE.

These issues are discussed in Section 3 and provide the Commission Panel with a context to assist in reviewing and assessing the evidence.

Section 4 deals with an appropriate capital structure given FEI's level of risk with consideration of credit ratings and metrics and decisions in other jurisdictions. Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses. Section 6 examines potential AAM models and whether there is justification to return to a reliance on such a mechanism. Section 7 considers issues related to cost of capital for small utilities, and Section 8 examines the need for financial models presented in proceedings such as this to have a sound theoretical basis.

2.0 LEGISLATIVE FRAMEWORK – THE FAIR RETURN STANDARD

2.1 Legislative Requirement

The enabling legislation for the BCUC, the *UCA*, provides that a public utility must not make, demand or receive:

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia;

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

A rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or

(c) unjust and unreasonable for any other reason.[2]

The *UCA*, and other Canadian legislation delegating power to regulatory tribunals, follow what is known as the "Regulatory Compact." In general terms, the Regulatory Compact states that in exchange for an exclusive franchise to serve a defined area:

- a regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at cost-based rates as prescribed by the regulatory tribunal, and
- the regulatory tribunal must allow the regulated utility an opportunity to earn a fair return on its invested capital.

(Exhibit C4-9, p. 7; BCPSO Final Submission, p. 3)

The approach to determining a fair return on the cost of invested capital in a regulated utility has normally been referred to as the Fair Return Standard (FRS).

---

[2] *UCA* sections 59 (1) (a) (b), 59(5), 60 (1) (a) (b) (i)

2.2 Elements of a Fair Return Standard

The Supreme Court of Canada decision in *Northwestern Utilities Ltd*. v. *Edmonton (City),* [1929] S.C.R. 186, (*Northwestern Utilities*) at pages 192-193 describes the FRS as follows:

> "The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (per Lamont J.)

The Brattle Report notes that the legal decisions, which provide the overarching principles of the FRS, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. In other words, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (Exhibit A2-3, pp. 2-3)

On page 8 in the 2009 Decision, the Commission endorsed the National Energy Board's (NEB) articulation of the Fair Return Standard in NEB Decision RH-1-2008 where NEB stated:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - Be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - Enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

Ms. McShane, the expert witness for FBCU, submitted that the standards for a fair return arise from legal precedents and there are three requirements the utility must:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and
3. Attract capital on reasonable terms.

According to Ms. McShane, the legal precedents make it clear that the three requirements are separate and distinct. The FRS is met only if all three requirements are satisfied. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8)

Dr. Laurence Booth, the expert witness for the BC Utility Customers, submitted that the definition of a fair rate of return was confirmed in *BC Electric* [*Railway Co. Ltd. v. Public Utilities Commission of B.C. et al ([1960] S.C.R. 837)*] when Mr. Justice Lamont adopted the definition of a fair rate of return, put forward in *Northwestern Utilities*.

Dr. Booth submitted that the definition in the *Northwestern Utilities* is referred to as an opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. Dr. Booth further submitted that to any modern financial economist, Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a risk adjusted discount rate or expected rate of return. (Exhibit C6-12, pp. 7, 8)

2.3 Application of the Fair Return Standard

The Commission Panel observes that the application of the FRS leaves room for disagreement, judgment and discretion. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure. (Exhibit A2-3, p. 2)

The Panel also notes the words of the Alberta Utilities Commission (AUC) on this subject related to conflicting evidence and applying judgment:

> "....the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the TransCanada Pipelines decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors."[3]

The Commission Panel further notes the words of the Federal Court of Appeal's ruling in *TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149* on just and reasonable tolls. It quotes the *Northwestern Utilities* and states:

> "Tolls which reflect a fair return on capital will be just and reasonable to both the Mainline and its users.

It further states:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the point of view of the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring Mainline's costs are not overstated .... And, specific to this appeal, customers and consumers have an interest in ensuring that the Mainline's cost of equity is not overstated."
>
> (TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149, para. 33, 34)

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[3] AUC 2009 Generic Cost of Capital Decision, November 12, 2009, p. 28

Submissions by Parties

None of the parties disagree with the Fair Return Standard as the applicable test. The Utilities and Interveners, however, disagree on how this test should be applied.

FBCU take the position that the overall rate of return allowed for FEI must be based on the utility's true cost of capital without compromising the legitimate cost of service to achieve lower rates in the short-run. FBCU submit that the combination of allowed ROE and capital structure should permit FEI to maintain credit ratings that are at a minimum in the "A" credit category in varying market conditions. This matter is further addressed in Section 4.5.

FBCU argue that a fair return is not synonymous with the lowest possible return. It pointed out that in the 2006 ROE Decision (2006 Decision),[4] the Commission had articulated that the "lowest possible" was not the appropriate test. Therefore, FBCU submit that the Commission should not rely on evidence on rate impacts and that the view of Dr. Safir, ICG's expert witness, that the outcome of a "fair return" should always favour the lower range is fundamentally inconsistent with the authorities on the FRS. (FBCU Final Submission, pp. 1, 7, 11-12)

The AMPC/CEC do not dispute the definition of the FRS based on the NEB Decision RH-1-2008 and endorsed by the Commission in the 2009 Decision. However, the AMPC/CEC disagree with FBCU's submission that the three requirements listed are the only factors to be considered when deciding what constitutes a fair return, with no consideration of the Commission's broader mandate to balance the interest of customers and regulated utilities. AMPC/CEC submit that when acting as the surrogate for competition, the Commission cannot and must not protect FEI from all business and financial risk by unnecessarily raising the ROE and common equity at the expense of customers; and the Commission must scrutinize whether the cushion FEI asks for is truly necessary to meet the FRS in light of its broader mandate to protect consumers. In Section 4.5 of this Decision, the Commission Panel discusses the application of the FRS and the role of credit metrics in the implementation of the FRS requirements.

[4] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision and Order G-14-06, March 2, 2006.

According to AMPC/CEC, Dr. Booth's evidence shows that he recommended a fair return by applying the principle in the FRS that "only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair." In addition, AMPC/CEC state that among other things, Dr. Booth checked his findings against numerous independent, reputable sources which confirmed that his estimates were reasonable. (AMPC/CEC Final Submission, pp. 5-7)

The BCPSO agrees with FBCU's characterization of the FRS and agrees that utilities are entitled to a competitive return as defined in the FRS' three tests regardless of the rate impact. However, BCPSO submits that it is not the same as to say that customer interests carry no weight in setting an appropriate deemed cost of capital as utility customers have an interest in ensuring that the utility's cost of capital is not overstated. BCPSO submit that a fair return is one that takes into account the right of utility customers to pay no more than a fair and reasonable charge for the service provided. Based on its logic, BCPSO submits that the evidence from Exhibit B1-42 which compares the rate impact of a 5 percent change in the equity ratio to a 50 and 100 basis point change in ROE is admissible; and furthermore, if the utility can be provided a competitive return with less rate impact, that option should be chosen. (BCPSO Final Submission, pp. 3-5)

ICG submits that the interests of customers should be paramount to those of the shareholders and reiterates Dr. Safir's testimony that where a range of competitive returns is available for evaluation, the outcome of a "fair return" should always favour the lower range presented. (ICG Final Submission, p. 3)

In Reply, FBCU submit that the Commission would err in accepting ICG's argument that regulation is simply to benefit customers. FBCU submitted that the Commission, in the 2009 Decision, had been explicit that it was not accounting for rate impacts in reaching its decision. (FBCU Reply, pp. 2-3)

Commission Determination

In previous decisions, the Commission concluded that the opportunity to earn a fair return must be provided to each regulated utility as a separate obligation from those service and financing requirements detailed in other sections of the *UCA*. For instance, on page 8 of its 2006 ROE Decision, the Commission said:

> "In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."

The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility. This Decision reiterates the principle articulated in the 2006 ROE Decision and the 2009 Decision, and argued by FBCU on pages 7 to 9 in its Final Submission, that the Commission does not consider the rate impacts of the revenue required to yield the fair return. However, by seeking an optimal capital structure and the opportunity cost of capital we are serving the needs of the customer.

While this Commission Panel has not considered the rate impacts of the revenue required to yield the fair return *per se*, we are of the view that the capital structure of the utility should be set efficiently and, therefore, there is value in finding an optimal capital structure. Exhibit B1-42 provides comparative information on revenue requirements for FEI based on either a change in equity thickness or a change in ROE. The ICG submits that the Commission should reduce the ROE before reducing the capital structure of FEI. (ICG Final Submission, p. 4) In this regard, the Commission Panel finds the information on rate impacts as presented in Exhibit B1-42 useful. An optimal capital structure is discussed further in Section 4.4.

3.0 CONTEXTUAL ISSUES

This section considers important issues raised by this proceeding that are contextual in nature; they include:

- The significance of past cost of capital decisions;
- The relevance of US data and the significance of decisions from other jurisdictions; and
- The relevance of the disparity between "allowed" and "actual" ROE.

3.1 Past Cost of Capital Decisions

An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel's decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time. Each of these referenced areas will be discussed in turn.

Submissions by Parties

3.1.1 Changes in Capital Markets

Throughout this proceeding, the FBCU have relied upon and underlined the Commission's statement that changes have occurred in capital markets since the 2009 Decision was issued. They have taken the position that capital markets are similar (albeit for different reasons) to what they were in the fall of 2009 when the previous cost of capital proceeding took place. The FBCU have relied very heavily on the 2009 Decision as a reference point for the current proceeding and have provided comparisons between what they believe exists today as opposed to conditions which existed at the time of the 2009 Decision. FBCU have relied upon the opinion evidence prepared by two of their expert witnesses, Ms. McShane and Mr. Engen, which showed that many of the key indicators of conditions within capital markets are similar and in some cases worse than the same indicators reflecting capital markets late in 2009. FBCU maintain that the experts along with market indicators

and Bank of Canada published information all suggest that equity capital markets in Canada are challenging and volatile and the market cost of equity has risen since 2009. In summary, FBCU maintain that current market conditions provide no basis for reducing FEI's overall return as argued by interveners. (FBCU Final Submission, pp. 1-2, 16-30)

ICG takes issue with FBCU on their choice of 2009 as an appropriate reference point and argue that a more appropriate reference point was the 2006 Decision. ICG submits that the 2009 Decision did not appropriately balance the interests of customers and shareholders and gave inappropriate weight to the interests of shareholders. Moreover, ICG submits that the 2009 Decision represented a significant departure from previous Commission cost of capital decisions. With respect to its Canadian peers, ICG points out that the weighted equity return component was materially lower (by 0.47) in 2005 through 2009 and materially higher (by 0.57) in the 2010 to 2012 period. ICG argues that the 2009 Decision should not be a point of reference for this decision given a steady decline in FEI's business risks since 2005. (ICG Final Submission, pp. 11-12)

BCPSO also takes issue with the use of the 2009 Decision as a reference point for this decision, expressing concern as to whether the capital market conditions comparator dates are consistent across the two proceedings. BCPSO submits that the current proceeding is forward looking with respect to capital conditions and snapshot-style evidence of past capital conditions is of limited value. In its view, the economic tests such as equity risk premium (ERP), comparable earnings (CE) and discounted cash flow (DCF) provide a better basis in assessing cost of capital stating that they "are more precise, forward looking, and can be made industry or company specific." The primary value of evidence relating to general market conditions lies in the trends it demonstrates. (BCPSO Final Submission, p. 6)

AMPC/CEC submit that regulators do not base a cost of capital decision on immediate circumstances only. They assert that the Commission will consider economic and financial conditions occurring since the last hearing and will also consider the outlook on a going forward basis. Referring to Mr. Engen's S&P/TSX Composite Index 10 Year Performance data, AMPC/CEC state that the difference now "is that the last few years have witnessed the market hold or increase ground it recovered, whereas in the lead up to the 2009 hearing, it had just suffered a dramatic crash." They further point out the FBCU argument that capital markets are similar to what they were in 2009 is in conflict

with their own witnesses' (Ms. McShane and Dr. Vander Weide) DCF calculations, which have declined considerably since the close of evidence in the last hearing. (AMPC/CEC Final Submission, pp. 28-29; Exhibit B-1-9-6, FBCU Evidence, p. 14, updated in Exhibit B-1-49)

In Reply to ICG, the FBCU state that the choice of 2009 as a point of comparison is because that proceeding is where the Commission most recently assessed FEI's business risk. To disregard this in favour of the 2006 Decision because ICG preferred the outcome in FBCU's view is indefensible. (FBCU Reply, p. 21)

Concerning the AMPC/CEC's submissions regarding the inconsistency in capital markets being similar to 2009 and FBCU's witnesses' DCF calculations, the FBCU state the following:

- Mr. Engen's evidence relates to the overall capital market and trends in the market cost of equity which indicate the market cost of equity is higher today.
- Ms. McShane's and Dr. Vander Weide's DCF calculations relate to a narrow segment of the overall market and deal specifically with FEI's cost of equity. (FBCU Reply, p. 5)

3.1.2 Changes in Long-Term Risk

While there has been considerable disagreement with respect to relying upon 2009 capital markets as a reference point for comparison, there has been little concern raised by the parties with respect to using the 2009 Decision as a reference for changes in long-term risk. Both the FBCU and interveners have relied heavily on what has changed since 2009 and in some cases referred back to the period prior to the 2006 Decision as a source of comparison.

Commission Discussion

The Commission Panel accepts that many of the indicators reflecting the current state of the capital markets are similar to what they were in 2009. This, however, does not mean that the conditions under which the 2009 Decision was made are the same as they are today. As noted in Mr. Engen's evidence, the current period is characterized by concerns for a sustained US economic recovery, fears of an economic slowdown related to weak economic data from the US and the European Union and the European sovereign debt crisis, among other things. These are not at all descriptive

of the period in latter 2009. (Exhibit B1-9-6, Appendix E, Engen Evidence, pp. 7-8) Moreover, as pointed out by AMPC/CEC, since that time markets have demonstrated a degree of stabilization in sharp contrast to the situation preceding the 2009 Decision which followed a dramatic crash. Therefore, while there are some similarities between the current period and late 2009, the Panel is of the view there are significant differences. By contrast, the markets, while maintaining volatility, have experienced a few years of comparative stability and the investor has been distanced from the financial conditions characterizing the period leading to the 2009 proceeding.

The Commission Panel is mindful that many of the key indicators of capital market conditions are similar to those of 2009 but does not consider them alone to be determinative in reaching a decision on the cost of equity. While considering changes in capital markets, pricing models some of which reflect the market outlook, are very important in reaching a determination on the appropriate rate of return in this proceeding.

The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

The Commission Panel does not accept ICG's argument that the 2009 Decision fails to appropriately balance the interests of customers and shareholders. In the view of the Panel, there is no value in re-examining the 2009 Decision nor is there evidence to support the need for doing so.

3.2 Consideration of Other Jurisdictions

Throughout the evidentiary portion of this proceeding there has been considerable reliance among the parties upon data and cost of capital decisions from both US and Canadian jurisdictions. The Commission Panel considers these separately as the issues related to each differ.

3.2.1 Relevance of US Data and Decisions

In the 2006 Decision, two issues related to reliance upon US data in cost of capital proceedings were dealt with by the Commission:

1) Opportunities exist for investors to commit capital on a global basis. The Commission Panel noted that there was considerable foreign exchange risk and was not convinced that the Federal Government's easing of foreign content in retirement portfolios was sufficient reason to raise the equity return of a utility.
2) The necessity of looking beyond Canadian data in measuring the risk premium. The Commission accepted the use of historical and forecast data for US utilities "when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results." (2006 Decision, p. 50)

In the 2009 Decision, the Commission accepted the use of historical and forecast data of US utilities as outlined in the 2006 Decision. In addition, the Commission supported the need for utilities to compete in a global marketplace and reiterated its acceptance of the use of historical and forecasting data. In the 2009 Decision, the Commission also noted the lack of relevant Canadian data and considered the potential for US gas utilities to act as a proxy in the determination of cost of capital and credit metrics. (2009 ROE Decision, pp. 15-16)

Submissions by Parties

In the current proceeding, the FBCU take the position that the Commission should find that US data remains useful and that US utilities can be appropriate comparators based on total investment risk. In support of this, they rely on the evidence of Ms. McShane and Dr. Vander Weide who make the following assertions:

- The operating, regulatory and business environments for US and Canadian regulated companies are generally similar.
- Capital markets in Canada and the US are significantly integrated and the cost of capital environment is similar.

In further support of their argument, the FBCU note that Dr. Safir acknowledged the integration of capital markets in his evidence and utilized US companies in his Capital Asset Pricing Model (CAPM) and DCF analysis. Further, the FBCU argue that Dr. Booth, in spite of his concern with the use of US data, conceded there was a high degree of integration between US and Canadian markets. (FBCU Final Submission, pp. 96-97)

AMPC/CEC's witness Dr. Booth raised two concerns with the use of US data:

- US financial markets exhibit greater risk than Canadian markets and have generated higher premia in the past.
- Regulatory implementation differs even though US and Canadian principles of regulation are the same.

  (Exhibit C6-12, Dr. Booth Evidence, Appendix B, p. 106)

AMPC/CEC submit that there is ample support for Dr. Booth's assertion that US markets are riskier than those in Canada. They point out his evidence demonstrates that over the period 1926-2011, US returns showed greater volatility than Canadian returns and the risk premium was higher in the US than the equivalent in Canada. They further submit that during Ms. McShane's cross-examination, she agreed that a typical US utility could be viewed as higher risk than a Canadian one and point out that her report aligns with Dr. Booth's as it presents a historical risk premium of 4.7-4.8 percent for Canada compared to 5.5-5.7 percent for the US. (AMPC Final Submission, p. 46) Concerning the difference between Canada and the US with respect to the implementation of regulatory principles, AMPC/CEC state that the Commission in the 2009 Decision was cognizant of the danger of relying on US comparables and cites the following statement of the Commission Panel in that decision:

> "The Commission Panel agrees with Dr. Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short term, earn its allowed return than the Value Line US natural gas LDC enjoy." [emphasis added by AMPC/CEC]

Additionally, AMPC/CEC point to Dr. Booth's finding that Canadian utilities have higher bond ratings in spite of poorer financial ratios, which in his view reflects the importance bond rating agencies place on the differing regulatory approaches in Canada and the US. In summary, AMPC/CEC submit that the Commission should continue to approach US data based results with caution, adjusting them downward to reflect differences in financial and regulatory contexts between the two countries. (AMPC/CEC Final Submission, pp. 46-47)

FBCU argue that the evidence does not support a downward adjustment to US results and state the following:

> "Since the financial crisis, long term interest rates have been similar in Canada and the US across a broad range of bond types, equity market volatility has been virtually identical, and market risk premium surveys show virtual identical values." (FBCU Reply, p. 28)

None of the parties have suggested that the Commission should put no weight on US data and decisions.

Commission Determination

The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. **Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.**

In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. Canadian investors considering US utility investments are subject to currency exchange risk that would not be the case with Canadian utility investments. Additionally, the US regulatory

environment while similar is not identical to that of Canada. The 2009 Decision's reference to the array of deferral mechanisms resulting in greater certainty for the Canadian utility is just one example of potential differences between the jurisdictions. Moreover, Ms. McShane has acknowledged under cross-examination that the universe of US utilities is focused on vertically integrated utilities and, to the extent that there is a smaller number of Canadian investor-owned, vertically integrated utilities, the typical US utility could be viewed as higher risk than the typical Canadian utility. (T3:466-467) Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

3.2.2 Consideration from other Canadian Jurisdictions

Throughout this proceeding the parties have chosen to utilize information and related decisions from other Canadian jurisdictions as support for the position they have taken on an issue. The Commission Panel notes that decisions in all jurisdictions result from the judgment of evidence specific to a region or a particular utility that in each case is unique. To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C.

3.3 Relevance of Disparity between "Allowed" and "Actual ROE"

3.3.1 Outline of the Issue

As described in Section 2.1, when setting a rate under the subsection 60 of *UCA,* the Commission must have due regard for, among other things, whether the rate is insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. This standard does not mean, however, that a utility must be guaranteed its allowed return on equity. It simply means that a utility must be given an opportunity to earn this return. In any particular year, the actual ROE earned may be below or above the

allowed ROE. The rates are set based on a forecast revenue requirement for the year, which includes a provision for the allowed ROE, grossed up for income taxes. The utility's actual performance during the fiscal year will determine how close the actual ROE will be to the allowed ROE.

Short-run risks in general relate to a utility's ability to annually earn its allowed return on equity. The issue for the Panel, therefore, is to determine the relevance of the difference of realized and allowed ROE. From the investors' perspective, this risk relates to the relative stability of year-to-year variations in earnings or cash flows and the value of those cash flows. Therefore, the Panel first has to assess the relevance of the disparity between "allowed" and "actual" ROE in relation to the question of whether FEI faces any short-run risks. FEI has a track record of generally achieving, and often exceeding, the allowed ROE in any particular year. Does this strong track record imply FEI having "no material short-run risk, or the risk of return on capital" as claimed by Dr. Booth? (T8:1464)

FEI's track record was explored extensively in the proceeding as shown below:

- From 2002 to 2011, there was only one year when the actual ROE was below the allowed ROE, whether assessed on a pre or post earnings sharing mechanism basis. This year was 2010, when 9.42 percent was achieved as compared to the 9.50 percent allowed, resulting in a net income variance of $1.2 million. (Exhibit B1-20, BCUC 1.95.1)
- A similar trend is also apparent from 1994 to 2001. (Exhibit B1-10, BC Utility Customers 1.2.1; Exhibit C6-12, pp. 27-29)
- FBCU stated that the data set used by Dr. Booth is largely from years in which a Performance Based Rate (PBR) mechanism was in place for FEI. During the PBR period, O&M and capital were set through a formula, not based on forecast spending. The PBR formula approach was designed to result in savings to be shared with customers, primarily from the operational consolidation of three separate utilities. The Commission–approved framework expressly anticipated earnings that were above the allowed ROE. FBCU argue that when the periods under PBR are excluded, the variances between FEI's achieved return and allowed ROE from 1994 to 2011 were not that significant. (FBCU Final Submission, p. 40; Exhibit B1-20, BCUC 1.96.1.1)
- For the PBR period 2004 to 2009, after sharing, the average ROE over the period is .67 percent over the allowed ROE. (Exhibit B1-32, Rebuttal Evidence, p. 3)

Submissions by Parties

FBCU submit that the relative consistency of utility sector earnings in Canada tends to suggest lower short-term risk than for non-regulated companies, but "is not synonymous with an absence of short-term risk." (FBCU Final Submission, p. 39)

ICG submits that the Commission Panel should not accept that consistent over-earnings can be explained by PBR, and that consistent over-earning is attributable to how effectively FEI manages the regulatory risk, which it claims is its largest risk, not how effectively FEI operates the utility. ICG further argues that one should think of over-earnings during the PBR period as a regulatory benefit that can be enhanced to provide increased earnings that exceed the Fair Return Standard, and that "…the historic returns suggest that FBCU have come to expect returns that exceed a fair return." (ICG Final Submission, p. 16)

AMPC/CEC first observe that FEI has not experienced any significant risk as "the shareholder has not cumulatively lost any money whatsoever since 1994." AMPC/CEC submit that "year after year, FEI continues to face very little short-run risk, such that this pattern of consistent overearnings is clearly a long-term phenomenon." (AMPC/CEC Final Submission, p. 9)

In Reply, FBCU submit "the similarly long track record among Canadian utilities of achieving or exceeding their allowed ROE suggests that Canadian regulators have long recognized that it is reasonable for a well-managed utility to be able to achieve its allowed ROE on a consistent basis." (FBCU Reply, p. 10)

Commission Determination

The Panel notes that FBCU did not explain why, even after allowance for the sharing mechanism, the over earnings have continued. For instance, in 2011 the actual ROE was 10.15 percent as compared to the 9.50 percent allowed. Consequently, the Panel observes a noteworthy asymmetry between allowed and actual ROEs that is apparent in the frequent occurrence of annual overearnings in contrast to very few years of under earnings.

In the view of the Panel, the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control costs for each test period.

The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.

4.0 CAPITAL STRUCTURE

4.1 Definition of Risk

Dr. Booth has described the most basic definition of risk as "the probability of incurring harm, which in a financial sense means losing money." Ms. McShane agreed with this definition noting that it was consistent with her own testimony which defined risk as the probability that the utility's future returns (including the return on and of capital) will fall short of returns that investors expect and require. Mr. Dall'Antonia put a finer point on it as he described a loss as not earning a fair return or more specifically, a loss is anything that is less than the allowed ROE. (Exhibit B6-12, Dr. Booth Evidence, p. 26; Exhibit B1-15, AMPC 1.4.1; T2:123-124)

The Commission Panel takes no issue with the basic definition of risk as provided by Dr. Booth. However, for this Decision, the Commission Panel views risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognizes the risk of potential financial disruption. We also accept the distinction outlined in both the 2006 Decision and the 2009 Decision where investment risk was described as comprising the sum of business risk, financial risk and regulatory risk.

Both Ms. McShane and Dr. Booth addressed business risk in terms of short-term and long-term risks, a distinction the Commission Panel considers appropriate. Each of these is discussed separately in Sections 4.2 and 4.3.

Dr. Booth has described short run utility risk as the risk of earning a return on capital and long run utility risk as the risk of earning a return of capital. (Exhibit C6-12, p. 25) Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 39) The Commission Panel does not disagree with Ms. McShane but notes that long-term risk, which Ms. McShane outlines as being of primary importance to the utility investor, is primarily reflected in the equity structure determined for FEI considering the investors' ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: "The assessment of risks has

a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

4.2 FEI's Long-Term Risk

In the 2009 Decision, eight factors that influenced FEI's long-term risk were identified. They were:

1. Provincial Government climate and energy policies;
2. The effect of aboriginal rights issues;
3. The competitive position of natural gas relative to electricity;
4. Percentage of new construction being captured by Terasen Gas Inc. (TGI);
5. Natural gas vs. Electricity in high density housing;
6. The impact of Alternative Energy Sources on TGI;
7. Changes in demand related to fuel switching; and
8. Use of natural gas per customer account.

FBCU has stated that the same risk factors are at play in the current proceeding, although they have been expressed and organized somewhat differently. (FBCU Final Submission, pp. 47-48)
For the purposes of examining the long-term risk of FEI, items 4 and 5 related to the capture rate of new construction and the energy choice for high density housing are combined under the more general heading "Customer Growth." Items 7 and 8 related to use per customer and fuel switching related demand are also combined under the new "Market Demand and Throughput" heading. In addition, two new factors which received little or no coverage in the 2009 proceeding are addressed: "Supply Risk" and "Regulatory Risk."

4.2.1 Provincial Government Climate and Energy Policies

In the 2009 Decision, the provincial government climate and energy policies of the previous few years played a significant role. During the period leading up to the proceeding, the provincial government published the "BC 2007 Energy Plan," introduced numerous pieces of legislation (principally in the area of greenhouse gas emissions reduction) and in 2008 implemented the BC Carbon Tax. In the 2009 Decision, the Commission was in agreement with TGI's position that the climate change legislation had created a level of uncertainty which did not exist during the 2005

hearing and stated that the change in government policy "will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity." (2009 Decision, pp. 36-38)

Submissions by Parties

The Commission Panel notes that there is considerable disagreement among the parties concerning the level of risk related to provincial government climate and energy policies. In the current proceeding, FBCU have ranked political risks in the number 2 risk category and submit that the risks associated with policy and legislation are equal to if not greater than in 2009. FBCU note that all of the legislation and policy relied upon by the Commission in the 2009 Decision remains in place and the introduction of the *2010 Clean Energy Act (CEA)* has had the following impacts:

- It has precluded natural gas utilities from using incentives to promote fuel switching (electricity to gas).
- It has required the Commission to account for enumerated energy objectives in the course of considering certain types of applications.

(FBCU Final Submission, pp. 53-56)

Both BCPSO and AMPC/CEC submit that conditions are far more favourable today and the resulting political risks are much lower today than TGI portrayed in 2009. In support of these submissions, they point to a number of factors:

- the lack of plans to increase the carbon tax;
- the introduction of the BC Natural Gas Strategy and its support of natural gas as a transportation fuel; and
- a collapse of the Western Climate Initiative and lack of progress on emissions-trading initiatives.

(BCPSO Final Submission, pp. 15-16; AMPC Final Submission, pp. 22-23)

Commission Determination

The Commission Panel finds that the risks related to provincial government climate and energy policy are less significant when compared to the period leading up to the 2009 Decision. At the time of the 2009 proceeding, there was considerable concern and uncertainty related to provincial

energy policies, how they would be shaped in the future and what impact this would have on Terasen's gas utilities. In addition, the Commission placed importance on the Nyboer Report as reflected in the following statement:

> "In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers." (2009 Decision, p. 37)

The Commission Panel does not consider the current environment to be as threatening to FEI as it was perceived to be in the period leading to the 2009 Decision. As BCPSO points out, there are no plans to raise the carbon tax beyond the current $1.50 per GJ level and as AMPC/CEC reports, the Western Climate Initiative has collapsed and emission trading has become a dormant issue. These all reflect a less threatening current environment and with it, a lessening of risk associated with provincial government climate and energy policies.

4.2.2 Aboriginal Rights

In the 2009 Decision, the Commission Panel acknowledged that risks posed by First Nations did not exist previously and to the extent that they were currently perceived, represented an increase in risk over natural gas local distribution companies operating in other provinces. However, the Commission did not consider that risks posed by First Nations cast doubt over Terasen Gas Inc.'s "ability to earn a return on or of its capital." (2009 Decision, p. 37)

Submissions by Parties

FBCU acknowledge that aboriginal rights issues, which they rank in category 2, are much the same now as they were in 2009 and note that this issue was not addressed by the parties in IRs or at the hearing. (FBCU Final Submission, p. 49)

BCPSO argue the amount of aboriginal rights risk should be reduced relative to 2009, given the FBCU experience and understanding of aboriginal rights and title claims resulting from First Nation consultations tied into CPCN Applications. (BCPSO Final Submission, p. 17)

AMPC/CEC submit that this risk remains unchanged from 2009 where it was given no weight and this remains appropriate. (AMPC/CEC Final Submission, p. 24)

Commission Determination

The Commission Panel agrees with the FBCU and AMPC/CEC and find that there is no evidence to suggest that there has been a significant change to risk associated with aboriginal rights based on the evidentiary record of this proceeding. We also concur with the 2009 Decision that the risk associated with aboriginal rights has little impact on the FEI's ability to earn a return.

4.2.3 Competitive Position of Natural Gas Relative to Electricity

The competitive position of natural gas to electricity is an existing risk which bears scrutiny at each cost of capital proceeding. In the 2009 Decision, the Commission Panel took note of the interveners' position that the risk related to the competitive price of natural gas and electricity had diminished since 2005. However, the Panel considered that the competitive edge which existed was dependent on too many significant variables to be considered permanent. (2009 Decision, p. 36)

Submissions by Parties

The FBCU acknowledge that natural gas prices have fallen but submit that this occurred prior to the 2009 Decision and take no issue with the fact that the development of shale gas is a "game changer" or that there has been an increase in electricity prices. They do take issue with Dr. Booth's conclusion that long-term business risk has declined since 2009 and argue that his reliance on considerations related to cost-effectiveness paints an incomplete, distorted view of FEI's overall competitive position. FBCU make the following arguments in support of their position:

- Natural gas prices fell substantially prior to the 2009 hearing due to shale gas development and this was reflected in the evidentiary record leading to the 2009 Decision.
- Volatility in natural gas prices affect natural gas to electricity competitiveness and has increased due to the suspension of hedging instrument tools resulting from the 2011 Price

Risk Management Decision (PRMP Decision).[5] Looking ahead to 2017 there is a wide potential price range for natural gas based on the AECO Forward Curve. (see Figure 2 below)

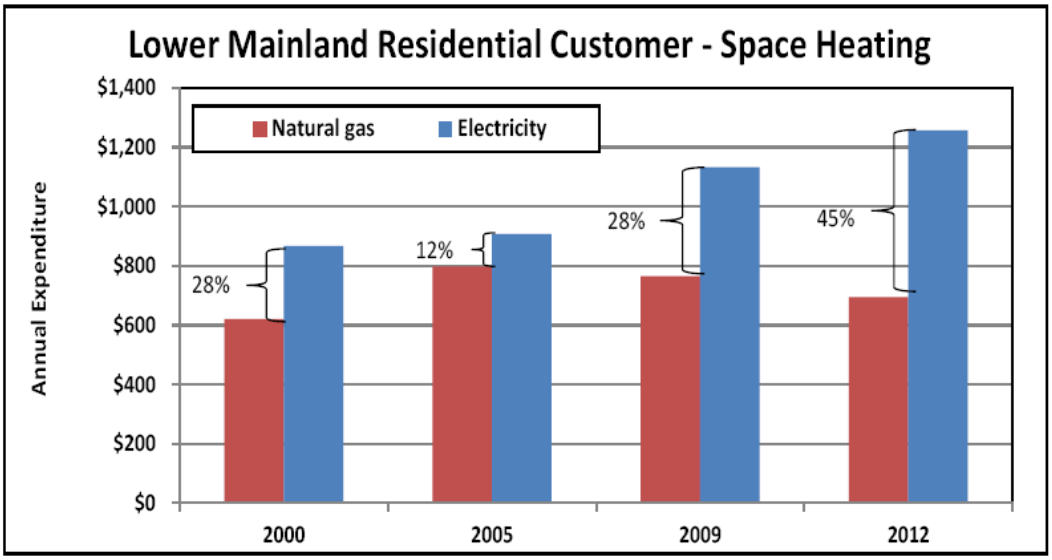
- The price of the natural gas commodity has decreased but the delivered cost of natural gas remains almost the same as 2009.
- Higher capital costs for natural gas heating materially diminish the operating cost advantage of natural gas over electricity.
- Non-price factors such as the desire to create a smaller carbon footprint have resulted in more customers being willing to adopt lower carbon and renewable energy sources.

(FBCU Final Submission, pp. 57-71)

ICG, relying on Figure 1 below, argues that there has been a significant improvement with respect to cost competitiveness between natural gas and electricity since both the 2005 and the 2009 proceedings.

Figure 1: Estimated Annual Expenditure

Figure 1: Estimated Annual Expenditure for FEI Lower Mainland Residential Customer – Natural Gas and Electricity for Space Heating

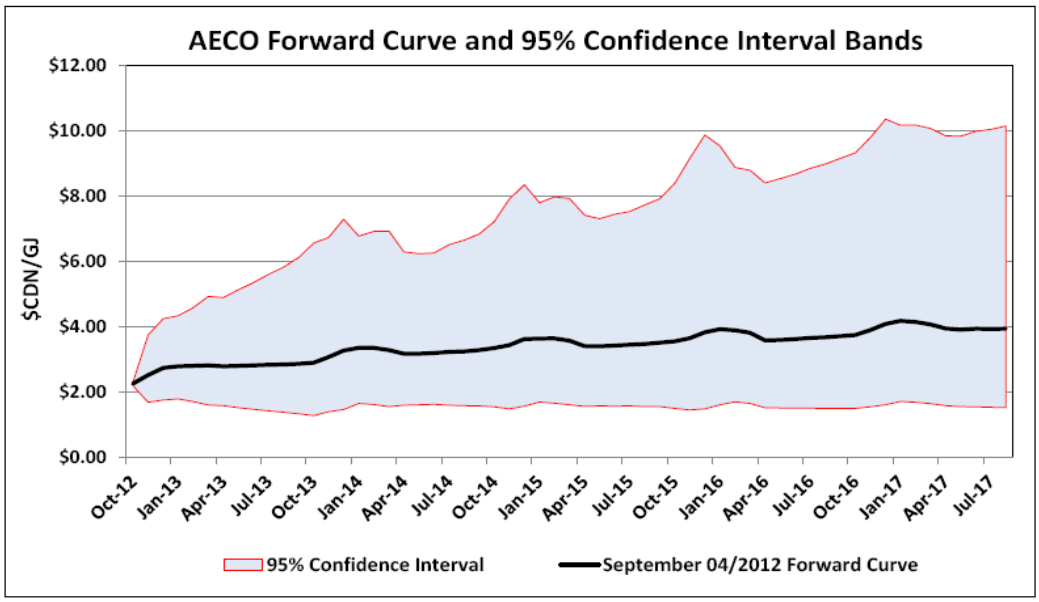


(Source: Exhibit B1-11, FBCU Response to BC Utility Customers, 1.4.2)

ICG contends that shale gas has been a game changer for natural gas prices, which has resulted in a "seismic" shift in the competitiveness of natural gas versus electricity. (ICG Final Submission, p. 11)

[5] Order G-163-11

Figure 2: AECO Forward Curve



(Source: Exhibit B1-20, BCUC 1.105.1)

BCPSO notes that there has been no change in FBCU's rating of capital cost and it is the same as in 2009. It argues there is no evidence that the effect of higher capital costs will offset any competitive gain made through lower commodity prices. Further, BCPSO submits that the AECO Forward Curve relied upon by FBCU demonstrates only an increasing level of price uncertainty over time, not volatility. BCPSO also takes issue with the FBCU claim that there is effectively no reduction in the customers overall bill. The important comparison is not natural gas against itself but against electricity, and this comparison is very favourable to FEI. (BCPSO Final Submission, pp. 9-10)

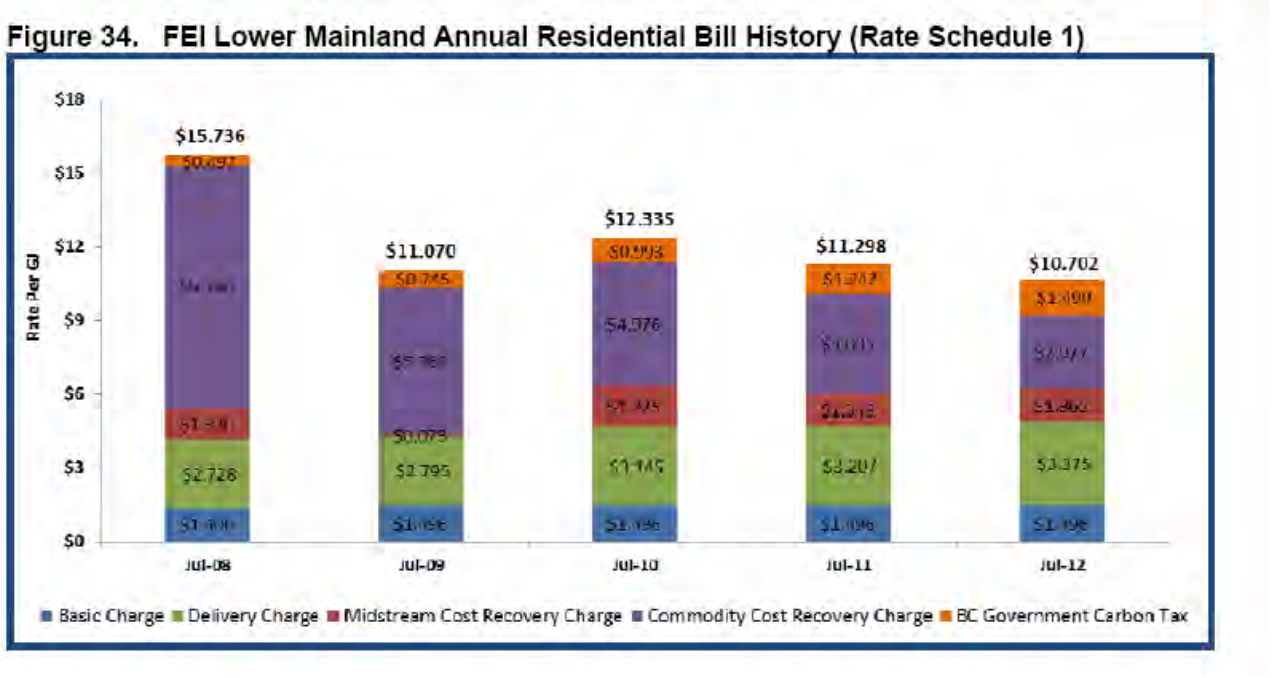
AMPC/CEC state that price is a key determinant of natural gas competitiveness and deserves the greatest weight when considering changes to FEI's business risk. In answer to FBCU's claim that the delivered cost of natural gas is similar to 2009, AMPC/CEC argue that prices are at or near a ten-year low and by FBCU's evidence (in Figure 3 below) are lower than 2009 and even more so when compared against 2005. (AMPC/CEC Final Submission, pp. 11-13)

AMPC/CEC assert that the volatility is manageable through options, including equal payment plans and deferral accounts which FEI currently uses. AMPC/CEC notes than in addition to these options, FEI is proactive in communicating the natural gas cost advantage relative to other sources.

AMPC/CEC also submit that a telling point with regard to competitiveness is how it compares to electricity. They assert that FBCU's response to AMPC/CEC 1.4.2 (Exhibit B1-15) outlines the savings of natural gas over electricity for space heating (and to a lesser extent water heating) and demonstrates a trend that continues to widen. In their view, this information demonstrates that FEI is the beneficiary of both a reduction in gas prices and rising BC Hydro rates. (AMPC/CEC Final Submission, pp. 11-16)

In Reply, FBCU argue that using November 2009 rather than July 2009 is a more appropriate point of comparison and represents a variance of less than 3 percent. They also point out that this difference has been insufficient to drive behavioral changes in new and existing customers. (FBCU Reply, p. 14)

Figure 3: Delivered Cost of Natural Gas



(Source: Revised Exhibit B1-9-6, Appendix H, p. 51, Figure 34)

Additionally, FBCU state that they have not suggested that there is an increase in price volatility, but rather they have fewer tools to deal with it. Overall, FBCU submit that commodity price volatility is a risk factor which remains undiminished since 2009. (FBCU Reply, pp. 14-15)

Commission Determination

The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk. **The Commission Panel finds that there has been some reduction in the level of risk associated with the competitive position of natural gas as compared to electricity.** It is difficult to reach any other conclusion given there has been a reduction in the total billing costs while over the same period the cost of electricity has risen regardless of the timeline one chooses for comparison. The evidence relied upon by the interveners in Figure 1, which details the growing variance between natural gas and electricity, is persuasive and it is unlikely that a price conscious customer would move away from natural gas in these circumstances. Looking ahead, and relying upon the information in Figure 2 above, the Panel notes that in spite of the range considered to fall under the 95 percent interval band, the September 4, 2012 AECO Forward Curve projects relatively stable natural gas commodity costs looking out to 2017. While hardly definitive, this does point to some level of stability over the next few years.

Notwithstanding these favourable conditions, the Commission Panel does place some weight on the lack of change in the purchasing behaviour of new and existing customers. In our view, some of this relates to the higher capital costs required to convert to or install natural gas service and the move to multi-family dwellings, which is discussed in Section 4.2.4.

FBCU state that price volatility is a risk factor that remains undiminished since 2009. Based on the evidentiary record we agree. However, we are not in agreement with the assertion that FEI have fewer tools to manage volatility. In the PRMP Decision, the Commission Panel offered a number of suggestions or options FEI may wish to consider. Included among these was offering the PRMP program to existing customers on a permission basis. There is no evidence before the Panel to indicate any action that FBCU has taken to bring alternatives forward.

4.2.4 Customer Growth

Submissions by Parties

FBCU note that a continuing trend has been its lower capture rate on new construction and reports a decline in the rate of net residential customer additions when 2011 is compared against 2007. In addition, the FBCU submits that new customer usage is roughly half what it used to be and therefore, the trend that existed in 2009 has not changed. FBCU states that this trend is closely associated with growth of multi-family dwellings in BC, a market where FEI has low penetration driven by unfavourable installation economics. This shift toward multi-family dwellings means that FEI's capture rate will further decline over time. (FBCU Final Submission, pp. 50-51; Exhibit B1-9, Appendix H, pp. 33-37)

AMPC/CEC point out that in spite of the challenges faced by FEI in growing customers, its total customer base continues to grow. The number of residential customers grew by 8 percent over the period 2005-2011 and the number of commercial customers grew by 5 percent over the same period while there was some decline in the number if not the consumption of industrial customers. (AMPC/CEC Final Submission, pp. 16; Exhibit B1-11, BCUC 1.4.4)

Commission Determination

The Commission Panel notes that the circumstances related to unfavourable installation economics and the shift toward multi-family dwellings existed at the time of the 2009 Decision. In spite of this, the total number of customers continues to grow if not the market share of potential new customers. **Therefore, the Commission Panel finds that there is no persuasive evidence to suggest there has been a shift in risk related to customer growth.**

4.2.5 Impact of Alternate Energy Services on FEI

Submissions by Parties

FBCU state that the "adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business for providing natural gas for space and water heating." The recent number of energy projects approved serves to demonstrate the momentum behind

alternative energy which FBCU rate in the number 2 risk category. In FBCU's view, the growing consumer awareness of alternative energy and its green attributes and increasing cost effectiveness demonstrate the importance of this risk factor for FEI. (FBCU Final Submission, p. 52; Exhibit B1-9, Appendix H, p. 28)

AMPC/CEC argue that this represents double counting and there is no evidence to suggest that there is more risk posed by alternative energy to FEI than that which existed in 2009. Further, they argue that the new transportation technology will result in improved prospects as it allows natural gas to replace diesel in heavy trucking thereby increasing natural gas demand in the future. (AMPC/CEC Final Submission, p. 18)

Commission Determination

The Commission Panel notes that the impact of AES sources on FEI is not a new risk. However, we do acknowledge that in the three years since the 2009 proceeding, there has been greater momentum behind alternative energy forms and the adoption of new technology related to them. Therefore, the Panel is mindful that there is the potential for an increase in risk related to AES but, given that much of this risk has been accounted for in reference to FBCU's share of multi-family dwellings, it is difficult to quantify.

4.2.6 Market Demand and Throughput

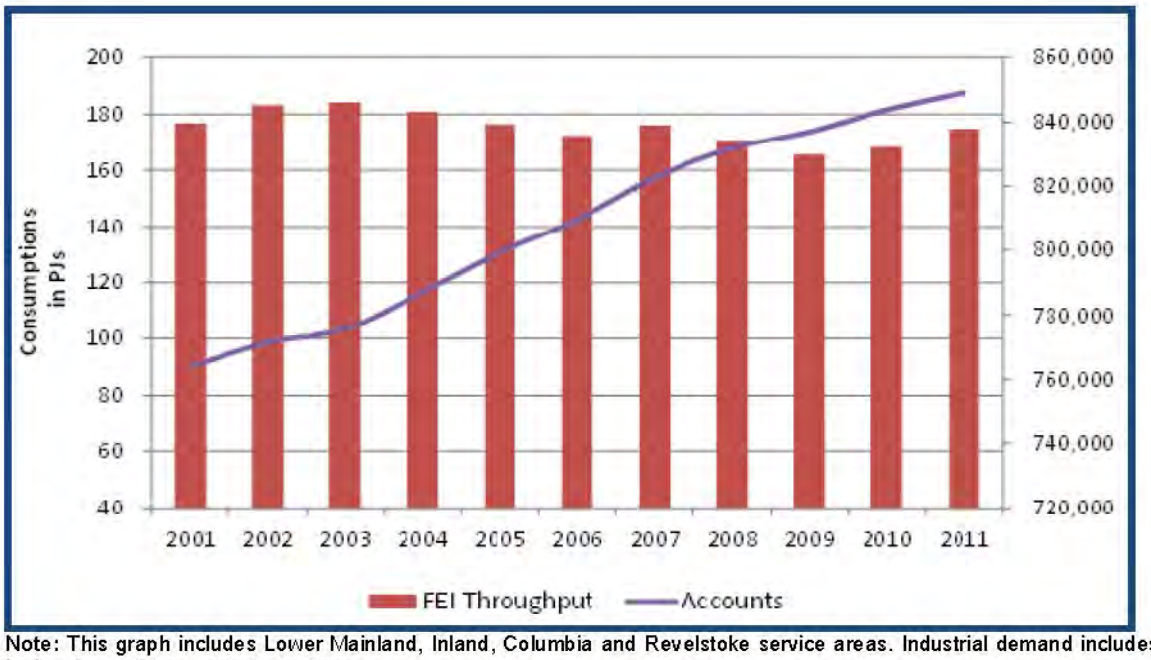
Submissions by Parties

The FBCU state that FEI's use per customer (UPC) for both new and existing customers has been declining; this trend, based on a Conservation Potential Review Study, is expected to continue until 2030. Contributing to this decline are a variety of factors including technological advances and energy efficiency improvements. In addition, the decline in UPC can, in part, be attributed to increased efficiency standards, better building envelopes and a move to smaller dwellings. Further, FBCU state that new construction research since the 2009 hearing shows that natural gas has been increasingly used as a secondary fuel source in new homes rather than the primary source. The FBCU state that there is no reason to believe the drivers behind these market trends will cease. (FBCU Final Submission, pp. 52-53; Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

ICG states that Exhibit B1-41 shows that there has been no decline in system throughput since 2009. In addition, ICG asserts that there is an upward trend in industrial throughput, which is reflective of lower natural gas prices over the same period. Given this recent trend, ICG argues that the Commission should not accept the FBCU's 2013-2016 lower industrial throughput evidence and conclude that business risks are in fact lower than in 2009. (Exhibit B1-41, Undertaking No. 6, p. 3; ICG Final Submission, pp. 7-9)

BCPSO notes that the Commission acknowledged the risks related to throughput in its 2009 Decision and, as a result, they are not new. BCPSO, like AMPC/CEC, further submit that based on graphical information in Figure 4 below, the trend of declining throughput has reversed itself in 2009 and has increased each year since. (BCPSO Final Submission, pp. 13-14)

Figure 4: FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



Note: This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

(Source: Exhibit B1-9-6, Section H, p. 9)

AMPC/CEC submit that the evidence presented by FBCU shows that both commercial and industrial UPC has increased since 2009, while residential UPC has decreased only marginally.

AMPC/CEC further submit that as the Commission considers the issue of declining UPC, it should consider two points:

- The residential throughput would have to decrease by 83 percent in 2012 to drive its distribution margin to a level equal to BC Hydro Tier 2 Rates; and
- The negative trend related to the creation of energy efficiency is no different than that faced by BC Hydro.

AMPC/CEC argues that these energy trends are not new and there is only risk if they affect the utility's ability to earn a fair return which, in their view, is not supported by the evidence on the record. (AMPC/CEC Final Submission, pp. 16-18)

In Reply, FBCU submit that revenues related to increased throughput are largely unaffected due to the structure of industrial contracts that only generate additional revenue if consumption exceeds an agreed upon level. Therefore, the declines in residential and commercial UPC continue to have a disproportionate impact on FEI. FBCU also point out that AMPC/CEC's reliance on Tier 2 rates is inappropriate. In addition, they argue that the AMPC/CEC's position is based on the view that existing customers will not leave natural gas until there is no longer a price advantage. FBCU state that this assumption is unwarranted given recent research that people are less committed to natural gas, irrespective of price. (FBCU Reply, pp. 16-17)

Commission Determination

The Commission Panel finds that there is insufficient evidence to support a finding that there has been a shift in risk related to market demand and throughput.

The Commission Panel notes that the decline in UPC and overall throughput were issues raised in the 2009 proceeding. Based on the evidence in this proceeding, it is apparent that the overall throughput has increased since 2009 and UPC, while decreasing overall, has increased for both commercial and industrial customers. In the view of the Panel, these are all positive but not conclusive signs.

The Commission Panel places little weight on the FBCU submission that the increased throughput has not resulted in increased revenue due to the structure of industrial contracts. Notwithstanding our understanding that industrial contracts are subject to competitive negotiations, in our view, FBCU nonetheless has some control over the structure of and risks related to the contracts it negotiates.

The Commission Panel does not consider the research indicating existing customers are less committed to natural gas in spite of the price advantage to be persuasive. The Panel notes that much of the research referred to in this context was related to AES options, which have been considered as part of the growth of multi-family dwellings addressed in Section 4.2.4. (Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

4.2.7 Supply Risk

Submissions by Parties

FBCU's position is that BC's shale deposits do not guarantee a reliable supply of natural gas at reasonable prices. Due to the higher cost of development relative to other areas and a lack of infrastructure for resource development and market connection, FBCU state that growth of production in northeastern BC has stopped and there is risk of current levels declining. This is in contrast to developments like the Marcellus Formation in the northeast part of the continent that is thriving. FBCU submit that this leads to the possibility of stranded resources or, at a minimum, higher market prices and an expansion of access infrastructure to encourage expansion of BC's shale gas resources.

FBCU also submit there is a lack of new development of infrastructure to move gas to FEI's service territory. They argue that the development of gas transmission infrastructure projects connecting BC sources with Alberta and Eastern markets, combined with the potential for LNG exports, could change the historical pricing relationship between BC supply and Alberta production leading to higher consumer prices in the future. (FBCU Final Submission, pp. 60-61)

AMPC/CEC describe the potential for stranded resources in northwestern BC as nonsensical. They submit that the impact of shale gas development on prices was not recognized, as it was not mentioned in the 2009 Decision. They also refer to the following statement of Ms. Des Brisay in the current proceeding:

> "What was not fully understood is how low the cost could be in terms of how we produced that resource, and that's really where we have seen the shifting of the curve has been as we have a better understanding of the economic feasibility of the development of shale gas reserves in different parts of North America." (T2:161)

Therefore, AMPC/CEC argues the existence of reserves may have been known in 2009, but the understanding of the economic feasibility of development has shifted since then. (AMPC/CEC Final Submission, p. 19)

AMPC/CEC submit that any weight the security of supply factor deserves pales when compared to the availability of supply. The Commission Panel notes they did not comment directly on the potential change to the historic pricing relationship between Alberta and BC. (AMPC/CEC Final Submission, pp. 18-20)

As noted previously, FBCU acknowledge that shale gas has been a "game changer" and that supply risk has declined. They did make the following points:

- There was knowledge of natural gas reserves prior to the 2009 proceeding.
- The price of natural gas must be higher (leading to higher rates) before supply will be extracted.
- FEI's ability to access cost effective supply could be challenged as there are competing markets for natural gas.

FBCU argue that it is the factors affecting demand for delivered natural gas, not energy supply considerations, that are the key supply risk for FEI. (FBCU Reply, pp. 19-20)

Commission Determination

The Commission Panel finds that there has been a decrease in the risk associated with the supply of gas but an increase in the risk associated with access to this gas at low prices. Balancing the two, there has been no material change in the level of risk related to energy supply.

The Commission Panel accepts the statement of Ms. Des Brisay as informative and a reasonably accurate reflection of where matters stood at the time leading up to the 2009 Decision. There is clearly no disagreement among the parties with respect to the existence of adequate supply of natural gas and FBCU have conceded that the actual supply risk has declined. Therefore, the issue is not whether natural gas will be available but whether sufficient natural gas will be available at the low commodity price levels that the consumer has come to expect. To this end, FBCU have laid out a number of facts and potential scenarios which they argue will have a significant impact on the supply of low cost natural gas. None of the interveners have challenged this information except AMPC/CEC who characterized the potential stranding of assets as "ludicrous."

In our view, the potential for some of FBCU's concerns to become a reality cannot be dismissed. The stability of the current environment remains uncertain, as does the magnitude of future development of the LNG business. Until this has been determined, the continuity of current low price levels for natural gas will be at some risk. However, the risk of supply to the extent that it existed, has abated and shifted to the risk associated with maintaining existing commodity price levels with no resulting increase in overall risk.

4.2.8 Regulatory Risk

Submissions by Parties

FBCU has ranked regulatory risk as their highest risk area with a number of factors in the "higher risk" category. In assigning this weighting, FBCU states that FEI is dependent on regulatory approvals that determine its revenue requirements, cost of service recovery and approval of investments. FBCU submit that the pace of change in the energy policy and environment has

increased at a time when the Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment and added process as compared to 2009. (Exhibit B1-9-1, Section H, pp. 5-6)

BCPSO points out the FBCU witnesses have confirmed that the regulatory environment is predictable and stable and regulatory risk should not be viewed as its number one risk factor. (BCPSO Final Submission, pp. 14-15)

AMPC/CEC questions the FBCU ranking of regulatory risk as there is no compelling evidence to suggest that FEI faces greater regulatory uncertainty than it did in 2009. (AMPC/CEC Final Submission, pp. 10, 20)

In Reply, FBCU acknowledge that the relative stability and predictability of the BC regulatory framework reduces regulatory risk. However, they point out that the breadth of the Commission's influence on FEI's business is undeniable and individual decisions can have significant implications for FEI particularly in the short-term. While they identify "regulatory risk as being 'higher,' any change since 2009 was not material to FEI's overall risk." (FBCU Reply, p. 12)

Commission Determination

The Commission Panel finds that there has been no material change in the level of risk associated with regulatory risk.

The Commission Panel accepts that the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI. However, we agree with the parties that argue there has not been a material change since the 2009 Decision.

4.3 FEI's Short-Term Risk

There are two issues that must be considered by the Commission Panel with respect to short-term risk. The first is whether there has been a change in short-term risk since the 2009 Decision. The second is how much of FEI's short-term risk has been mitigated and, as a result, how much of the remaining risk must be considered. In the view of the Commission Panel, this will be determinative

as to the level of weight to be placed upon the short-term risk in this proceeding. FBCU has expressed disagreement with the need to determine the level of short-term risk in reply to BCSPO submissions:

> "The Commission need not attempt to characterize or quantify FEI's short-term risk to determine a fair return for FEI. The question requiring a determination is the extent to which FEI's short-term risk has changed since 2009." (FBCU Reply, p. 9)

The Commission Panel disagrees. There are many measures of risk. The overall level of risk may not have changed substantially but one needs to consider the individual risk elements and their weighting. These may have changed and therefore, not considering them may be a mistake.

4.3.1 Change in Short-Term Risk

Submissions by Parties

The FBCU submit that short-term risk is essentially the same as in 2009. (FBCU Final Submission, p. 45)

Both FBCU and the interveners have focused their submissions on two areas in examining short-term risk:

- FEI's record of generally being able to earn its allowed ROE; and
- The amount of risk mitigation provided by deferral accounts.

Matters related to FEI's history of typically earning its ROE were dealt with in Section 3.3, where it was determined that actual earnings versus approved earnings history is more appropriately a matter for consideration in revenue requirements proceedings.

Concerning the use of deferral accounts, FBCU submit that "FEI's ability to manage short-term risk with deferral accounts is a function of the portion of the overall revenue requirement covered by deferrals, irrespective of the number of accounts providing that coverage." They also submit that there has been no material change in the collective scope of deferrals having an effect on earnings

volatility. In the view of FBCU, their evidence on deferral accounts shows that the percentage of revenue requirements covered by deferral accounts has decreased and has resulted in a credit to customers. (FBCU Final Submission, pp. 38-45)

AMPC/CEC acknowledge that some of the additions in deferral accounts since 2009 are a reflection of accounting changes, but submit that three new accounts (Compliance to Emission Regulation Account, Customer Service Variance Account and Depreciation Variance Account) are significant. They further submit that while the new accounts may not represent a monumental change, they are an indication of FEI's ability to obtain such accounts. Therefore, this risk factor is lower today than in 2009. (AMPC/CEC Final Submission, p. 22)

BCPSO agrees with the submissions of AMPC/CEC and submits that the addition of the three new accounts demonstrates the Commission's willingness to mitigate the impact of short-term uncertainties. It concludes that the new accounts indicate short-term risk is no greater and likely less. In sum, BCPSO submit that short-term business risk is lower than in 2009. (BCPSO Final Submission, pp. 8-9)

FBCU, in reply, assert that the submissions of AMPC/CEC are at odds with the evidence of their witness, Dr. Booth, "who admitted that FEI risk hadn't changed "in the slightest."" The Commission Panel notes that Dr. Booth (T8:1475) was referring to ROE and not overall risk. FBCU conclude that short-term risk when compared to risk faced by its peers in other jurisdictions, remains unchanged. (FBCU Reply, p. 9)

Commission Determination

The Commission Panel, after reviewing the evidence, finds that there has not been a material change to FEI's short-term risk since the 2009 Decision. However, to the extent that there have been additional deferral accounts added, there is a greater ability to mitigate short-term risk. The Commission Panel agrees with BCPSO that the Commission's approval of the new deferral accounts demonstrates a willingness on the part of the Commission to mitigate the impact of uncertainty. However, in the Panel's view it is not important how the deferral account came to be. It is the

effect. Therefore, the fact that the Depreciation Variance Account was ordered by the Commission, as noted by FBCU, in our view, is immaterial. More important is the fact that the deferral account now exists, as it reduces the risk associated with unforeseen variances in depreciation amounts.

4.3.2 Magnitude of Short-Term Risk

The second question to be considered by the Commission Panel with respect to short-term risk relates to the level of mitigation which has or could be applied against short-term risk. Much of the evidence related to this was focused on the use of deferral accounts which we explore below.

Revenue Related Deferral Accounts

The FBCU consider the overall risk for residential and commercial sales to be moderate and have assessed the risk of industrial sales to be high.

In 2011, residential and commercial sales accounted for 87.9 percent or $485.4 million of the total delivery margin revenue of $552.3 million. FBCU are protected for changes in use per customer for residential and commercial sales through the Rate Stabilization Adjustment Mechanism (RSAM). In assessing these risks as moderate, FBCU point out they are not protected for any differences in actual and forecast number of new customers in a given test period. The Commission Panel notes that impact of any variance in customer additions is likely to be minor, given the relatively small number of new customer additions as a function of the existing customer base. **Given the relatively heavy reliance on existing customers for most of the revenue and the existence of the RSAM, the Commission Panel finds the short-term risk related to residential and commercial sales to be low rather than moderate as suggested by FBCU.**

Industrial sales account for 12.1 percent or $66.8 million of the delivery margin revenue in 2011. FBCU assess the risk as high in this area because there are no deferral accounts utilized with this customer group. (Exhibit B1-20, BCUC 1.96.1)

In reviewing the submissions, the Commission Panel notes the following statement made by FBCU in reply to AMPC/CEC submissions: "Increased consumption by industrial customers only generates additional revenue if the consumption **exceeds a customer's fixed contract demand** (i.e., the 'take

or pay' volume)." [emphasis added] Notwithstanding the impact on revenue as addressed in this statement, it appears to the Panel that the lack of deferral accounts in the industrial category is because there is no need as this area is run on a contract basis with a reliance on "take or pay" contracts. (FBCU Reply, p. 16) It is therefore evident that potential risk is mitigated to a large extend by the existence of such contracts. **For these reasons, the Commission Panel finds that a "high" risk rating for industrial sales is inappropriate and a moderate to low rating is more appropriate to the level of risk.**

Expense Related Deferral Accounts

Table 1 of the FBCU response to BCUC IR 1.96.1.1 indicates that in 2011, 75.3 percent ($1,160.7 million) of the FEI revenue requirement or 31.0 percent ($171.1 million) of the Revenue Margin Delivery Requirement was covered by way of deferral accounts. Overall, the single biggest expense item was cost of gas, which at $989.6 million is 100 percent covered by deferral mechanisms.

FBCU's Operation and Maintenance (O&M) Expense totalled $184.6 million. Of this, approximately 9 percent encompassing Pension & OPEB Variance, Insurance Variance and BCUC Levies Variance Deferral is covered by deferral accounts. FBCU rates the overall risk of O&M Expense as high citing the small portion covered by deferral accounts in explanation.

The Commission Panel also notes that of the remaining revenue requirements categories, Property and Sundry Taxes ($50.2 million), Financing Costs ($108.5 million) and Depreciation and Amortization ($99.9 million) are at or near 100 percent deferral account protection levels. (Exhibit B1-24, BCUC 2.182.1; Exhibit B1-20, BCUC 1.96.1)

The most significant area not covered to a large degree by deferral accounts is O&M Expenses. O&M Expenses are also an area where there is a history of under spending approved O&M amounts. Under cross-examination, Mr. Dall'Antonia explained that risks at the start of each test year are the same and the success of managing within budgets can be attributed to management's experience and being sound managers. (T3:344) While the Commission Panel does not take issue with Mr. Dall'Antonia's comments, we are of the view that in addition to this, FEI has a broad range of options available to it to manage O&M budgets effectively. For example, many of the initiatives in an approved O&M plan can be postponed for short periods or in some cases not implemented

within the test period. This could include items such as routine maintenance, new staff additions, replacement of staff vacancies or delaying of new programs or initiatives. This may, in part, account for the fact that O&M expenditures were less than forecast in 8 of the last 9 years. (Exhibit B1-24, BCUC 2.182.1) Therefore, in the view of the Commission Panel, this is an area where FEI has a high degree of control. **Accordingly, the Commission Panel finds that a high risk rating for O&M expenses is not appropriate and a moderate to low rating is more reflective of the risk FEI faces.**

Another area with a high risk rating due to limited use of deferral accounts is Other Operating Revenue which encompasses things like late payment charges, NSF cheques, and connection charges. This item has been in the $20 to $25 million range over the last nine years, which is a relatively small part of revenue requirements. However, as outlined in Undertaking No. 8, there have been consistent negative variances (meaning revenues were less than approved) in the $2 million range for all but the most recent completed year. (Exhibit B1-24, BCUC 182.1; Exhibit B1-20, BCUC 1.96.1; T2:293-294; Exhibit B1-43)

The Commission Panel acknowledges that many of the Other Operating Revenue areas are less predictable and controllable in nature and most items are not covered by deferral accounts. Therefore, the Commission Panel finds that a high risk rating is appropriate.

Commission Determination

Given our findings with respect to revenue risks and risks in expense areas not covered by deferral accounts, the Commission Panel is not persuaded that on balance FEI faces significant short-term risks to its achieving its allowed ROE in a given test period. While including items that are less predictable or controllable, the Other Operating Revenue item generally shows a consistent pattern of under earning revenues. However, their impact on the total revenue requirements is relatively small. **Therefore, acknowledging that there has been little change in short-term risk since the 2009 Decision, the Commission Panel has determined that only minimal weight can be given short-term risk as an impediment to earning a fair return.**

4.4 Developing an Optimal Capital Structure

An important component of the Panel's task is to determine an allowed capital structure. This section is devoted to the discussion of the evidence presented that relates to the capital structure decision and presents the Commission Panel's findings. In this section, we set out the context within which this evidence has been considered.

4.4.1 Capital Structure and the Fair Return Standard

Background on the role of capital structure on the cost of capital is provided in the Brattle Report, which recognizes that "underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return." In addition, the result of a specific capital structure is a particular Weighted Average Cost of Capital.

$$WACC = r_d(1 - T_C).\frac{D}{V} + r_E\frac{E}{V}$$

where: r_d = market cost of debt; r_E = market cost of equity; T_C = corporate income tax rate; D = market value of debt; E= market value of equity; and V = the market value of the firm (i.e., V= D+E).

(Exhibit A2-3, pp. 38-40)

This cost of capital reflects the equity risk and the debt risk, both of which in turn reflect both operating and financial risk, as well as the tax advantage of debt.

The integration of the capital structure decision with the ROE decision is recognized in the argument of AMPC/CEC:

> "Capital structure is important for two main reasons: (1) the cost of equity is higher to reflect the greater risk of investing in shares as opposed to bonds, and (2) the cost of debt (interest) is tax deductible, whereas the cost of equity (dividends) is paid out of after-tax income. Consequently, equity is substantially more expensive than debt. . . . FEI's customers have a right to expect that its capital structure will be efficient and the common equity component will reflect the real risks equity shareholders are exposed to." (AMPC/CEC Final Submission, p. 32)

Ms. McShane submits that the inter-dependence between capital structure and ROE is largely based on the FRS with its three requirements i) the ability to attract capital on reasonable terms, ii) maintenance of financial integrity; and iii) comparability of returns. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 34)

These considerations translate into a focus on credit metrics and the need to maintain a particular credit rating. The FBCU does, however, discuss at length the possible disruptions that might take place if FBCU experienced a rating downgrade. AMPC/CEC submit that FBCU's credit metrics are not weak and that a 35 percent common equity ratio (as compared to its existing 40 percent ratio) "is entirely consistent with the objective of maintaining FEI's existing credit rating." (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 35-37; FBCU Final Submission, pp. 12-15; AMPC/CEC Submission, pp. 32, 34-36)

4.4.2 Commission Panel Discussion

The Commission Panel accepts the view put forth by AMPC/CEC that the capital structure should be set efficiently. The Panel also notes that debt comes with advantages, primarily the deductibility of interest payments from taxes.

At the same time, the Commission Panel recognizes the argument made by FBCU that the excessive use of debt could disrupt the operations of the company by making it difficult to finance the ongoing operations.

The Commission Panel accepts, therefore, that there are both expected benefits and expected costs associated with the use of debt. The task faced by the Panel is to determine the 'optimal' capital structure, one that is efficient in reducing the total or WACC through the use of debt without creating potential financing disruptions that could offset these benefits to the point where the net benefit is reduced.

The discussion of the capital structure evidence and determination found in this section reflects the Panel's desire to find an efficient or optimal capital structure. In doing so it applies the following principles to guide its analysis:

1. While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of the attendant costs and benefits.
2. The long-run risks discussed by all parties are important considerations in determining an optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management. Since the concern is with financial disruption, both diversifiable and non-diversifiable risks must be recognized in assessing the risk of financial disruption.
3. The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility. It is in this sense that the Panel agrees with FBCU's view that FEI is not a diversified investor. (FBCU Final Submission, pp. 130-131) As discussed in Section 5, however, this does not imply that the Panel accepts this view with regard to the ROE.

4.5 Credit Ratings and Metrics

An important issue for the Commission Panel is to determine how important it is for FEI, as the benchmark utility, to maintain an "A" category credit rating among credit agencies. Credit ratings are important indicators of potential financial disruption as discussed in Section 4.4. A lowering of credit agency ratings raises concerns about the cost of debt and access to the credit market at reasonable cost. Therefore, there are clearly advantages of maintaining an ROE and capital structure which will allow for existing credit agency ratings to be maintained. However, the Commission Panel must consider whether there is a point where maintenance of a particular credit rating may result in a capital structure or ROE that is suboptimal in the circumstances. In such instances, what importance should the Commission Panel place on the maintenance of a credit rating and at what additional cost?

Presently, FEI is rated by Moody's and DBRS, with Moody's providing the lower credit rating at A3, which is just one level above a Baa rating. DBRS provides a slightly higher A rating, which is comparable to a Moody's A2 rating. (Exhibit B1-58) The Moody's rating is considered to be more vulnerable to a downgrade due to weaker credit metrics, which, with further deterioration and a less predictable and supportive regulatory environment, could result in a drop to the Baa rating. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 59) This Baa rating could reduce the financial integrity of FEI by reducing its ability to maintain credit and access capital on as reasonable terms as an A3 rating.

The Commission determined in the 2009 Decision that Moody's rating should be the focus of attention because it was the lower in the group, and that the Moody's A3 rating should be maintained with a margin of cushion to ensure the financial integrity of FEI. (2009 Decision, p. 15)

None of the interveners took the position that FEI's 'A' rating should be jeopardized. AMPC/CEC submit that a reduction of the ROE to 7.5 percent at the existing 40 percent equity ratio would still leave FEI with strong credit metrics, including a cash flow coverage ratio of 2.67, and that a combined ROE reduction to 7.5 percent and lower equity ratio to 35 percent would leave FEI with a 2.35 ratio, which would still be above Moody's stated threshold of 2.3 to maintain the A3 rating. (AMPC/CEC Final Submission, pp. 35-36)

FBCU state that their current credit metrics are already weak for the existing rating and that the combined reduction in ROE and equity ratio as suggested by AMPC/CEC would not allow it to have a margin of comfort. (FBCU Final Submission, p. 15) FBCU also state that Moody's assessment of regulatory support had already weakened because of BC provincial energy policy. (T3:366) FBCU further state that under the Trust Indenture, Dr. Booth's recommendation would result in a coverage ratio of approximately 1.97. (FBCU Final Submission, p. 77)

Ms. McShane noted that the importance of 'A' category credit ratings arises from two factors: market access and cost. With respect to market access, Ms. McShane testified that regulated issuers can at times be closed out of the market if they have less than an 'A' category rating. Ms McShane further testified that "during the period June 2008 to January 2009, there was not a single issuer without at least one "A" credit rating who was able to issue long term debt <u>on any terms</u> in the Canadian market." With respect to cost, Ms. McShane states that in addition to market access issues, a rating downgrade would result in a cost increase to additional debt the company needs to raise. Further, it will also affect all of the utilities' outstanding debt as the increased cost of new debt will increase the required yield on existing debt and reduce the value of that debt. This higher cost of debt to the utility results in a higher cost of debt for ratepayers.
Ms. McShane further submits that institutional investors continue to have limits upon the amount of 'sub A' category debt they are able to hold or are restricted from holding Baa/BBB debt at all. This underscores the importance of 'A' credit ratings given the relatively small size of the Canadian market for Baa/BBB debt. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 35-37)

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36**)**

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

4.6 Other Jurisdictions

There is general agreement among the parties that the major natural gas utilities in Canada should serve as comparables for FEI for the purposes of assessing FEI's capital structure. This group which includes ATCO Gas, Union Gas, Enbridge Gas Distribution and Gaz Metro was used extensively throughout the proceeding as comparators. Dr. Booth also identified Nova Scotia Power Inc. as a reasonable comparator, being a province-wide integrated electric utility.

The equity thickness ratios of the comparator group of utilities are listed below in Figure 5. The equity ratios of the Canadian comparator group range from 36 percent to 39 percent in contrast to Dr. Booth's recommended equity ratio of 35 percent and FEI's current equity ratio of 40 percent:

Figure 5: Canadian Comparative Utility Equity Ratios

Company	Equity Ratio (%)
FEI	40.00
Dr. Booth on FEI	35.00
ATCO	39.00
Union Gas	36.00
Enbridge Gas Distribution	36.00
Gaz Métro *(*Quebec)*	38.50

(Source: FBCU Final Submission, p. 78)

While there is common agreement as to comparable gas utilities, there is considerable disagreement among the parties as to what these comparables suggest about FEI's required common equity ratio. (FBCU Final Submission, p. 78)

4.6.1 FEI Risk Level Relative to Alberta and Ontario Utilities

FBCU submit that the Commission should find that FEI faces higher long-term risk than natural gas distribution utilities in Alberta and Ontario for the following reasons:

- Alberta and Ontario marketplaces are more favourable from the perspective of supply and infrastructure for natural gas, overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the regions, and overall gas flows;
- Electricity costs in Alberta and Ontario are not heavily influenced by low embedded costs of "heritage hydroelectricity;"
- Eastern based utilities, by virtue of their proximity to the Marcellus Formation, have seen greater benefits from shale gas than FEI;
- The growing prevalence of multi-family dwellings in BC. The FBCU note that in a hearing before the Alberta Utilities Commission in 2011, Dr. Booth described this "condification" as a "significant competitive pressure;" and
- Government policy and legislation is a long-term risk factor for FEI. Among the provinces, BC is at the forefront of GHG reduction initiatives.

  (FBCU Final Submission, pp. 77-81)

FBCU point out that regardless of the analysis relied upon by Dr. Booth, his approach ended up recommending a 35 percent common equity ratio for all Canadian Utilities excepting Gaz Metro. (Exhibit C6-12, AMPC/CEC Evidence, Dr. Booth Evidence, p. 43) In this instance, FBCU had the following concerns with the analysis leading to his recommendation of 35 percent:

- Absent from the comparison was ATCO Gas which was the highest comparator at a 39 percent common equity ratio. FBCU notes that Dr. Booth puts ATCO Gas in the same risk category as FEI and perhaps a little riskier.
- There was no reference to Gaz Metro's deemed preferred shares in his portraying them as having a common equity ratio of 38.5 percent. This effectively understated Gaz Metro's effective deemed common equity ratio.

  (FBCU Final Submission, pp. 77-82)

AMPC/CEC submit that all of the comparators have common equity ratios that are below the current 40 percent common equity ratio of FEI. They also concede that at 38.5 percent, Gaz Metro is at the top of the range. However, they submit that Gaz Metro is in a far more difficult and risky climate than FEI, given FEI's advantage over electricity is 5 times as great as that of Gaz Metro. AMPC/CEC conclude that a common equity that is the same or greater than Gaz Metro's 38.5 percent would be unreasonable on comparative terms. (AMPC/CEC Final Submission, pp. 33-34)

FBCU submit that neither BCSPO nor AMPC/CEC made any attempt to reconcile the inconsistencies in the comparative analysis among Canadian utilities' capital structures. FBCU further submit that Dr. Booth's submission "that ATCO Gas risk was in the same risk bucket or slightly less risky than FEI" is significant because it suggests that the 40 percent common equity ratio for FEI is justified as ATCO has a 39 percent common equity ratio. (FBCU Reply, pp. 24-25)

Commission Determination

The Commission Panel has previously considered this matter in Section 3.2. The Panel has considered the common equity ratio decisions of other Canadian jurisdictions. **However, because each province is different in terms of its levels of regulatory protection and each utility has its own set of unique circumstances which are only minimally covered in the record of this proceeding, the Commission Panel has determined that only limited weight is to be given to the outcomes of proceedings in other Canadian jurisdictions.** Accordingly, evidence related to the equity ratios of other jurisdictions is used as a reference point only in determining whether FEI's is in an appropriate range.

4.7 Capital Structure – Commission Determination

The Commission Panel has determined that a common equity ratio of 38.5 percent is appropriate for FEI effective January 1, 2013.

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009.

The Commission Panel notes that the 2009 Decision put considerable emphasis on the uncertainty created by climate change legislation that did not exist during the previous cost of capital proceeding. In addition, the 2009 Decision acknowledged the change in the competitive position of

natural gas versus electricity but concluded that there were too many variables at play for this to be considered permanent. The Panel's finding that there is lower long-term risk related to both of these factors since 2009 is indicative of a reduction in overall risk to FEI which needs to be reflected in the common equity ratio.

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

Considering the discussion of optimal capital structure in Section 4.3, the Commission Panel notes that the reduction in common equity ratio to 38.5 percent is reflective of reduced long-term risk and yet balances this against potential disruption caused by a significant weakening of credit metrics.

With respect to credit ratings and metrics, the Commission Panel notes that considerable concern has been raised concerning FEI's credit metrics. In Section 4.4 we found the evidence supportive of maintaining an "A" category credit rating but not at all costs.

The Commission Panel notes that the 38.5 percent equity ratio awarded FBCU in this proceeding falls within the upper end of a range of comparative utilities in other Canadian jurisdictions and considers it to be reasonable on a comparative basis.

FEI is to file within 30 days of this Decision and the accompanying Order G-75-13 a document setting out how and when it will implement the change to its capital structure.

5.0 RETURN ON EQUITY

5.1 Key Issues

The Commission Panel is of the view that an important consideration in this proceeding is the determination of a return that provides investors with the opportunity cost of their investments. The Brattle Report recognizes and elaborates on this fundamental principle:

> "[The cost of capital is] Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk,* it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: . . ." (Exhibit A2-3, pp. 2-3)

However, even if one accepts the concept of the opportunity cost as a foundation of a Return on Equity determination, a remaining challenge is that risk and expected return of the relevant 'alternative investments of equivalent risk' are in the eyes of investors who have access to well functioning capital markets. These expectations are not directly observable to Panel members or to parties in this proceeding who provide evidence for the Panel to consider. Instead, estimates of investors' expectations are based on data that are interpreted through *models* of competitive capital markets. The Panel finds an observation offered in the Brattle Report to be instructive:

> "It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured." (Exhibit A2-3, pp. 3, 5-6)

The evidence presented to the Panel was based on a large variety of specific models that fall into four broad classes: (i) DCF models; (ii) CAPM (iii) ERP models and (iv) CE models. Within these four classes are numerous specific implementations that vary in structure, assumptions, and the data from which they were estimated. For instance, there are multiple DCF models with multiple estimates of the appropriate opportunity cost of an equity investment in the Benchmark Utility FEI. The estimates of the investor's opportunity cost of equity, summarized in Appendix F to this Decision, range from 6.15 percent (Dr. Safir CAPM) to 11.50 percent (Dr. Vander Weide's FRP model.

The models and approaches used by the expert witnesses in this proceeding to estimate the ROE are summarized in Tables included in Appendix F of this Decision.

The key issue then in the determination of the appropriate ROE is assessing how much weight to give to each of these models and their estimates. In turn, the weight given to each estimate depends on a judgment of the validity of the conceptual base of the four broad model classes and a judgment of how reasonable the model inputs are. The Panel has based this judgment, as much as possible, on the objective of determining the opportunity cost of equity.

The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE. As discussed in Sections 5.4 and 5.5, the ERP models (with the exception of Ms. McShane's CAPM based equity risk premium) and comparable earnings model are not based on compelling foundations. Furthermore, model inputs and estimates are largely *ad hoc* and assessments of the validity of these inputs and estimates are based on subjective evaluations with minimal logical guidance. Consequently, both the ERP and CE approaches are given no weight in the Panel's determination of the appropriate ROE for the benchmark utility.

5.2 The Capital Asset Pricing Model

The CAPM is based on consideration of individual investors making portfolio decisions in a well functioning capital market. As such, it is a model of the shareholders who own the shares of the firm. Of all the models used to present evidence to the Panel, we consider that the CAPM provides the underpinnings of investor choice in greatest detail.

The CAPM is based on portfolio theory, a theory that answers the question: If an investor wishes to achieve a particular rate of return and is able to invest in a large set of securities, what investment strategy will deliver the target expected return at lowest possible risk? (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 78) The somewhat surprising answer given by portfolio theory is that all investors will hold a combination of two mutual funds; one made up of all risky securities available, referred to as 'the market portfolio' and the second made up of risk free securities. In contrast to intuition, individual risk aversion will not determine which specific securities to invest in but will

determine how much of an investor's wealth will go in the market portfolio and how much will go into risk-free securities. A more risk-averse individual will hold less of their wealth in the market portfolio and more in treasury bills than a less risk-averse individual.

The result that investors will hold well diversified portfolios instead of individual stocks provides great guidance in elaborating on the seminal Supreme Court of Canada decision of *Northwestern Utilities* that the allowed return on capital is to be comparable to the return that would be earned on "... the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (Exhibit A2-3, p. 2) The CAPM tells us that these 'other securities' are not other comparable firms but are instead comparable portfolios that combine the market and the risk free rate.

The Commission Panel notes that the reason investors are better off holding a mutual fund instead of picking individual stocks is diversification. Diversification builds on another bit of intuition: don't put all your eggs in one basket. As The Brattle Report states:

> "…when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities. Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk." (Exhibit A2-3, pp. 6-7)

Since diversification is a driving force in investor's decisions, leading them to hold broadly diversified portfolios, when they consider the value of an individual stock they do not consider the total risk of the stock in isolation. They instead consider the amount of risk the stock will add to the risk of the mutual fund, recognizing the effect the stock has on the total diversification achieved. The amount of risk that remains after the benefits of diversification is referred to as non-diversifiable or systematic risk. The measure of the systematic risk is called beta. (Exhibit A2-3, pp. 6-7; Exhibit C4-9, p. 9; Exhibit B1-9-6, Appendix F, p. 88)

The CAPM builds on portfolio theory by providing a risk return relationship that recognizes beta as the risk measure. The theoretical foundation and the formulation of the CAPM is discussed in the evidence of Dr. Safir (Exhibit C4-9, pp. 8-11) and in the Brattle Report, which states:

> "The presence of a market underlies the "opportunity cost" interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, "comparable risk," investment B obtainable through the market." (Exhibit A2-3, p. 6)

The opportunity cost of an investment is based on the return on a risk free investment, which is the risk free rate. To this is added a 'risk premium'. In turn there are two parts to the risk premium. The first is the extra return that would be earned by holding the market portfolio on its own instead of the risk free security. The expected return on the market is denoted r_m and the risk premium over the risk free return, r_f, is denoted by (r_m - r_f). This is referred to as the 'the market price of risk' or the 'market risk premium'. The second component of the risk adjustment is beta which adjusts the market risk premium to account for the degree to which the individual stock contributes to the market risk; low beta stocks contribute less than average and earn less than the market rate, high beta stocks earn more.

The advantage of the CAPM is that it distils the complex interactions among risk averse investors trading with each other to a simple equation with three parts:

$$r_e = r_f + (r_m - r_f)\beta$$

where r_e is the opportunity cost of equity.

So, to estimate the investor's opportunity cost requires an estimate of the risk free return, the market risk premium and the beta. In spite of the CAPM's strong theoretical underpinnings, the estimation of these model inputs presents challenges as outlined in the Brattle Report (Exhibit A2-6, pp. 16-25) and in the evidence of Ms. McShane. (Exhibit B1-9-6, Appendix F, pp. 67-70) The challenges include the role to be played by the US data in the analysis.

The Panel recognizes the growing importance of US and indeed global securities in the portfolios of Canadian investors as pointed out in the evidence of Mr. Engen and of Ms. McShane. (Exhibit B1-9-6, Appendix E, pp. 11, 43-50; Appendix F, pp. A-14, A-15) The Panel also recognizes that none of the evidence was based on data related to global portfolios held by investors; for instance, market portfolios were defined as either the Canadian or US market separately and none of the evidence dealt with an integrated global portfolio. Furthermore, currency risk was not considered nor was the magnitude of foreign ownership of FEI. The evidence presented includes CAPM estimates on either US or Canadian data. In light of these concerns with respect to the lack of a complete global

perspective and the potential for risk (including currency risk), the Panel concludes that the more appropriate of these two perspectives is that of the Canadian based CAPM. Therefore, the Panel places greater weight on Canadian based CAPM estimates.

The Panel received a great deal of evidence on various estimates of the following three inputs.

(1) The Risk Free Rate, r_f

Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, all of the experts submit that the appropriate opportunity cost is better measured by the *forecasted* yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted.

Estimates of the risk free return available to investors, based on forecasted long-term Government of Canada Bond Yields, range from a low of 2.95 percent estimated by Dr. Vander Weide (Exhibit B1-9-6, Vander Weide Evidence Appendix G, p. 35) to a high of 4.0 percent by Ms. McShane and Dr. Safir. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 77; Exhibit C4-11, BCUC 1.4.1) Dr. Booth submitted that 3.0 percent was the forecasted yield on long-term Government of Canada Bonds but he considers forecast long Canada bond yields of 3.0 percent to be "well below any 'equilibrium' yield since they are only 1% above the forecast inflation rate and mean locking in a negative real yield for a typical taxable investor." (Exhibit C6-12, p. 60) Dr. Booth testified in cross-examination that:

> "…we do have foreign official flows of money coming into Canada because we are a triple A rate country and they are basically buying Canadian government bonds, pushing up prices, pushing down yields, and pushing them down to a value that I do not think reflects the proper trade-off between risk and return by "an ordinary private investor" making these decisions." (T8:1516)

Accordingly, Dr. Booth adds 0.8 percent to the 3 percent to recognize the alternative, and to arrive at his "Base adjusted LTC forecast" of 3.8 percent. (Exhibit C6-12, pp. 84-85, 93; Exhibit C6-15, BCUC 1.30.3)

In summary, the evidence presented seems consistent in stating that the current rates available on risk free government securities is between 2.6 percent and 3 percent. However, the Panel also agrees with the experts that current monetary policy is historically unusual and subsequently results in the possibility of a higher effective risk free rate. **Therefore, the Panel determines that the estimate of 3.8 percent for the risk free rate is reasonable, corresponds to Dr. Booth's estimate, and is within the relatively narrow range of estimates presented by all experts.**

(2) Market Risk Premium (r_m - r_f)

Estimates of the market risk premium range from 5 percent to 6 percent according to Dr. Booth (Exhibit C6-12, Appendix B, p. 16) to a high of 7.5 percent submitted by Ms. McShane. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 98) The basic estimation methodologies used by all experts were similar in that they were based on historical data on market returns and returns on risk free securities. They differ in some important details.

Ms. McShane bases her estimate on the average return on an investment in the market and shows, in Table 10, page 80 of her evidence that the average return on equities in Canada over the 1924-2011 period is 11.4 percent. From this number, Ms. McShane subtracts the *current* forecasted long-term Government of Canada Bond yield of 4 percent to arrive at her 7.5 percent estimate of the risk premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 87) The Commission Panel understands that it is typical to base the risk premium on the average historical difference between the return on the market and the risk free rate. It is our understanding that this approach is to deal with, among other things, the fact that historical market returns and historical bond yields reflect historical inflation while current returns reflect current inflationary expectations. This is an especially important consideration in the current environment where inflationary expectations are at a historically low level. (T3:483-485; T5:713-715)

To illustrate our concern with the approach used by Ms. McShane, the Commission Panel notes that there are times in the last 30 years where this approach would have yielded a very small or even negative risk premium. For instance, Schedule 2 of Ms. McShane's evidence reports that the yield on Long-term Canadian Government bonds in 1990 was 10.69 percent. If this was subtracted from the average market return it would have yielded an unreasonably low market premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, Schedule 2, p. 1; T8:716-717)

Ms. McShane was asked if she could provide a single reference to a textbook or Journal article that advocated using her approach. Her response was that she 'probably could not' (T5:717-718). Accordingly, the Panel gives no weight to the risk premium estimate of 7.5 percent provided by Ms. McShane.

Dr. Booth provides evidence that the historical risk premium is between 5 percent and 6 percent. He adjusts this range for 'Operation Twist' to obtain a risk premium estimate of 5.8 percent to 6.8 percent with a midpoint of 6.3 percent. (Exhibit C6-12, p. 93) Operation Twist refers to monetary policy intended to influence returns at various maturities including long maturities.

Dr. Booth provides two tests of the robustness of his estimate. One robustness test is to compare his estimate of the market risk premium with expectations used by FEI in assessing its defined benefit pension liability. Dr. Booth takes the expectation of market return of 7 percent, provided by FEI's consultants, and converts this geometric return to an arithmetic return. From this, Dr. Booth infers that FEI has, for purposes of valuing its pension liability, accepted an expected market return of 9 percent. Based on this he concludes, on page 93 of his evidence, that "[a]s a result, FEI's data seems consistent with a market risk premium of about 6.2%." In their Final Submission, FBCU submit that the Panel should not rely on data used in assessing pension liabilities. FBCU assert that, since actuaries provided the data, they naturally reflect a conservative bias. FBCU cited its witness Ms. McShane, who stated that pension fund managers and actuaries "... have absolutely no incentive to be anything but very conservative because they have a lot on the line. A pension fund needs to be able to assure that it has funds available to pay its retirees." (FBCU Final Submission, p. 151)

The Panel does not accept the assertion that the actuarial expectations are conservatively biased and should be rejected. Actuaries are charged with fairly assessing pension plan liabilities. The Panel finds, therefore, that this robustness test is indeed helpful in assessing the risk premium.

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent

market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent.

FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion. Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.

Other estimates of the risk premium were also in the range of 5.96 percent (Dr. Safir's Canadian estimate, Exhibit C4-9, p. 12, Table 1) to 6.6 percent. (Dr. Vander Weide's estimate, Exhibit B1-9-6, Appendix G, p. 38) **Given the preceding discussion, the Commission Panel accepts a market risk premium of 6.4 percent as it is within reasonable forecasts presented.**

(3) Betas

Evidence on the beta estimates is largely based on a standard approach of regressing returns from comparable firms on market returns. Since FEI does not have traded equity, estimates of beta must be based on comparable firms. In the evidence submitted, the set of comparable firms include Canadian firms as well as, in some cases, US-based firms.

Dr. Vander Weide submits a beta estimate of 0.92 based on the historical ratio of the average utility risk premium to the S&P risk premium. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 42) Aside from the fact that this is a beta estimate for US Utilities (T6:1092), the method differs significantly from the more commonly accepted method(s) of calculating a beta estimate as set out in the Brattle Report (Exhibit A2-3, pp. 15-16), and as calculated by the other witnesses in the proceeding. Accordingly, the Panel places no weight on this beta estimate.

The other beta estimates submitted range from a low of .36 by Dr. Safir for his Canadian CAPM estimate (Exhibit C4-9, pp. 12, 15), to a high of 0.65-0.70 by Ms. McShane. (Exhibit B1-9-6, pp. 97-98) Dr. Booth provides an intermediate estimate of 0.45-0.55. (Exhibit C6-12, Appendix C, p. 14) All

estimates begin with a regression of returns of the comparator firm on market returns with the 'raw beta' being the slope coefficient of the regression.

The differences among estimates largely result from adjustments that are made to the raw betas. Empirical evidence indicates that the regression based beta estimates seem to understate the betas of low risk firms and overstate the betas of high risk firms. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 96; Appendix A to Ms. McShane's Evidence, pp. A-21-26; Exhibit B1-9-6, Appendix G, p. 41) Since, by construction, the beta of the market is one, the adjustments are intended to bring the estimated beta's closer to one. To accomplish this, Ms. McShane contends that it is appropriate to adjust utility betas towards the market average of 1.0. (Exhibit B-19-6, McShane Evidence, Appendix F, p. 96) Both Dr. Booth and Dr. Safir, on the other hand, contend that the adjustment should be to the utility average beta that is in the range of 0.5 - 0.6. (Exhibit C6-12, Booth Evidence, p. 71; Exhibit C4-9, Safir Evidence, p. 15)

None of the evidence presented revealed the actual bias in beta estimates; instead the experts assert a particular adjustment. In cross-examination Ms. McShane acknowledges that utility betas may indeed not trend towards one.

Mr. HOBBS: And because regulation protects companies, isn't it also true that you would not expect betas for utilities to ever trend towards 1?

Ms. McSHANE: To trend towards 1. I guess I don't disagree with that. I never said that they would. (T4:549)

Similarly, in cross-examination at T6:1073, Dr. Vander Weide says*:*

DR. VANDER WEIDE: Yes. And I readily recognize that betas for utilities don't adjust toward 1.0.

In their Reply, FBCU argued:

> "Ms. McShane's relative risk adjustment of 0.65-0.70 for a benchmark utility, based partly on adjusted betas, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 55% of the risk premiums achieved on the equity market portfolio. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower)

> returns than the CAPM and beta would have predicted. It is not logical to conclude that, based on that experience, utility investors now only expect to achieve an equity risk premium that is 45% to 55% of the equity market risk premium (or Dr. Safir's lower 36%) simply because utility share price movements have not exhibited a high degree of correlation with price movements in the overall equity market." (FBCU Reply, p. 35)

An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.

5.2.1 Adjustments to the CAPM

A number of experts raised concerns about the validity of the simple 'single factor' CAPM. The term single factor refers to the reliance of the prediction of the model on only the market portfolio, the factor implied by the theory. Ms. Ahern introduced in evidence a summary article that shows how other factors such as firm market capitalization (size) and market-to-book ratios can provide added explanatory power to the single factor CAPM. (Exhibit B2-7, Evidence of Ms. Ahern, pp. 13-14; Exhibit B2-7, Attachment PMA-1, Exhibit PMA-9)

The CAPM is by far the most widely studied asset-pricing model and it is not surprising that more is known about its empirical performance than other asset pricing models. This evidence also implies that improved performance can be achieved by including these well-studied extensions of the model. The Panel notes, however, that none of the experts relied on the extensions as found in the literature findings in dealing with the shortcomings of the single factor CAPM. (Ms. McShane, T5:720-722); Dr. Vander Weide, T6:1102-1108; Dr. Safir, T7:1259-1262; Ms. Ahern, T7:1355-1357; Dr. Booth, T8:1658-1663) Instead, the evidence presented by different experts responded to the relatively poor empirical performance of the CAPM in a number of *ad hoc* ways.

Dr. Vander Weide's response to the weak empirical performance of the CAPM is to place no weight on CAPM estimates even though he provides estimates himself. In cross-examination, however, Dr. Vander Weide testified that he did not attempt any standard adjustments to the CAPM that might improve performance. For instance, he did not adjust for the importance of international markets to Canadians, he did not adjust for changes in capital structure and he did not study the ability of a

multi factor model to capture returns. (T6:1108-1111) As a result, the Panel does not accept Dr. Vander Weide's response to the relatively poor performance of the CAPM and continues to place weight on the model.

Ms. McShane and Dr. Booth both attempt to improve the performance of the CAPM by adding empirical analysis in order to augment the basic model. Dr. Booth is clearest in his objective when he states: "I regard this sort of adjustment as converting the CAPM into a conditional CAPM where the CAPM holds conditional upon the state of the financial markets." (Exhibit C6-12, p. 81)
Dr. Booth testified that an academic literature exists that supports the analysis of a conditional risk premium and his credit spread adjustment is consistent with that literature. (T8:1659)
Ms. McShane does not provide the same link to the academic literature and acknowledged, in cross-examination, that her work is along the lines of a multi factor CAPM. (T5:718-720)

The Commission Panel appreciates the efforts of the experts to recognize and deal with the shortcoming of the single factor CAPM. The evidence suggests there are two main thrusts to this effort: i) improving the estimate of the risk premium by conditioning on the current state of the capital markets; and ii) improving estimates of the risk return relationship by adding the factors to the single factor CAPM. Notwithstanding the efforts, the Commission Panel finds that we are not able to assess the validity of the extensions to the single factor CAPM that were presented as there is insufficient evidence involving the use of multi-factor models in this proceeding. The experts expressed reluctance to include other potential extensions to the CAPM that they thought were too complex. This is further addressed in Section 8.

In this regard, the Panel agrees more generally with the specific concern of ICG who argues that in Ms. McShane's CAPM based ERP, she "…makes an adjustment to the market risk premium of approximately 100-150 basis points because in her opinion market risk premium are in fact correlated with the risk free rate." ICG cites Dr. Safir as characterizing the adjustment as arbitrary and not in keeping with the CAPM model. ICG submits that before the Commission Panel accepts this adjustment there must be very strong evidence to support it. In the absence of such strong evidence, the CAPM specifications should not be changed. ICG goes on to say that: "The evidence regarding the correlation (inverse relationship) between the market risk premium and the risk free rate is in fact just that, it is a subjective judgement, with at best, very limited evidence in support of Ms. McShane's proposed departure from the CAPM model." (ICG Final Submission, p. 19)

In support of its argument that there is limited evidence in support of Ms. McShane's adjustment ICG submits that her evidence in support of a relationship between the market risk premium and the risk free rate is presented on a cumulative basis. It argues that when the same data is provided on a non-cumulative basis the US risk premiums do not follow income returns in the manner she suggests (Exhibit B1-53, Undertaking No. 14) and in some instances the data support the opposite conclusion to that observed by Ms. McShane.

Rather than relate the models presented in this hearing to the academic literature, as presented by Ms. Ahern for instance, the extensions seem to be somewhat *ad hoc* leading to the sort of concerns raised by ICG. There is no evidence, therefore that the models present were not the result of a "fishing expedition." That is, the Panel does not know if other adjustments or specifications would produce different results and we cannot assess whether other non-reported specifications should logically be ignored. In the absence of persuasive evidence that these are of value, the Panel is content to consider simple single factor models. At this time the Panel is not persuaded that the specific model extensions that are presented are valid and hence places no weight on them. However, the Panel recommends that in the future improvements in the model can also be brought into evidence, but the evidence should then include both the model extensions as well as a basis on which to judge the validity of the extensions.

5.2.2 CAPM Based Estimate of ROE

Summarizing the discussion above, the Commission Panel has applied the required judgment and accepts the CAPM estimate at 7.64 percent. This reflects a risk free rate of 3.8 percent, a risk premium of 6.4 percent, and a beta of 0.6.

5.3 Discounted Cash Flow Approach

The basis of the DCF approach is the principle that in a competitive market investors who purchase securities are essentially bidding for expected future cash flows that the security entitles them to. Competition implies that investors search for 'good deals', ones that offer the lowest price for a particular cash flow of a particular risk. The higher the price paid, the lower the expected return, so, in an attempt to improve their lot, investors search for securities that trade at a low price generating a high expected return. In their quest for high returns, they are willing to pay a price up to a level

that would make the purchase at least as good as the next best alternative, i.e. equal to their opportunity cost. Of course, in a competitive market, other investors are also looking for good deals and, as a result, competition ensures that observed prices generate returns equal to the opportunity cost.

The theory implies that if one can observe prices and expected cash flows one can infer the investor's opportunity cost. The DCF model applies this logic to equity investment in order to infer the opportunity cost of equity. It is assumed that cash flows to investors consist of dividends and that stock prices reflect investors' expected dividends and the opportunity cost of the investment. If we observe prices of equity and estimate all future dividends that the equity gives title to, then one can infer the opportunity cost of equity. (Exhibit A2-3, pp. 26-29; Exhibit B1-9-6, McShane Evidence, Appendix F, Appendix C, p. C-1)

An attractive feature of the DCF model is that it assumes, unlike the CAPM, that investors hold realistic investment horizons; both short and long-term investors estimate all dividends that the firm will provide over its lifetime. As with the CAPM, a significant disadvantage to the Commission is that for FEI none of the inputs, for example, price, dividends, or opportunity cost, are directly observable. The equity of the benchmark utility is held by Fortis Inc. and not actively traded. Therefore, future dividends are in the eye of the beholder as is the opportunity cost of capital. As a result, the opportunity cost estimate rests entirely on inferences that are commonly based on comparable firms. Not only should these firms be comparable, they should also have actively traded equity, and a source for estimating expected dividends.

Simplifying assumptions make the task of estimating dividends easier and the evidence submitted was all based on one of two simplifications or models. The 'Perpetual Constant Growth' model assumes that investors estimate the next dividend to be paid by the company and a single rate at which dividends will grow in perpetuity. The validity of the constant growth model is reduced when the estimated growth rate comes close to the opportunity cost (as this implies an extremely large stock price) and the model is invalid if the expected growth rate is greater than or equal to the opportunity cost of equity. The second model, 'the multi-stage growth' model, also requires an estimate of the next dividend to be paid but then allows investors to see multiple stages of constant growth; for example, the investor might expect growth of 4 percent for the next five years, 3 percent for the 5 years after that, followed by a constant perpetual growth rate of 2 percent starting

11 years hence. Although the long-term perpetual growth stage must meet the same growth restrictions as the constant growth model, the earlier stages are not restricted in this way. Therefore, multi stage growth models allow considerable more flexibility in dealing with growth forecasts. The Commission Panel has considered DCF-based ROE estimates presented by Ms. McShane, Dr. Vander Weide, and Dr. Safir.[6] Dr. Booth's DCF estimate for the market as a whole was used as a check on his CAPM estimate and is discussed with that estimate previously in Section 5.2.

1) Ms. McShane's estimates

Ms. McShane provides five different estimates with ROE estimates based on the DCF model. The estimates range from 8.6 percent to 11 percent. The estimates were variously based on 12 US Utilities or 5 Canadian utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 113) FBCU submit that: "The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%)." (FBCU Final Submission, pp. 105-107) The FBCU also point out that Ms. McShane relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations, minimizing the need to superimpose on the analysis her own subjective view of growth expectations. (FBCU Final Submission, p. 106) Ms. McShane recognizes, however, that the forecast period for analysts' long-range earnings and dividend forecasts is typically three to five years over a business cycle (Exhibit B1-9-6, Appendix F, Appendix C, p. C-4), and that extending these forecasts into perpetuity in the constant growth model can overstate expected return. (T4:664-665)

2) Dr. Vander Weide's estimates

Dr. Vander Weide only presents evidence based on a constant growth DCF and only for a sample of US Firms. He relies on I/B/E/S Thomson Reuters Mean Growth forecasts to estimate dividend growth. Dr. Vander Weide's application of the DCF model to his comprehensive group of utilities produced a result of 10.3 percent, and to his smaller group of utilities, 10.0 percent, including 0.50 percent for flotation costs. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, pp. 27-31; Exhibits

[6] Dr. Booth employed a Constant Growth model but only to estimate the market wide expected return. This was used as a check on his CAPM estimate and so is not included in this discussion.

6 and 7 of his evidence) The FBCU submit that "…Dr. Vander Weide's DCF estimates are reasonable and should be given significant weight." (FBCU Final Submission, p. 108)

3) Dr. Safir's estimates

Dr. Safir uses a two stage DCF model to develop two estimates; one of 8.99 percent based on 5 Canadian firms and one of 8.86 percent based on a sample of 18 US utilities, before adding flotation costs amounting to 5 percent of the initial ROE estimates. (Exhibit C4-9, pp. 24-26, and Schedules 3 and 4)

Commission Panel Discussion

The Brattle Report observes: "The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality." Elsewhere the report is more specific: "The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years." (Exhibit A2-3, p. 30)

The FBCU urges the Panel to give the DCF considerable weight, while the AMPC/CEC submits that "a DCF analysis can provide a helpful "check" on CAPM estimates, but the Commission should be cautious not to rely too heavily on it." (FBCU Final Submission, p. 89; AMPC/CEC Final Submission, p. 41)

The Commission Panel is of the view that, notwithstanding the concerns expressed about the approach, considerable weight should be given to the DCF but also accepts that caution should be used in assessing the growth estimates presented. A number of specific concerns arise with respect to the evidence presented:

a) **Reliance on analysts' short-term forecasts as the long run forecasts in constant growth formulas**:

This reliance appears in the single stage models presented by Ms. McShane and Dr. Vander Weide. For instance, Ms. McShane's estimate based on Canadian comparable firms assumes perpetual dividend growth of 7.5 percent. Since this is larger than her estimate for long run GDP growth of 4.3 percent, Ms. McShane seems to imply that FEI will grow to be an increasingly larger segment of the economy. This is inconsistent with the evidence presented in Appendix F of her testimony where she enumerates many reasons why consumers, both residential and commercial, will migrate from natural gas to other sources. Similarly, Dr. Vander Weide's estimates of the cost of capital use short-term analysts' forecasts to estimate the constant growth model. Similar to Ms. McShane, the resulting implication is that FEI will become a larger component of the economy over time, a conclusion that seems inconsistent with FEI's submissions regarding a shrinking market share and falling customer capture rates. (FBCU Final Submission, p. 53) We also note that Dr. Vander Weide included firms whose growth rate exceeded his estimate of the cost of equity in his comparable firms. As noted above, such a growth rate is inconsistent with the DCF constant growth model yet were included in his sample without adjustment. This calls into question the DCF estimates presented by Dr. Vander Weide.

The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.

b) **Reliance on comparable firms operating in the US**:

The AMPC/CEC submits that the use of US based comparable firms renders DCF estimates of limited value. In their submission, AMPC/CEC cites Dr. Booth as follows:

> "[In the past] we had lots of pure play utilities in Canada, where you could do a DCF. In particular, all the local telephone companies were still regulated by the CRTC on a rate of return rate based method, and we had Island Telephone traded, Maritime Tel traded, NewTel traded, Bruncor Traded, Bell Canada traded, B.C. Tel traded. So we had a lot of traded rate of return regulated utilities that we could actually do DCF tests on. Unfortunately, they don't exist anymore." (T8:1493-1494)

While the Commission Panel concurs with the concern about comparability of US based firms, it also agrees with the argument of FBCU that, given the paucity of comparable Canadian firms, also recognized by Dr. Booth, augmenting Canadian data with US firms is appropriate. (FBCU Final Submission, p. 94) The Panel also recognizes the need for careful informed judgment in adjusting the US based estimates to reflect differences in the respective environments.

c) **Analysts' forecast bias**:

Given the heavy reliance on the forecasts of equity analysts, the AMPC/CEC submit that analyst bias may inflate DCF ROE estimates. (AMPC/CEC Final Submission, p. 59) FBCU argues that analysts' forecasts for utilities are not biased. (FBCU Final Submission, p. 111) The Brattle Report notes that studies have shown that analysts' forecasts are likely to be more accurate in utilities than in other sectors and bias is likely to be less in utilities than other sectors. (Exhibit A2-3, pp. 28-29)

The Panel finds that there is reason to be cautious of potential analyst bias in the utility sector. The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made. The Panel expects that future hearings will be informed of the latest research on bias in the analyst's reports on the utility sector.

Overall Assessment

The Commission Panel finds that the constant growth DCF models presented have growth assumptions that render the estimates questionable given the discussion above. Therefore, we place little weight on the submitted estimates that are based on the constant growth DCF. The estimates that the Panel found most helpful are Ms. McShane's multi-stage estimates in the range of 8.6 percent to 9.2 percent and Dr. Safir's estimates of 8.86 percent to 8.99 percent (two-stage). (Appendix F) Applying the appropriate judgment required, **the Commission Panel accepts an 8.9 percent DCF based estimate of the opportunity cost of equity.**

5.4 Equity Risk Premium Models

5.4.1 Introduction

FBCU's witnesses Ms. McShane and Dr. Vander Weide each provided results from various models, classified as equity risk premium models. Ms. McShane provided the results of three different 'types' of ERP models, comprising numerous estimates. Dr. Vander Weide used two types of ERP models, which he termed "Ex-Ante" and "Ex-Post" risk premium tests, and used two different samples for each of the two types of tests. None of the other witnesses relied on the ERP.

The Brattle Report summarizes the form and some of the issues concerning ERP models. According to the report, the ERP is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. It notes that the historical risk premium is commonly estimated as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the sample period over which the estimate of the spread (i.e., the risk premium) is to be based. The Brattle Report states that it is important that the analysis is consistent in its choice of a debt instrument to determine the cost of debt and that used to determine the risk premium. It also notes that the realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. (Exhibit A2-3, p. 31)

The Brattle Report states that the forward-looking model requires that the analyst determine a proper measure of the cost of debt and how to estimate the expected risk premium. It says that because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural candidates for the expected bond cost. However, determining the expected equity return is more difficult and requires the reliance on an estimation technique. It notes that it is common to rely on DCF models to determine the risk premium in the forward-looking version of the model. (Exhibit A2-3, pp. 31-32)

5.4.2 Discussion of the ERP Method and Results

The Brattle Report states that the risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model, but that "…the Risk Premium Model

does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP." (Exhibit A2-3, p. 33) Moreover, there is a concern that the historical risk premium approach to the ERP assumes that a historically realized risk premium is an appropriate measure for expected returns, but that over any given period, especially short periods, realized returns can differ substantially from expected returns. (Exhibit A2-3, p. 31)

A strength of the model identified in the Brattle Report is that the information on which the model relies is auditable. However, it notes that because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. It further states that the implementation of the model largely determines its ability to capture the systematic risk of companies, noting that, unless a forecasted return for relevant companies is used, the model will be unable to estimate reliably the cost of capital across different economic conditions. (Exhibit A2-3, pp. 34)

Commission Determination

The purpose of a rate of return model is to provide structure to the discussion of 'what a fair rate of return is.' Models used to assess this question provide structure and clarity and, in turn, a basis for the data to consider the appropriate interpretation to give it and the estimates.

The lack of a strong theoretical footing for ERP, as noted in the Brattle Report, may explain the large number of ERP estimates submitted to the Panel and the potentially intractable discussion of the merits of the models. There is simply little to help focus the analysis and as a result many models can be submitted as 'true' even though there is little on which to judge the validity of the submission.

The large number of estimates along with the absence of a compelling framework raises the following reservations about the estimates and indeed about the entire approach:

1. The models combine elements of the CAPM and the DCF with other ad hoc adjustments. Since evidence was presented on both the CAPM and DCF, it is not clear what is added by looking at these alternatives.

2. While it is not clear what is gained through these ERP models, it is clear that clarity is lost. In particular, the assumptions used in various estimates are difficult to evaluate. Ms. McShane, for instance, uses return estimates based on a sample of US firms with the 30-year Canada Bond rate in some estimates of the risk premium but in others uses 30-year A-rated utility/government bond yield spreads. (Exhibit B1-9-6, Appendix F, p. 99) Similar ad hoc assumptions are also found in Dr. Vander Weide's analysis. For instance, AMPC/CEC point to Exhibit C6-21 to demonstrate that if bond returns rather than bond yields were used in the analysis, the average Ex-Post risk premium for utilities would be approximately 4.47 percent or 2.3 percent less than Dr. Vander Wiede's estimate. Consequently, the AMPC/CEC argues that the Ex-Post estimates of Dr. Vander Weide must be ignored or if not ignored, then reduced by 2.3 percent. However, FBCU state that it is appropriate to use bond yields as the true risk-free rate. It is not clear, however, why the risk free rate is not estimated using a risk free return.

   Again, while judgment is always needed to evaluate estimates, without a theoretical base, there is no consistent way in which these differences of opinion can be assessed.

3. Since the model variations are ad-hoc they are subject to the concern that they may be subject to a "fishing' expedition" criticism. In contrast, while we can obtain various results from the CAPM or DCF models by changing parameters such as the risk premium in the CAPM or the growth rate in the DCF, the reasonableness of the selected parameter can be questioned.

Given these concerns along with the fact that there is ample evidence on both CAPM and DCF based estimates, the Panel places no weight on the ERP estimates submitted.

5.5 Comparable Earnings Approach

The Brattle Report states notes that the CE method is one of the traditional approaches to the cost of capital estimation, but that it does not have a financial economics foundation or strong theoretical basis. The report states that the legal decision, *Federal Power Commission et al v. Hope Natural Gas Co.,*[7] which stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks, is often cited in the use of comparable earnings, but that neither the Canadian nor the US Supreme Courts has identified any specific methodology to determine a "fair return." (Exhibit A2-3, pp. 11, 36) The Commission Panel observes that much has been learned about financial economics since 1944. In particular, the notion of a comparable investment has been carefully cast in terms of investments in portfolios of

[7] 320 U.S. 591 (1944); 64 S. Ct. 281; 88 L.Ed. 333 (1944) U.S. Lexis 1204

comparable risk since portfolios are more efficient in achieving any expected return than is a single security.

The CE method requires the use of a sample of unregulated companies as comparators, since the use of regulated companies to estimate the comparable cost of capital would be circular. The Brattle Report notes that because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company, and because the estimates from the model do not come from regulated companies or activities, the method does not recognize the regulatory context in which the cost of capital is being applied. (Exhibit A2-3, pp. 35, 38)

The Brattle Report states that a major issue with the comparable earnings method is whether realized book returns are a good proxy for the return that investors expect going forward and notes that it is a backward looking measure with no consideration of current market conditions. (Exhibit A2-3, pp. 36-37)

Ms. McShane submits that the fair return standard "…is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard…." (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8) [emphasis in the original] In her view, the comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard and it is critical that the regulator recognize the comparable returns standard when setting a fair return. (Exhibit B1-9-6, Mc Shane Evidence, Appendix F, p. 114)

Ms. McShane submits that the comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Ms. McShane arrived at her comparable earnings estimates based on the earnings on book-value of 21 unregulated Canadian companies from 2004-2011. (Exhibit B1-9-6, Appendix F, pp. 113-116) She arrives at the following result: "To recognize the unregulated companies' higher risk, a

downward adjustment of 125 to 150 bps to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%." (Exhibit B1-9-6, Appendix F, p. 116)

To complete her comparable earnings estimate, she assesses the need for a market/book adjustment to the comparable earnings results. She submits that "[t]he similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios." (Exhibit B1-9-6, pp. 116-17)

Dr. Booth submits that the average ROE increases when one starts adding low-risk firms to a comparable earnings sample and then progressively decreases as more risky firms are added, particularly after the lowest risk firms are added. He argues that: "…to get a high ROE from a sample of comparable earnings firms simply means coming up with "reasonable" screens to narrow down the sample and exclude those firms with significant losses. (Exhibit C6-12, p. 6)

He used book-value based estimates for Corporate Canada as a whole, using Statistics Canada reported earnings for the period 1987 to 2011 and the TSX composite for the same time period. He arrived at a CE estimate for the Canadian market of 9.3 percent, and says that "Like the overall stock market return this then needs to be lowered for the lower risk attached to regulated utilities." (Exhibit C6-12, Appendix E, pp. 3, 7, Schedule 2)

Dr. Booth submits that CE "…is totally unreliable unless a market to book adjustment is made which is rarely the case." (Exhibit C6-15, BCUC 1.39.0) He also submits that a "…market to book adjustment is needed since low risk firms usually have market power which is reflected in higher ROEs. It is incorrect to then allocate to a utility an ROE from a sample of firms that reflects market power when regulation is designed to remove this market power." (Exhibit C6-15, BCUC 1.67.1)

Dr. Booth also says that a problem with looking at past ROEs is that they are earned on historic accounting book equity that does not reflect what can be earned on investments today. (Exhibit C6-12, Appendix E, p. 5)

The AMPC/CEC argues that the Commission should place little or no weight on the comparable earnings test. (AMPC/CEC Final Submission, pp. 38, 60)

Dr. Safir used two market-value based estimates: one for the same Canadian sample of 21 companies used by Ms. McShane; the other based on a sample of 31 US companies in the consumer goods, industrial goods or service sectors using the same sample selection criteria as Ms. McShane used for her Canadian sample. (Exhibit C4-9, pp. 28-29)

Dr. Safir calculated his comparable earnings estimates "…using net income and market value of equity…." He submits that because his comparable earnings estimates were calculated using market-based values instead of book value, they more accurately capture the conditions in the current capital markets in which the benchmark firm would be competing for capital. He goes on to say that his method accounts for factors such as inflation, since both the net income and the stock prices will reflect the level of inflation occurring at the time these numbers were reported and that "[b]ook value-based calculations of comparable earnings will not account for inflation." (Exhibit C4-9, p. 30) Using his market-value based method of calculating CE Dr. Safir arrived at estimates of 6.85 percent for his Canadian sample and 5.81 percent for his US sample. He submits that the Canadian estimate should be given twice the weight of his US estimate and arrives at a weighted average estimate of 6.50 percent. (Exhibit C4-9, p. 33)

Dr. Vander Weide did not provide a CE estimate.

Commission Determination

The fundamental issue regarding the CE test is its lack of a basis in financial economics. The approach requires a sample of unregulated companies of similar risk, but creating a sample of unregulated companies that are, and can be shown to be, of similar risk is difficult without a theoretical basis such as the CAPM or the DCF. Dr. Booth has pointed out the issues that arise when even 'reasonable' screens are used to eliminate companies from the entire universe of companies to create a sample. Moreover, the CE method is retrospective, whereas the ROE to be established for the benchmark utility is prospective.

In her evidence, Ms. McShane submits that: "The economic principle guiding the fair return is the opportunity cost principle." She also submits that one of the requirements of the FRS is that the return allowed is comparable to the returns of enterprises of similar risk and that it is critical that the regulator recognize the comparable returns standard when setting a fair return. She also states that the CE test is an implementation of the comparable returns standard and is to be distinguished from the cost of attracting capital standard. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 2, 8, 114)

During cross-examination a discussion on whether the comparable earnings test reflects an investor's opportunity cost concluded with the exchange below:

COMMISSIONER GIAMMARINO: But you would agree that in terms of an opportunity cost, it doesn't match up that closely to what we would consider the exact opportunity cost to the investor.

Ms. McSHANE: A: No, it is not an opportunity cost in the same sense that you were talking about. (T5:732-35)

The Commission Panel addressed the FRS in Section 2 and recognized that a fair or reasonable overall return on capital should be comparable to the return available from the application of the invested capital to other investments of like risk (comparable investment requirement). However, the Commission does not accept that this requirement means that it must use the comparable earnings method as a means of determining what return is required to meet the FRS. Modern finance theory has clearly established that comparable risk is assessed relative to a *portfolio* rather than a single stock. This is indeed the basis of the CAPM and other extensions of risk return modules. Searching for individual firms of comparable risk is consistent with this only if the comparison recognizes non-diversifiable risk as the relevant characteristic. This is exactly what is done when CAPM comparators are sought. But this is ignored when companies are considered comparable on dimensions other than systematic risk.

The preceding discussion highlights some of the serious problems the comparable earnings method contains as a means of determining the return required to meet the FRS. **Consequently, the Commission Panel places no weight on the comparable earnings results.**

5.6 Allowance for Financing Flexibility

Ms. McShane described financing flexibility allowance as intended to cover three distinct aspects: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle (Exhibit B1-9-6, McShane Evidence, Appendix F, p. F-1). Flotation costs and financing flexibility adjustments are typically applied to the market-based cost of equity estimates, i.e., the CAPM and the DCF models.

Ms. McShane provided an allowance of 50 basis points for each of her market based tests in order to maintain the market value at a small premium to the book value. In the alternative, should the Commission rely only on the market-based tests, Ms. McShane proposed an allowance for financing flexibility at 1.0 percent. (Exhibit B1-20, BCUC 75.2.1)

Dr. Vander Weide provided an allowance of 50 basis points for flotation and financing flexibility. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 35)

Dr. Booth provided an allowance of 50 basis points, stating that the market opportunity cost should be adjusted upwards to include issuing costs or a financial flexibility adjustment to make sure that shares can always be sold to net out the original cost included in the rate base, which is all that earns the fair ROE. He also noted that most regulators in Canada have allowed 50 basis points for these new issue costs (Exhibit C6-12, p. 8).

Dr. Safir referred to a survey of flotation costs, which determined them to be approximately 4.5 percent of the recommended rate of return. Based on the 4.5 percent, Dr. Safir applied 5 percent of the rate of return, an equivalent of around 32 to 40 basis points for his CAPM models and 47 bps for his DCF model, to reflect the marginally higher costs that would be faced by Canadian issuers either crossing the border to utilize the US market or in issuing in the smaller Canadian capital market. (Exhibit C4-9, pp. 16-18)

Commission Determination

The Commission Panel accepts the allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE. As indicated in Section 5.5, the two market-based tests, CAPM and DCF are given equal weight in the determination of the allowed ROE for the benchmark utility.

With reference to Ms. McShane's proposed additional 50 bps if the CE test is not accepted, the Commission Panel is of the view that each test to estimate the fair return is applied separately to provide a different perspective and each test's results are not contingent upon the results of other tests. Therefore, the Commission Panel does not accept the conditional 50 bps in Ms McShane's alternative proposal.

5.7 Fair Return on Equity – Commission Determination

The Panel finds that the DCF and CAPM should be given equal weight in determining the ROE. Moreover, the Panel finds that CE and other ERP models have insufficient merit to be accorded any weight in the determination of the fair ROE. Considering the CAPM based estimate of 7.64 percent and the DCF estimate of 8.9 percent, the Panel concludes that the ROE, before adjustment for financing flexibility, of 8.25 percent is an appropriate base as it falls in the midpoint range of the two estimates. When an allowance for financial flexibility of 0.5 percent is added, the resulting ROE is 8.75 percent, to be effective January 1, 2013, provided for by Order G-47-12 and confirmed in Order G-187-12. **The ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula discussed and adopted in Section 6.**

FEI is to file within 30 days of this Decision and accompanying Order G-75-13 amended rate schedules in accordance with paragraphs 1 and 2 of Order G-75-13 as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013. FEI shall inform all affected customers of the final rates by way of customers notice.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

6.1 Introduction

In 1994, the Commission determined that the Benchmark ROE was to be estimated annually by an Automatic Adjustment Mechanism (AAM).[8] This AAM was eliminated by Order G-158-09 issued concurrently with the 2009 Decision. In eliminating the AAM the Commission stated that: "... in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard." (2009 ROE Decision, p. 72)

One of the stated purposes of this proceeding was to review the possible return to an AAM for setting an ROE of the benchmark utility and examine potential AAM models. In this Section, the Commission determines that:

- Reinstituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings is appropriate.
- A two-variable model AAM is to be instituted to set the benchmark ROE on an annual basis commencing in the 2014 calendar year for a period of two years.
- Implementation of the model will be subject to the actual long Canada bond yield meeting or exceeding 3.8 percent.
- The new formula will initially utilize the ROE of 8.75 percent as determined in Section 5.7.

6.2 Should the Commission Re-institute an AAM?

In considering re-instituting an AAM, the Commission Panel reviewed proposed AAMs to determine whether they would meet the Fair Return Standard or whether, as FBCU submit: "The Fair Return Standard is best met in intervening years until the next comprehensive cost of capital reviews by holding the ROE constant." (FBCU Final Submission, p. 153) In addition, the Panel examined the status of AAMs in other Canadian regulatory jurisdictions.

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[8] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., -- Decision and Order G-35-94, June 10, 1994.

6.2.1 Status of AAMs in Other Canadian Jurisdictions

The Brattle Report surveyed the cost of capital practices in Canada including the formulas used to set the ROEs in Ontario and Quebec. (Exhibit A2-3, pp. 64, 72)

In the 2009 Decision, FBCU was directed to complete a study of AAM alternative formulas and report to the Commission. In compliance, FBCU filed the 2010 report, "A Review of Automatic Adjustment Mechanisms for Cost of Capital" prepared by Concentric Economic Advisers (Concentric). The 2010 Report provided an examination of the use of AAM formulas in other jurisdictions, contrasted these with alternatives and considered the merits of various approaches. While not recommending that a formula be adopted, Concentric identified attributes that should be considered if an AAM is adopted in the future. (Exhibit B1-9-6, Appendix I) In this proceeding, FBCU again engaged Concentric to provide an update of its analysis, which examined the use of ROE formulas in other jurisdictions. The update included the following observations with regard to Canadian jurisdictions:

- The Ontario Energy Board (OEB) continues to rely on its AAM which it modified in 2009. The modified formula is based on 50 percent of the change in forecast long-term Canada bond yields and 50 percent of the change in observed A-rated utility bond index over the 30-year Canada Bond yield.
- In Quebec the Régie de l'énergie (Régie) modified its previous formula in 2012 to incorporate 50 percent of the change in utility bond spreads in addition to the existing formula's 75 percent of change in government bond yields.
- In its December 2011 Decision, the AUC determined that the credit market remained volatile and therefore decided not to employ an AAM for 2012. The AUC indicated that it was not prepared to preclude a return to some form of formula-based AAM in future once the capital markets had stabilized.
- The Newfoundland and Labrador Board of Commissioners of Public Utilities, in June 2012, approved an 8.8 percent ROE (which was not set by formula) for Newfoundland Power stating that this was within a range of reasonable values. The Board did not disavow or abandon the formulaic approach for future rate proceedings.

Concentric has not changed its position on AAMs and stated that: "periodic rate hearings remain the only reliable method for the determination of utility ROE's." However, Concentric noted that Canadian regulators have recognized that a sole reliance on simple relationships to government bonds cannot be relied upon to estimate ROE. Concentric points out that both Ontario and Quebec have incorporated utility bond spreads in their formulas and notes that this mitigates one fatal

weakness of past AAMs. Concentric views the two variable methodology utilized by Ontario as an improvement with a remaining concern being the lack of a specific link to the cost of equity , other than that conveyed by bond yields. (Exhibit B1-9-6, Appendix I, Concentric Update Report, pp. 1-4, 11)

The Commission Panel notes that both the OEB and the Régie formulas are variations of the model proposed by Dr. Booth and are discussed further in Section 6.2.2 below.

It appears that there is some acceptance by utility regulators in Canada of an AAM formula based on a two-variable model that uses the long-term Canada bond rate as a proxy for a risk free rate and a change in utility bond spreads as a proxy for credit risk. There is, however, reluctance in some jurisdictions to institute an AAM given the volatility of Canadian capital markets in recent years.

6.2.2 Submissions by Parties

AMPC/CEC

AMPC/CEC submit that the Commission abandoned the AAM in 2009 because it did not provide a fair return citing the following passage from the 2009 Decision: "the recent flight to quality has driven down the yield on long-term Canada bond yields, while the cost of risk has been priced upwards." Therefore, AMPC/CEC submit that the question for the Commission is, "what formula will allow it to return to an AAM, while ensuring that the results are fair in light of the current financial conditions and the conditions FEI might encounter going forward." (AMPC/CEC Final Submission, p. 62)

AMPC/CEC support a return to an AAM based on its contribution to regulatory efficiency because an AAM reduces the frequency of periodic ROE reviews. They note that FBCU have suggested that 3-5 years is a reasonable gap between comprehensive ROE reviews. AMPC/CEC points out that if the Commission agrees with this, an AAM would likely allow the reviews to be closer to five years rather than three, resulting in considerable efficiency benefits. (AMPC/CEC Final Submission, pp. 62-63)

Dr. Booth states that "The key problem with 'old' ROE adjustment models was that they *only* linked the ROE to the forecast long Canada yield. As a result, during the financial crisis the ROE formula

indicated declining ROEs while at the same time the utility cost of debt was increasing. An enhanced ROE formula has to deal with this, which can be done by incorporating the credit market adjustment I have used in my direct ROE estimates." (Exhibit C6-12, pp. 97, 100)

Dr. Booth recommends "an ROE adjustment model where ROE adjusts by 75% of the forecast change in long Canada bond yields and 50% of the change in the credit spread. This would be subject to a minimum forecast long Canada bond yield of 3.80% … Similar models are in use by the Régie and OEB." (Exhibit C6-12, p. 3) Dr. Booth selects 3.80 percent as the "floor" stating that this "is the lowest rate consistent with a normal cyclical low." (Exhibit C6-12, pp. 97, 100)
AMPC/CEC argue that Dr. Booth's enhanced two variable ROE formula addresses the concern with the old ROE formula that during periods of financial crisis the allowed ROE and utility borrowing costs move in opposite directions. They argue that Dr. Booth's formula obviates FBCU's concern that the AAM won't work because of the current unusual business cycle. The proposed 3.8 percent floor acts like a fixed rate ROE until the long Canada bond yields return to normal, and it provides an adjustment mechanism for periods when conditions are more typical. (AMPC/CEC Final Submission, p. 64)

ICG

Dr. Safir believes that an AAM for a limited number of years is appropriate because "It is simply not economically efficient to revisit the entire ROE setting mechanism annually" and also states that "the AAM is administratively efficient, resulting in significant savings by avoiding costly, annual rate hearings." In Dr. Safir's view, AAMs that reference long-term bond rates, such as the one previously used by the BCUC, are good ways to account for near term influences that affect a fair ROE. (Exhibit C4-9, pp. 36-37)

ICG observes that during the interim years between periodic cost of capital proceedings an AAM formula is more likely to result in an ROE that meets the FRS than no formula. It submits that the Commission should establish an AAM similar to the one discontinued by the Commission in 2009 that referenced long-term bond rates with a three year effective period. It would differ from the previous Commission AAM in that it would use a five year average for the forecast long-term Canada bond yield. (Exhibit C4-9, pp. 36-38; ICG Final Submission, p. 32; T7:1187)

ICG concedes that a multiple factor model may be more likely to meet the FRS than a single factor model, but given that the single factor model has been tested over a long period, it has been recommended to the Commission. (ICG Final Submission, pp. 32-33)

BCPSO

BCPSO submits that an AAM is beneficial because it ensures that the benchmark utility will not operate for more than a brief period of time with a higher than required ROE and therefore supports reinstatement of an AAM. (BCPSO Final Submission, pp. 19-20)

FBCU

FBCU does not support the return to an AAM. FBCU's main concern with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. They submit that an AAM relies on a formula with a limited number of inputs that could never capture the complex factors affecting ROE, and that an AAM likely relies on long Canada bond yields and corporate spreads, which are still affected by atypical market conditions. In addition, any formula relies on imperfect proxies. In their view, the application of the FRS requires a significant degree of analysis, market information, and judgment that evolve over time. Formula parameters are static and based on historic relationships and fundamental relationships may shift, leaving the formula out of touch with current market conditions. FBCU take the position that there is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one. This is supported by Ms. McShane who submits that the Commission should continue to address the appropriate cost [of capital] on a case-by-case basis: "There is no 'one size fits all' cost that should be determined by means of an interest automatic adjustment mechanism." (FBCU Final Submission, p. 153-156; Exhibit B1-9-6, p. 33; Exhibit B1-9-6, McShane Evidence, Appendix F, p. 7)

FBCU prefer to have the allowed ROE and capital structure set through a traditional process and remain constant between the periodic (three to five year) formal reviews, subject to events occurring that bring the results out of alignment with the FRS, which could result in an unscheduled full review process. This is preferable to having updates made on a basis that the FBCU believe is suspect. (Exhibit B1-20, BCUC 2.113.1)

FBCU argue that there is no efficiency gain associated with implementing the AAM, if there are to be periodic reviews. FBCU further argue that the regulatory burden associated with periodic cost of capital reviews is the same as that associated with periodic reviews with annual formula-driven ROE changes in the interim. FBCU also argue the FRS is best met in the intervening years until the next comprehensive cost of capital reviews by holding the ROE constant. (FBCU Final Submission, pp. 153-156)

FBCU further submit that "The rationale for why the Commission discontinued the AAM remains valid today. Meeting the Fair Return Standard is not optional." FBCU state that "All of the experts agree that we are still experiencing unusually low interest rates, and the ability of any AAM to produce fair results is far from certain [when such conditions exist]." (FBCU Final Submission, p. 153)

With respect to the positions taken by Dr. Safir and Dr. Booth, FBCU make the following submissions:

1. FBCU submit that Dr. Safir is proposing to return to an AAM that has already been rejected by the Commission, with the only difference being the starting point for measurement of changes in the forecasted long Canada bond yields (i.e., the use of the five-year average forecast). They cite Ms. McShane's statement that there is an inverse relationship between long-term government bond yields and the utility risk premium. FBCU also argue that Dr. Safir's use of a five-year average forecast Canada bond yield as the base line in the formula is problematic because it suppresses ROEs despite increases in long Canada bond yields. FBCU submit that while this five year average is intended to compensate for present unusually low interest rates, it would be better to postpone consideration of a formula, rather than implement a "quick fix" that artificially suppresses the ROE. (FBCU Final Submission, pp. 159-160)

2. FBCU submit that the AAM proposed by Dr. Booth is biased downwards. FBCU notes that the current long Canada bond yield is well below the 3.8 percent that Dr. Booth employs as the floor, and points out that while he expects rates to increase, he does not expect the forecast to rise above the 3.8 percent for at least three years. FBCU submit that the combination of rock-bottom forecast yields and a slow rise in interest rates has two implications. First, rock-bottom interest rates means that further declines are not likely. Second, any increase in the forecast long Canada bond rate will not result in an increased ROE. In addition, FBCU submit that the cross-examination of Dr. Booth indicates that he expects credit spreads to fall while the long term Canada bond yield remains below 3.8

percent, an expectation shared by Mr. Coyne. FBCU propose that the result of this will be a progressively lower benchmark ROE after 2013 if Dr. Booth's formula is employed. (FBCU Final Submission, pp. 160-161)

FBCU's position is that if the Commission requires an ROE AAM, it should seek to rectify the problems of the old formula. A new formula would address changes in the equity risk premium, and not solely changes in long Canada bond yields. Any adjustment factor would need to reflect sensitivity to change in bond yields to ROE. (Exhibit B1-9-6, pp. 27-29)

Corix

Corix submits that there is a continued flight to quality and a still increasing cost of risk, so an updated AAM is not appropriate at this time. (Exhibit B2-9, BCUC 1.2.1, p. 3)

6.3 Commission Determinations

6.3.1 Re-instituting an AAM

The Commission Panel does not take issue with FBCU's argument that an AAM formula with limited inputs cannot capture all of the complex factors affecting ROE and therefore, relies on imperfect proxies. However, at the same time, the Panel is of the opinion that the issue is whether the adoption of an AAM formula is better than the alternative, which is to do nothing as suggested by FBCU and Corix. In other words, while implementing an AAM formula may not be perfect, the question is whether it better satisfies the FRS than leaving the ROE static for a period of time or conducting frequent costly and time consuming ROE proceedings. The difficulty with leaving the ROE static over a three year or longer period is that financial markets continue to change and investors' needs continue to evolve. Therefore, in the view of the Commission Panel, implementing a mechanism to capture the impact of some of these changes is far superior to the alternative of doing nothing. Furthermore, as the AMPC/CEC submits, "if there are reasonable grounds to believe the mechanism is not producing fair results, the benchmark utility always has the option of asking for a review." (AMPC/CEC Final Submission, p. 64)

The Commission Panel does not disagree with FBCU's argument that the regulatory burden associated with periodic cost of capital reviews with or without an AAM is similar. However, we are

of the view that the likelihood of a requirement for more frequent ROE proceedings is reduced by having in place an AAM formula. Thus, the Panel is persuaded that the application of the AAM has the potential to contribute to regulatory efficiency.

Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the standard than taking no consideration of changes in the market over a three year period as suggested by FBCU. The AAM formula to be adopted and the timing of its use is addressed in Section 6.3.2.

6.3.2 Optional AAMs to be Considered

The Commission Panel acknowledges that interest rates have been atypical in recent years and have remained at historical lows. The historical AAM used by the Commission prior to 2009 relied exclusively on a single variable formula based on the long-term Canada bond yields as a proxy for risk free rates. This model was less than fully effective for utilities because the flight to quality kept interest rates abnormally low while the risk had been priced upwards. It could not assure that the FRS could be met in extended times of low interest rates.

As noted previously, Dr. Booth proposed a two-variable model that incorporates the traditional concept of tying the benchmark utility's ROE to the "risk free" long-term Canada bond yield, and also incorporates a credit market adjustment to reflect the relationship of ROE and credit risk within the utility sector. His model also utilizes a "floor" long-term Canada bond rate of 3.8 percent as the risk free proxy until such time as long-term Canada bond yields return to a more common level.

Concentric submits that any new AAM formula should address changes in the utility risk premium and not be based solely on changes to the long Canada bond yields. While it does not recommend a formulaic approach, it does provide several potential formulaic methodologies that could be used in British Columbia (Exhibit B1-9-6, Appendix I, 2010 Report, pp. 39-45)

In summary, possible options for re-instituting an AAM include:

- The single variable model used by the Commission prior to 2009 that was based on long Canada bond yields;
- The variety of approaches offered by Concentric (Exhibit B1-9-6, Appendix I, p. 11);
- Dr. Booth's two-variable model or a variation incorporating the long Canada bond yield, a floor level of long Canada bond yield to address the atypical low interest rates, and a metric to address credit spreads.

The Commission Panel recognizes the shortcoming of the single variable model used by the Commission prior to 2009 in that it fails to satisfy the FRS when interest rates continue at abnormally low levels. Accordingly, this model will not be considered.

While Concentric has explored a number of alternative formulas that could be used in British Columbia, the Commission Panel notes that none of these have been recommended by Concentric nor have they provided evidence as to their use and effectiveness in other jurisdictions. In addition, none of the interveners has expressed support for any of these. Given this lack of support and the lack of evidence to support their efficacy and relevance to British Columbia, the Commission Panel does not endorse any of the possible alternative AAMs explored by Concentric.

During cross-examination, Commission counsel asked Mr. Coyne of Concentric what advice he would give the Commission in terms of adjustments if the Commission were adopt an AAM similar to that of the OEB and the Régie. Mr. Coyne testified that a coefficient of 0.5 was a more accurate reflection of the historic relationship to long-term Canada bonds than 0.75. (T5:827)

Dr. Booth testified that he recommended 75 bps but that he could live with 50 bps and he did not believe that there would be a big impact. (T8:1622)

The Commission Panel is persuaded that a two-variable model similar to that proposed by Dr. Booth and currently utilized in Ontario is appropriate for application to the benchmark utility within British Columbia. (Exhibit C6-15, BCUC 1.44.5 attachment)

By utilizing the 50 percent adjustment of the change in the long-term Canada bond yield as a proxy

for risk free rates, it recognizes the relationship between ROE and risk while moderating the level of change resulting from any volatility in the long-term Canada bond rate. In addition, by utilizing the 50 percent adjustment in the change in the utility bond spreads, it recognizes the relationship between credit risk and ROE in the utility sector and moderates volatility in utility bond spreads. And finally, by utilizing a 3.8 percent floor for the long Canada bond yield, it recognizes the atypical relationship between ROE and cost of risk in periods of unusually low interest rates. Further, the application of similar models within both Ontario and Quebec supports it usefulness and acceptance within other Canadian regulatory jurisdictions.

Given the advantages, the Commission Panel adopts a two variable model AAM to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. The AAM formula will operate until December 31, 2015. The implementation of the model is subject to conditions outlined in Section 6.3.3. The formula will initially utilize the 8.75 percent ROE as determined in Section 5.7 as the base ROE.

The formula to be used and the basic method to determine the changes in long Canada bond forecast and the changes in utility bond spread are provided as follows:

$$ROE_1 = \text{Base ROE (8.75\%)} + 0.50 \times (LCBF_t - \text{BaseLCBF}) + 0.50 \times (\text{UtilBondSpread}_t - \text{BaseUtilBondSpread})$$

Where:

$LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.

UtilBondSpread_t is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

6.3.3 Impact of a 3.8 percent Floor

FBCU has argued that the AAM proposed by Dr. Booth is biased downwards. The Commission Panel agrees that the potential for a downward bias does exist.

Dr. Booth has recommended that any change in the ROE be subject to a minimum forecast bond

yield of 3.8 percent as this is the lowest rate which is consistent with a normal cyclical low. The Commission Panel accepts this as reasonable since it is the risk free rate for the CAPM ROE as determined in Section 5.2.

With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. **To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.**

The Commission Panel has considered Concentric's submission that Dr. Booth did not specify an objective bond forecast to reference as a starting point. We are of the view that the potential for downward bias will continue if attention is not paid to setting appropriate base rates for the formula. Therefore, the Commission will seek submissions from the parties with respect to determining appropriate base levels and developing an effective methodology for deriving the inputs to the formula.

The Commission Panel understands that the conditions placed upon the implementation of the AAM

formula may well result in the 8.75 percent ROE being in place for the term of this Decision ending December 31, 2015. However, in consideration of the FRS, the Panel is of the view that this is appropriate.

FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015.

7.0 COST OF CAPITAL – SMALL UTILITIES

7.1 Introduction

When the Commission initiated the GCOC Proceeding, it identified the Affected Utilities, which included FEI and other FortisBC gas and electric utilities, PNG and Corix. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. In addition, the Commission identified Other Utilities that "may wish to participate in the GCOC Proceeding." This list included among others:

- Big White Gas Utility Ltd. and Sun Peaks Utilities Co. Ltd.;
- Central Heat Distribution Ltd.;
- Dockside Green Energy LLP;
- Hemlock Valley Electrical Services Limited; and
- River District Energy Limited (River District).

The recent emergence of thermal energy services (TES) in British Columbia has resulted in the creation, over the last few years, of a number of new on-site thermal energy systems and district energy systems, which are subject to the Commission oversight. For instance, FortisBC Alternative Energy Service Inc. (FAES), an affiliate of FEI and a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), now owns and operates or is proposing to develop the following regulated TES projects:

- Delta School District Number 37;
- Tsawwassen Springs Development;
- PCI Marine Gateway;
- TELUS Garden Thermal Energy System; and
- Kelowna District Energy System.

Key purposes identified by the Commission Panel in its Final Scoping Document were to establish:

(i) a method to determine the appropriate cost of capital for a benchmark low-risk utility in BC and how the Benchmark ROE will be reviewed and/or adjusted;

(ii) a generic methodology or process for determining each Affected Utility's cost of capital in relation to the benchmark utility's cost of capital; and

(iii) a framework for determining the appropriate cost of capital for other smaller utilities in the province.

Related to this framework, the scope of the proceeding included the following key activities:

(i) establish a generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility;

(ii) in certain circumstances, develop a methodology to establish a deemed capital structure and deemed cost of debt, particularly for those small utilities without third-party debt, which would involve setting a methodology on how to calculate a deemed interest rate.

(Exhibit A-3, Appendix B to Order G-47-12)

The Commission Panel also requested submissions regarding Stage 1 and Stage 2 review. The FBCU submitted it would be most efficient to break the process down into three groups which would be handled separately: one for the FBCU, a second for the PNG and a third for micro utilities including Corix and FAES and others. (Exhibit B1-22, pp. 10-11) By Order G-148-12, the Commission Panel directed that a Stage 2 will be added to this GCOC proceeding with the schedule to be determined prior to the end of Stage 1. (Exhibit A-21)

Transition to Stage 2

The purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by the Affected and Other Utilities as compared to the benchmark utility FEI. Based on this assessment the Panel will then determine how the risk differentials will impact the capital structures and the allowed ROE for these utilities.

The Panel acknowledges the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for TES systems, irrespective of the provider. This would include FEI and FAES's Thermal Energy Services, and similar systems to be operated by developers or providers like Corix. (Exhibit B1-9, p. 34) The Panel also notes the previously mentioned FBCU suggestion about dividing the Stage 2 process into three groups.

In anticipation of Stage 2, this section addresses issues related to the framework for determining the cost of capital for the smaller utilities, including all new small TES utilities. The appropriate method to determine interest rates for deemed debt will also be addressed. In this Decision, the definitions of "small utilities" and "micro utilities" are used interchangeably.

7.2 Framework for Establishing an Appropriate Cost of Capital – Equity Risk Premium

7.2.1 Is Size a Risk Factor in ROE and Capital Structure Determination?

Ms. Ahern, the expert witness for Corix states "it is conventional wisdom, supported by actual returns over time, that smaller companies tend to be more risky, causing investors to expect greater returns as compensation for that risk." Ms. Ahern further explains that smaller companies, for instance, face more risk exposure to business cycles and economic conditions, both nationally and locally. Similarly, the loss of revenues from a few larger customers would have a greater effect on a small company than on a much larger company with a larger, more diverse customer base. Moreover, smaller companies are generally less diverse in their operations as well as experiencing less financial flexibility. (Exhibit B2-7, pp. 6-7)

Ms. McShane, the expert witness for FBCU states that in the assessment of investment risk, size has two dimensions that should be considered in determining a utilities common equity ratio and ROE:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility.
2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Ms. McShane also points out that debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. (Exhibit B1-9, Appendix F, p. 134)

PNG submits "there was little to no evidence submitted that suggested or countered that size was not a significant factor." While precedents and empirical studies exhibit a broad range of explicit company size adjustments (150-436 bps), which introduces a degree of subjectivity, PNG further submits that "Stage 1 evidence concerning size as an independent factor was relatively uncontested." (PNG Final Submission, p. 13)

7.2.2 Stand-Alone Principle

Both Ms. Ahern and Ms. McShane reaffirm the importance of the stand-alone principle, which is "a cornerstone of Canadian utility regulation with a history dating to at least 1978." (Exhibit B1-9, Appendix F, p. 10, B2-9, BCUC 1.4.7) Therefore, even if a small utility is owned by a larger parent company, there should be no impact on the determination of the small size utility ROE and capital structure. Each utility within the Commission's jurisdiction should be evaluated on a stand-alone basis.

Ms. Ahern further states there is ample academic evidence that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. She submits "it is the use of funds invested and not the source of those funds which gives rise to the risk of any investment." She refers to the text of Brealey and Myers, which notes "Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put." (Exhibit B2-7, p. 7)

7.2.3 Academic Evidence of the Size Effect in Literature

In her filed evidence, Ms. Ahern provides additional examples of the academic literature, where the risk effects of a company's size on the investor required return is addressed:

Eugene F. Brigham, *Fundamentals of Financial Management:*

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-

> firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.
>
> (Exhibit B2-7, PMA-3, p. 4)

Giacchino and Lesser, *Principles of Utility Corporate Finance:*

> In general, smaller firms face greater financial risk than do large firms... Generally, firm size is measured in terms of total capitalization (i.e., the market value of a firm's equity). Empirical studies have typically found that small firms typically have higher returns over the long run than larger firms. (Exhibit B2-7, PMA-4, p. 3)

Fama and French, in *"The Capital Asset Pricing Model: Theory and Evidence,"* Journal of Economic Perspectives, note that size is a risk factor which must be reflected when estimating the ROE:

> ...the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market returns and are priced separately from market betas. (Exhibit B2-7, PMA-5, p. 14)

Based upon this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect of size on the rate of return on common equity.

Marc Reinganum, *"A Possible Explanation of the Small Firm Effect,"* The Journal of Finance:

> While the OLS estimates seem to understate the betas of small firms, the excess returns not explained by the misestimation could easily exceed twenty percent per year on average. Thus, one can conclude with confidence that the small firm effect is still a significant economic and empirical anomaly. (Exhibit B2-6, PMA-6, p. 9)

From her academic research, Ms. Ahern concludes that:

- The specific, unique risks of the investment (e.g. utility) must be reflected in the rate of return; and
- The size of an investment (e.g. size of the utility) is one of those unique risk factors for which investors must be compensated. (Exhibit B2-7, pp. 10-11)

7.2.4 Empirical Evidence for the Risk Effects of a Company's Size on the Investor's Required Rate of Return

Studies on small size and returns have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historical returns for companies of different sizes. Ms. McShane and Ms. Ahern state the analyses indicate that small companies tend to exhibit higher betas than larger companies. Two empirical studies reviewed by Ms. Ahern are:

Morningstar/Ibbotson Size Premium Study (Firm Size and Return)
Ibbotson SBBI – 2012 Valuation Yearbook

This study constructs decile (10) portfolios of the companies contained in the NYSE, AMEX and NASDAQ. Ms. Ahern suggests that the study can be used to determine the approximate risk premium due to size for a specific utility over the benchmark utility return. This is done by comparing the size premium appropriate for the decile in which the benchmark utility would fall based on the estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization.

	Decile	**Market Capitalization ($Millions)**	**Size Premium (%)**
Benchmark Utility	5	2,246 (average)	1.74
Micro-Cap	10	92	6.10
Size Premium			**4.36%**

(Exhibit B2-6, PMA-8, Table 7-1 and 7-5)

Duff & Phelps Size Study and Risk Study

The Size Study analyzes the relationship between equity returns and company size in a similar manner as the Morningstar Study. It could also be used to determine the magnitude of any necessary risk premium due to the size of a specific utility relative to the benchmark. In addition to presenting risk premia and size premia for 25 size-ranked portfolios using the traditional market

capitalization measure, this study also considers seven other measures of company size, including book value of equity, 5-year average net income, market value of invested capital, total assets, 5-year average EBITDA, sales and number of employees. (Exhibit B2-7, PMA-9, p. 30)

The Risk Study is an extension of the Size Study. The main difference is that while the Size Study analyzes the relationship between size and return, the Risk Study analyzes the relationship between fundamental risk measures (based on accounting data) and return. These are called "fundamental" measures of a company risk to distinguish these risk measures from a stock market-based measure of equity risk such as betas. (Exhibit B2-7, PMA-9, p. 65)

Corix provided a calculation of the size risk premium for micro utilities over the benchmark based on the Duff & Phelps Study. This resulted in a 3.89 percent risk premium as opposed to the 4.36 percent size premium based on the Morningstar Study. (Exhibit B2-8, Attachment to BCPSO 1.1)

7.2.5 Regulatory Support for Size Premium

Ms. Ahern provided only one example of a jurisdiction which has adopted the size premium concept. She cites the Florida Public Service Commission (FL PUC), which adds for small water utilities a bond yield differential, a 50 bps private placement premium and a 50 bps small utility risk premium to the ROE based upon the index of natural gas utilities. Regardless, Ms. Ahern recommends that the size risk of each utility be measured in accordance with the Morningstar/Ibbotson and the Duff & Phelps studies. Specifically, Ms. Ahern states "all of these risk premium spreads should then be averaged and through the exercise of informed expert judgement, a determination of the appropriate risk premium to be added to the benchmark utility return on equity to reflect the size risk of the utility/project relative to the benchmark utility." (Exhibit B2-9, BCUC 1.12.1; Exhibit B2-8, BCPSO 1.2.1)

In responses to IRs and during cross-examination, Ms. Ahern made it clear that she is not recommending any particular amount of a size premium to be adopted by the BCUC but is simply providing testimony for the purpose of establishing a framework. (T6:1128) Similarly, Ms. Ahern states the 4.36 percent risk premium shown in the example would only represent the upper limit of a size premium above the allowed benchmark ROE due to small size. Where in the 10th decile, Corix or any of its projects fall needs to be evaluated to determine the exact risk premium it would

propose. Corix stated it has not yet undertaken a comprehensive study of the appropriate size risk premium above the benchmark for each of its projects and indicated that such a study will be conducted in the next phase of the GCOC proceeding. (Exhibit B2-9, BCUC 1.13.2)

Ms. Ahern acknowledged that based on her experience the regulatory support for a specific size premium has been minimal and that ultimately any risk premium, whether it is linked to business risk in general or size specifically, is a matter of informed expert judgment. (T7:1278-1284) Further, Ms. Ahern could provide only seven cases out of over 200 regulatory proceedings where she has been involved that resulted in an allowed size adjustment. Yet, in a response to an undertaking, it appears that only two of those seven cases *specifically* reference "size" in the determination of the overall ROE and only one case granted a specific size premium. (Exhibit B2-14) Furthermore, the Panel notes that Ms. Ahern had recommended only modest size adjustments in the range of 25-50 bps in all those seven cases.

Ms. McShane concludes the empirical study findings indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual utilities in British Columbia. (Exhibit B1-9, Appendix F, p. 136)

Commission Determination

Stand-Alone Principle

The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a "new" utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.

The Size Premium

The Panel has considered the evidence on record regarding the academic literature on the size effect as well as the empirical evidence for the risk effects of a company's size on the required rate of return. Noteworthy is the lack of regulatory support for the recognition of a small size risk premium. Finally, the Panel notes the requirement for on-going exercise of informed judgment by both the Commission and experts retained by the utilities, which was acknowledged by Ms. Ahern.

As a result, the Panel recognizes the academic literature and empirical studies seem to support the importance of size in explaining returns. At the same time, however, the evidence presented does not indicate how adjustment for size should be implemented.

Accordingly, the Panel determines that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. Utilities are encouraged to use other methodologies or approaches to justify their risk differential in relation to the benchmark. The Panel has not been sufficiently persuaded to put any weight to the empirical studies reviewed to date.

The Panel notes that the Commission developed a risk matrix that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. The "size" factor is one of the risk factors included in the matrix. **The Panel recommends that the small utilities use this risk matrix attached as Appendix B to Order C-1-13 of the TELUS Garden Decision[9] in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the benchmark ROE**. For convenience, the risk matrix is attached in Appendix E of this decision. Small utilities, other than TES, can modify this matrix to facilitate a similar comparison of their own short and long-term risks to those of FEI.

The Panel is cognizant of the on-going Phase 2 of the Alternative Energy Solutions (AES) Inquiry,[10] which involves development of a regulatory framework for dealing with small TES utilities. This evolving process will further influence the nature and content of future TES applications.

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[9] Certificate of Public Convenience and Necessity Order C-1-13 and Reasons for Decision dated February 5, 2013, regarding FAES Telus Garden Thermal Energy Services

[10] In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Solutions and Other New Initiatives

7.3 Guiding Principles for Setting Deemed Capital Structure and Deemed Debt

7.3.1 Determination of Deemed Capital Structure

The Commission deems an appropriate common equity ratio for the utility. The resultant debt ratio is simply the residual between 100 percent and the deemed equity ratio. However, the deemed component typically incorporates actual debt issues where rates can be objectively observed and determined. In some cases, the utility manages its actual financing to mirror the deemed debt/equity ratio.

Ms. McShane explains the actual debt issues may consist of issues that have been made directly into public markets; they may be private placement to third party institutions such as bank or insurance companies, or they may be non-arms length issues between a utility and affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with rates that are based on market conditions. When the parent company issues debt, the subsidiary can enter into an arrangement with the parent for a specific portion of that debt issue, with the same terms as the third-party issue. Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent. (Exhibit B-1-9-6, McShane Evidence, Appendix F, p. 121)

7.3.2 Criteria for Setting the Deemed Capital Structure

Ms. Ahern, the Corix expert, states that an appropriate deemed capital structure should:

- be reasonable relative to or consistent with the average capital structure of the particular utility industry;
- reflect the specific utility's unique risks, including its relative size;
- be consistent with bond rating agency metrics; and
- provide the opportunity for the utility to earn a reasonable and fair rate of return, given its unique risks, e.g., size etc.

(Exhibit B2-7, p. 19)

Ms. McShane provides general principles that should be observed when setting the ROE and common equity ratio for utilities, regardless of size:

- The combination of ROE and common equity ratio awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility;
- The overall return awarded to each utility should be comparable, on a risk adjusted basis, to the overall return awarded to the benchmark utility;
- The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some utilities many not actually have a credit rating; and
- There is a trade-off between equity ratio and ROE. For example, if a utility is not fully compensated for higher business risk than that of the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility. (Exhibit B1-9-6, p. 129)

7.3.3 When Is Deemed Debt Appropriate?

The FBCU state the deemed debt is appropriate for small utilities in cases where raising debt is inefficient. For example, a separate division or class of service within a larger regulated utility can contain a stand-alone project. Similarly, a regulated utility subsidiary/affiliate within a larger corporate organization can face circumstances where either:

(i) The high cost of debt issuance relative to the size of the issue makes the effective debt cost higher than it would be otherwise; or

(ii) The size of the utility precludes it from accessing appropriate debt terms.

The FBCU further state that the assessment as to whether deemed debt is appropriate and efficient should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. Finally, FBCU state "it is reasonably clear that deemed debt would be appropriate for FEW (a separate legal entity), the Fort Nelson Division of FEI, and FAES." (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.1, 1.140.2)

7.3.4 Setting the Appropriate Deemed Debt Rate and Term

The FBCU state that deemed debt rates and duration should reflect the particular circumstances of each utility. Utilities for which a deemed cost of debt might be appropriate may have differing profiles; FEW, for instance, is not the same as one of FAES's TES projects or Corix's UniverCity project. The appropriate term of debt may also vary even among projects with a broadly similar risk profile. (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.2)

Ms. McShane submits as a general proposition that the term should reflect the long-term nature of the assets and offers the following additional considerations:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term for the debt.
2. The higher the risk of the specific operation, the less their ability would be to obtain "real" debt on a long-term basis; i.e., on terms longer than 10 years. The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.
3. The appropriate term for the deemed debt also depends on the state of the capital markets.

Ms. McShane concludes that the individual utilities' circumstances may differ in terms of risk, the funding requirements and appropriate terms of debt. Accordingly, she recommends that the Commission continue to address the cost of deemed debt for each utility separately, on a case-by-case basis. In her view, there is no "one size fits all" cost mechanism. (Exhibit B1-9-6, pp. 123-124)

Commission Determination

Before addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission Panel wishes to reaffirm certain principles for the Stage 2 GCOC proceeding framework.

(i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

(ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;

(iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and

(iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

Related to the issue of deemed capital structure and deemed debt are two key questions that the Stage 2 GCOC proceeding must address more comprehensively:

1. Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
2. How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

7.4 Appropriate Portions of Short-Term and Long-Term Debt in the Deemed Capital Structure

In British Columbia, in some of the more recent TES Decisions, the Commission has considered deeming a portion of overall debt to short-term debt. To date no determination has been made to put this into effect. However, the Panel notes that the OEB has officially deemed a standard four percent proportion of short-term debt component for utilities under its jurisdiction for reasons that it outlined in its 2006 Decision:

(i) All utilities actually use some short-term debt;

(ii) Short-term debt is generally less expensive than long-term debt and provides greater financing flexibility; and

(iii) While actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of distributors regulated by the OEB.[11]

[11] OEB, Report of the Board on Cost of Capital and 2nd Generation incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 9-10

In 2009, the OEB reaffirmed this practice for natural gas distributors as well. It also updated its methodology to estimate the deemed short-term debt rate. (Exhibit A2-21, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, EB-2009-0084)

Ms. McShane states there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt. She notes that annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues. Based on her filed evidence she further states that the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1 percent to 2 percent. Her review of 2010 data for Ontario electricity distributors indicated that the average and median actual short-term debt ratios were at 2.9 percent and 0.4 percent respectively. (Exhibit B1-9-6, pp. 125-127)

Ms. Ahern states that conceptually the maturity of the debt capital should match the life of the assets being financed. But when the inclusion of short-term debt is optional, its inclusion should be based upon several criteria:

- If its use is sporadic and hence, volatile, it should not be included in the capital structure. However, if its use is consistent and especially at a significantly high level, it is likely financing rate base and possibly should be included;
- If its use is seasonal and self-liquidating, e.g., financing short-term inventories of natural gas in anticipation of heating season, it probably should not be included;
- If short-term debt is financing working capital, it should be included;
- If it is used as bridge financing until permanent financing can be put in place it should be included at the expected cost rates of that permanent financing; and
- If the short-term debt financing construction projects and if the Construction Work In Progress (CWIP) are included in rate base the short-term debt should be included. (Exhibit B2-7, pp. 23-24)

The FBCU provided information showing actual percentages of short-debt for FEI, FEI – Fort Nelson, FEVI, FEW, and FortisBC Inc. for the 2002-2012 period. While there has been significant fluctuation over the years, the average percentages for the period as a share of capital structure amounted to

5.28 percent, 8.58 percent, 10.77 percent, 13.10 percent and 5.27 percent for each respective utility. (Exhibit B1-24, BCUC 2.189.1, 2.189.2)

Commission Determination

The Commission Panel finds it as an accepted fact that all utilities use some short-term debt financing. The FBCU IR responses clearly support this. While there are varying reasons for its use, the evidence demonstrates that, on average, utilities always carry a small portion of short-term debt in their capital structure. The construction work in progress, due to its nature, is often financed by short-term debt.

Accordingly, the Commission Panel finds it reasonable and prudent to include a deemed component of short-term debt in the capital structure for all small utilities without third-party debt to reflect reality. To establish the percentage of short-term debt to be deemed, the Panel has considered testimony of Ms. McShane, FBCU IR responses and the OEB established practice in Ontario. **While acknowledging that there is no correct amount, the Panel concludes that a four percent component for deemed short-term debt provides a reasonable proxy as it is the midpoint of the range of actual short-term borrowing.**

7.5 Setting the Deemed Interest Rates

7.5.1 Deemed Interest Rate for Long-Term Debt

Parties acknowledge that there are at least three reasonable options for determining the deemed interest rate applicable to a small utility without third-party debt. These options are summarized below.

FBCU Option 1:

Step 1: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. The FBCU submit this approach is consistent with the stand-alone principle, and is how FEW has financed the debt component of its capital structure. (Exhibit B1-9, pp. 29-30; Exhibit

B1-20, BCUC 1.141.1, 1.141.5, 1.144.2) A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 123; Exhibit B1-20, BCUC 1.147.1)

Step 2: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms. (Exhibit B1-9, p. 30)

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond. (Exhibit B1-9, p. 30; Exhibit B1-24, BCUC 1.141.5.2; Exhibit B1-24, BCUC 2.188.2, 2188.3)

FBCU Option 2:

Ms. McShane identified an alternative approach to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and interest rate based on an approved capital structure. Currently, FEI-Fort Nelson debt is deemed and the rate is the embedded cost of debt. (Exhibit B1-20, BCUC 1.141.1, 1.141.6) The FBCU submit that this is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits of issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity raising the debt will be able to recover its actual incurred cost of debt. (Exhibit B1-20, BCUC 1.148.8)

Corix Option:

Corix supports FBCU's recommendation to apply one benchmark credit spread for small utilities to provide regulatory efficiency. To align with the proposed method, the benchmark credit spread would reflect the spread for BBB and BBB (low) rated debt relative to the underlying 10 year GoC bond yield and would reflect incremental risk of small utilities. Corix states that with the benchmark set for small projects, project stakeholders and interveners can then justify any variances from the benchmark depending on the risk exposure. (Exhibit B2-9, BCUC 1.26.3, 1.27.1, 1.46.5, 1.46.7, 1.46.11)

Commission Staff Option:

This option was raised in order to account for the scarcity of BBB-rated utilities in Canada that can be used as proxy, and for the possibility that utility ratings can be changed.

Step 1: Obtain the yield on an appropriate GoC bond as the benchmark.

Step 2: Assign a credit rating to the stand-alone utility/project based on an assessment of financial and business risk (e.g., BBB, other)

Step 3: Obtain the bond yield (credit) spread between GoC bond and a high grade utility (A or A low) and add it to the rate in Step 1.

Step 4 Add a premium, if required, to the credit spread in Step 3. This premium will be calculated as the credit spread between high grade utility bonds (A or A low) and utility bonds of the credit rating estimated in Step 2. The use of historical data (e.g., two most recent years) to have more data points could be considered. (Exhibit A2-43; Exhibit B1-20, BCUC 1.141.9; Exhibit B1-24, 2.188.6; Exhibit B2-9, BCUC 1.26.6)

The FBCU submits it is generally supportive of the Staff option but raised one concern. Ms. McShane cautioned that for any method involving the use of credit rating proxy companies, care should be taken to employ reasonable credit ratings. She re-emphasized that an appropriate credit for small utilities would be BBB to BBB (low), as the inherent risk of small size would preclude them from achieving higher ratings:. "As it is much more likely that the small utility would be BBB on a standalone basis, it makes sense to use a BBB yield as the benchmark to begin with rather than using A-rated proxies." (FBCU Final Submission, pp. 164-165; T5: 680-681)

Commission Determination

The evidence and Final Submissions suggest that setting the deemed interest rate is not a very controversial issue. However, each option reviewed has advantages and disadvantages. The Panel also notes that similar approaches have been adopted in number of recent TES Decisions. For example, BBB-rated proxies were used for the Delta School District Number 37 and Tsawwassen Springs projects.

The Commission Panel has already found that the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis. Based on this the Panel recommends that on a go-forward basis the FBCU's Option 1 be used as a guideline for setting the deemed debt rate. The Panel is cognizant of the refinement proposed by Commission Staff to account for the scarcity of BBB-rated utilities in Canada that can be used as a proxy. Should this become a major issue in the future, the Commission can consider switching to use the Commission Staff Option as the guideline.

Because the deemed long-term debt by definition is set for a fixed term, the Panel finds that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt. The impact of the rate change could be considered a subsequent revenue requirement review.

However, to allow some flexibility, the utilities will have an option to apply for a rate adjustment in accordance with the following reopener-criteria:

- **A measurable change in market conditions**
- **A measurable change in actual debt costs**

The Commission will consider each application for a rate adjustment on a case-by-case basis.

7.5.2 Deemed Interest Rate for Short-Term Debt

The FBCU state the basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate determination. It would be based on indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate (CDOR). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances (BAs), which reflect the short-term benchmark rate plus the company's applicable credit spread. (Exhibit B1-9, p. 31) In response to IRs, the FBCU clarified that quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer. (Exhibit B-20, BCUC 1.44.2, 1.44.3)

Ms. McShane states that three-month BAs are also a common benchmark for establishing the cost of short-term debt for utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 127-128) In response to IRs the FBCU confirm that either the 3-month CDOR or 3-month BA rate is reasonable for setting the short-term rate. Regarding the indicative credit spread quotes, the FBCU state the following approach used by the OEB is reasonable: the OEB obtains up to six quotes from banks. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes obtained. (Exhibit B1-20, BCUC 1.144.4) The FBCU submit that the OEB formulaic approach is an efficient and transparent way of estimating a deemed short-term debt rate. However, the FBCU stress that the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally corresponds to long-term credit ratings in the A category; i.e., higher than would be applicable to the small utilities. To overcome this problem, the FBCU suggest using a more reasonable short-term credit rating, one that would correspond to a BBB/BBB (low) on the long-term rating scale. (Exhibit B1-20, BCUC 1.144.5, 1.144.5.1)

Commission Determination

The Commission Panel recommends that small utilities use either the 3-month CDOR or 3-month BA rate as a basis and obtain 3-4 quotes to establish the credit spread for the purpose of setting the deemed short-term interest rate. Because it is highly unlikely that small utilities, especially the TES utilities/projects, will have frequent revenue requirement reviews, the Panel finds that there is no requirement for an annual adjustment mechanism. **The short-term rates are to be reset at the time of the revenue requirement review only.**

8.0 OTHER MATTERS

8.1 Reliance on Less Complex Financial Methodology

Expert witnesses in this proceeding expressed reluctance to use more complex models that could improve understanding and/or estimating the cost of equity. For instance, Ms. McShane states: "I think it's reasonable to try to capture these other factors. I know that it's been difficult to have regulators accept the Fama/French type models ..." (T5:721)

In response to a question from Commissioner Giammarino, Dr. Vander Weide expressed similar concerns:

> **COMMISSIONER GIAMMARINO:** "And [Fama/French] suggest that maybe the future is in an inter-tempo CAPM, that has multi factors. And that would allow for changes in the opportunities – the investments that are available to investors. Did you consider that as an alternative?" (T6:1103)
>
> **DR. VANDER WEIDE:** "That would certainly be an alternative, but from my years in testifying on the cost of capital, I have realized that there are two qualities that make a model present reasonable evidence. One is that it's -- you can estimate the inputs to the model reasonably well, and two, it has to be reasonably easy to understand. So that one can judge the model in the context where everyone doesn't have Ph.D.s in finance or economics. And once you get into dynamic capital asset pricing models, to me that's getting into a level that's too complicated for discussion in a public forum." (T6:1103)

Although Dr. Booth added a credit spread adjustment to his CAPM analysis, he also expressed a similar sentiment about adding further factors to his CAPM, as shown by the following exchange:

> **COMMISSIONER GIAMMARINO**: …there is sort of a well-established set of suspects. You've looked at one.
>
> **DR. BOOTH:** Correct.
>
> **COMMISSIONER GIAMMARINO:** So why not look at all?
>
> **DR. BOOTH:** Two reasons. First of all, with all due respect to the Commission, it's a question of getting things to the Commission in an understandable way through cross-examination. And KISS works. That a simple way of looking at these things, I think, makes sense. The only time,

for example, I saw a company put forward the Fama French model was before the Gaz Métro. And the witness had a real tough time with the more complicated model. And the Régie was very reluctant to adopt a more complicated model.

COMMISSIONER GIAMMARINO: Right.

DR. BOOTH: So when you get down to conditioning, you're absolutely correct. You think about Chandrell and Ross, and you think about economic factors affecting security returns, you can go to more measures. Does the addition of more measures make the testimony more saleable to a Commission? And the answer to that is generally no. It may make it more saleable in an academic seminar but it's easier, I think, to pick on one thing that people can relate to – credit spreads – that was picked up in most of the hearings in 2009, which seems to make sense, and seems to be consistent with the academic literature, than to go through a more complicated model with term structure, yield parameters, dividend yields or other conditioning variables. So, I pick one, the credit spread. (T8:1658-59)

The Commission Panel accepts that evidence should meet some basic criteria. For example, expert witnesses must have confidence in their estimates; and the evidence must be understandable to the Panel, ideally for all parties involved. The Panel is, however, concerned that experts pay undue attention to prior assessments of the limits of what the Commission will understand and/or accept. While evidence put forward should be as helpful as possible to a Panel dealing with the difficult task of determining the appropriate rate of return and capital structure, it should reflect the expert's best judgment about the state-of–the-art methodology, which should in turn be presented in an understandable way.

It is the Commission Panel's opinion that the purpose of a cost of equity model is to provide structure to the discussion of 'what is a fair rate of return.' Models used to fulfill this purpose provide structure and clarity, and in turn provide a basis for determining the truth of any particular assessment. Models are abstractions and, by definition, imperfect representations. As a result, it is up to the Panel to decide how much confidence it should put in various models that have unrealistic assumptions and do not explain returns perfectly. The Panel must also understand where judgment needs to be applied to the output delivered by these models.

Specifically, in Section 5.2.1, the Panel identified some of the weaknesses related to the adjustments to the CAPM. In particular, the experts expressed reluctance to include additional potential extensions to the CAPM because they were perhaps "too complex" to the Panel. This in turn leaves

open what results other extensions could imply. Similarly, in the beginning of Section 5.2 the Panel identified the lack of global perspective in assessing the investor's portfolio. A more clear set of principles, including a definition of FEI's investors' portfolios (i.e., Global, North American, Canadian) would have been valuable. Accordingly, the Panel invites more comprehensive evidence on these topics in the future.

The Commission Panel believes that one of the roles of the expert is to guide the regulator in evaluating the trade-off between the complexities of the structures needed to evaluate arguments versus the reliability of the structures. This trade-off is at the heart of cost of capital hearings. As this trade-off evolves constantly, the testimony should evolve with it.

8.2 FEI - The Benchmark Utility

Based on the evidence related to long and short-term risk before the Commission Panel we are in agreement with describing FEI as the "benchmark utility" rather than a "low-risk benchmark utility." While the Panel has determined that the level of risk is somewhat less in a number of areas than those which existed at the time of the 2009 Decision, there has been little change in many areas. Therefore, we are of the view that describing FEI as low-risk would not be appropriate. Accordingly, for the purposes of Stage 2 of the GCOC, FEI will be referred to as the benchmark utility. **The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

The issue as to whether FEI is a pure-play gas distribution received little direct attention beyond the October 4, 2012 procedural conference. However, the Commission Panel has considered the issue in the context of the level of throughput related to alternative energy initiatives. It appears that FEI's forecasted throughput related to alternative energy initiatives is relatively small. Under cross-examination, FBCU witness, Mr. Stout with reference to natural gas transportation initiatives stated:

> "...we forecast two and a half to three petajoules in 2017. I think even if you go to some volume that's in the 10 to 15 petajoule range, it's still less than 10 percent of the throughput of the system, say 5 to 10 percent of the total throughput". (T3:317)

Based on Mr. Stout's testimony, the Commission Panel accepts that FEI at this point in time is primarily a pure-play gas distribution utility.

While Stage 1 of the GCOC proceeding has been mainly concerned with determining an appropriate cost of capital for the benchmark utility, Stage 2 will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk. The Commission Panel considers that it is feasible that a stand-alone public utility may face overall business risks that are either higher, lower or the same as the benchmark utility.

The primary factors that have influenced FEI's long-term risk have been identified and addressed in Section 4.2. In addition, we have further identified and made determinations upon FEI's short-term risk. In Stage 2 of the GCOC, the public utilities, where appropriate, will be required to describe how they differ from the benchmark utility on these and any other risk factor as it relates to them. In addition, in Section 7.2.5 the Commission Panel has described a risk matrix (included in Appendix E) as a tool for the small utilities (especially the TES utilities) to further assist in justifying their case for an appropriate capital structure and risk premium.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

Original signed by:

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

R. GIAMMARINO
COMMISSIONER

Original signed by:

M.R. HARLE
COMMISSIONER

Original signed by:

L.A. O'HARA
COMMISSIONER

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-75-13

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Generic Cost of Capital Proceeding

BEFORE: D.A. Cote, Commissioner/Panel Chair
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner
R. Giammarino, Commissioner

May 10, 2013

O R D E R

WHEREAS:

A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt;

B. Appendix C to Order G-20-12 divided public utilities into two categories for the purpose of the proceeding: "Affected Utilities" and "Other Utilities;"

C. FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc. (FortisBC)[collectively (FBCU)]; Corix Multi-Utility Services Inc. (Corix); and Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG) registered as Affected Utilities. The British Columbia Hydro and Power Authority (BC Hydro) and the River District Energy (RDE) registered as Other Utilities;

D. Among the Interveners who registered for the proceeding, the Association of Major Consumers of BC (AMPC), British Columbia Pensioners' and Seniors' Organization (BCPSO), Commercial Energy Consumers (CEC) [collectively B.C. Utility Customers], and the Industrial Customers Group of FortisBC Inc. (ICG) actively participated;

E. By Order G-47-12 dated April 18, 2012, the Commission issued the Final Scoping Document for the proceeding. The Scoping Document sets out the purpose and the scope of the proceeding. Matters within the scope of the proceeding included, among others, the appropriate cost of capital and its effective date for a benchmark low-risk utility, the establishment of a benchmark ROE, the consideration of an automatic adjustment mechanism, and the deemed capital structure and deemed cost of capital for small utilities without third-party debt;

F. By Order G-50-12 dated April 19, 2012, the Commission, among other matters, set out the further procedural matters to be addressed in the proceeding and a Preliminary Minimum Filing Requirements (MFR) for Affected Utilities document. Parties were invited to make submissions on the Preliminary MFR for Affected Utilities by May 3, 2012, and on the allocation of Participant Assistance/Cost Awards (PACA), PACA eligibility, and/or the Draft Preliminary Regulatory Timetable by May 9, 2012;

G. By Order G-72-12 dated June 1, 2012, the Commission, among other matters, issued the Final Minimum Filing Requirements for Affected Utilities and the Preliminary Regulatory Timetable for the proceeding;

H. On June 8, 2012, the Commission released "A Survey of Cost of Capital Practices in Canada" prepared by The Brattle Group for the Commission (Brattle Report). Utilities and Interveners were provided with the opportunity to ask Information Requests on the Brattle Report;

I. By Order G-84-12 dated June 20, 2012, the Commission amended the Preliminary Regulatory Timetable, establishing, among other things, a Procedural Conference for October 2, 2012 and the commencement date for an oral hearing, if required, on December 12, 2012. The Procedural Conference was subsequently rescheduled to October 4, 2012;

J. At the Procedural Conference the Commission received, among others, submissions on the following items: (1) the appropriate benchmark utility for the determination of the generic cost of capital; (2) whether a Stage 2 for the purpose of determining an appropriate cost of capital for Affected and Other Utilities to immediately follow Stage 1 was desirable; (3) whether an oral phase was required and (4) the proposed timetable going forward;

K. By Order G-148-12 dated October 11, 2012, the Commission determined that : (1) FEI in its present pre-amalgamation state, would serve as the benchmark for the proceeding and whether FEI in 2012 is a pure play gas distribution utility would be determined following the hearing of further evidence; (2) a Stage 2 would be added to the proceeding with the schedule to be determined prior to the end of Stage 1; and (3) the review of the proceeding would continue by way of an oral hearing commencing on December 12, 2012;

L. By Order G-187-12 dated December 10, 2012, the Commission ordered that: (1) the current ROE and capital structure for FEI, the designated benchmark utility, and all regulated entities in B.C. that rely on the benchmark utility, except British Columbia Hydro and Power Authority, are to be maintained and made interim, effective January 1, 2013; and (2) any determinations of the premiums on the benchmark ROE and capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decision in Stage 2; M. The oral public hearing took place over a period of seven days between December 12, 2012 and December 21, 2012. A total of eight witness panels from FBCU and Interveners gave evidence;

N. FBCU, PNG, Corix, AMPC/CEC, ICG and BCPSO filed Final Submissions. FBCU filed a Reply Submission; and

O. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-75-13

NOW THEREFORE, the Commission orders as follows:

1. The common equity component appropriate for the benchmark utility, FEI, effective January 1, 2013 is 38.5 percent.

2. A Return on Equity (ROE) for the benchmark utility, FEI, is established at 8.75 percent effective January 1, 2013.

3. An Automatic Adjustment Mechanism (AAM) formula for annually setting the ROE of the benchmark utility between ROE proceedings is adopted commencing January 1, 2014. The AAM formula will operate until December 31, 2015. The implementation of the model will be subject to conditions outlined in the Decision.

4. FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015.

5. The common equity component and the ROE approved in Paragraphs 1 and 2 of this Order will continue to serve as the Benchmark cost of capital for any other utility in British Columbia that uses a Benchmark Utility to set rates.

6. Within 30 days of the date of this Order, FEI is to file:

   (a) a document setting out how and when it will implement the change to its capital structure;

   (b) amended rate schedules in accordance with paragraphs 1 and 2 of this Order as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013.

7. Small utilities without third-party debt are to include a deemed component of short-term debt of 4 percent.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-1	G-20-12 (Feb 28, 2012)	• Stated purpose in establishing the GCOC proceeding • All regulated utilities determined to be applicants in this proceeding. Utilities are divided into "Affected Utilities" and "Other Utilities." • Issued initial regulatory timetable for registration of Utilities and Interveners and written submissions on the Preliminary Scoping Document
A-3	G-47-12 (April 18, 2012)	• Issued Final Scoping Document
A-5	G-50-12 (April 19, 2012)	• Issued preliminary Minimum Filing Requirements (MFR) • Issued preliminary regulatory timetable for written submissions on the MFR and the cost allocation of Participant Assistance/Cost Awards (PACA) and PACA eligibility
A-6	G-72-12 (June 1, 2012)	• Issued Final MFR • Determined the principles in the allocation of PACA costs and PACA cost eligibility • Considered expansion of the current proceeding by conducting the GCOC proceeding in two stages • Issued preliminary regulatory timetable for a Procedural Conference and Stage 1 of the GCOC proceeding. • Put on the record the terms of reference for the survey Report carried out by The Brattle Group
A-9	Order G-84-12 (June 20, 2012)	• Issued amended preliminary regulatory timetable

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-16 and A-17	Letter L-52-12 (September 13, 2012)	• Established the amended date and agenda for the Procedural Conference
A-22	G-148-12 (October 11, 2012)	• Determined that FEI in 2012 in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding • Determined that a Stage 2 will be added to the proceeding • Determined that review will take place by an oral hearing commencing on December 12, 2012
A-30	G-187-12 (December 10, 2012)	• Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013

LIST OF APPEARANCES

G. Fulton, Q.C.	Commission Counsel
L. Bussoli	Commission Counsel
M. Ghikas	FortisBC Utilities
T. Ahmed	FortisBC Utilities
M. Cheesman	Corix Multi-Utility Services Inc. (Corix)
J. Kennedy	Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
R.B. Wallace, Q.C.	Association of Major Power Customers of B.C. (AMPC)
R. Hobbs	Industrial Customers Group of FortisBC Inc. (ICG)
L. Worth	British Columbia Pensioners' and Seniors' Organization (BCPSO)
E. Kung	British Columbia Pensioners' and Seniors' Organization (BCPSO)
T. Braithwaite	British Columbia Pensioners' and Seniors' Organization (BCPSO)
C. Weafer	Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Commercial Energy Consumers of British Columbia (CEC)
J. Christian	British Columbia Hydro and Power Authority (BC Hydro)
B. Hobkirk	British Columbia Hydro and Power Authority (BC Hydro)
R. Hanson	River District Energy
J. Quail	Canadian Office and Professional employees' Union Local 378

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LIST OF PANELS

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PANEL 1 - COMPANY EVIDENCE

Roger A. Dall'Antonia	Vice President, Strategic Planning, Corporate Development and Regulatory Affairs (Panel Chair)
Douglas Stout	Vice President, Energy Solutions and External Relations
Cynthia Des Brisay	Vice President, Energy Supply and Resource Development
Michele Leeners	Vice President, Finance and CFO

PANEL 2 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

Kathleen C. McShane, MBA, CFA	President Foster Associates, Inc.

PANEL 3 - EXPERT OPINION ON AUTOMATIC ADJUSTMENT MECHANISMS

James M. Coyne	Concentric Advisors

PANEL 4 - EXPERT OPINION ON CAPITAL MARKETS

Aaron M. Engen	Managing Director BMO Capital Markets (Energy Infrastructure Group)

PANEL 5 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

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Pauline M. Ahern, MBA	Principal AUS Consultants

LIST OF PANELS

THE INDUSTRIAL CUSTOMERS GROUP OF FORTISBC INC. (ICG)

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THE ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC), THE COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC), THE BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO), COLLECTIVELY THE BC UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 1

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated February 28, 2012 and Order G-20-12 – Establishing an initial Regulatory Timetable
A-2	Letter Dated April 17, 2012 – Response clarifying Union Gas's Intervener Status
A-3	Letter dated April 18, 2012 and Order G-47-2012 – Reasons for Decision and Final Scoping Document
A-4	Letter dated April 18, 2012 – Appointment of Panel
A-5	Letter dated April 19, 2012 - Order G-50-12 List of Further Procedural Matters
A-6	Letter dated June 1, 2012 - Order G-72-12 Issuing Preliminary Timetable, PACA costs, Final Minimum Filing Requirements for Affected Utilities
A-7	Letter dated June 6, 2012 - Request for Variance of Regulatory Timetable Order G-72-12
A-8	Letter dated June 8, 2012 – Commission Consultant's Survey Report
A-9	Letter dated June 20, 2012 – Order G-84-12 - Amended Preliminary Regulatory Timetable
A-10	Letter dated July 27, 2012 – Request for Comments on the Addition of a Panel Member
A-11	Letter dated August 22, 2012 – Appointment of Commissioner Mr. R. Giammarino
A-12	Letter dated August 31, 2012 – Information Request No. 1 to FortisBC Utilities
A-13	**CONFIDENTIAL** Letter dated August 31, 2012 – CONFIDENTIAL Information Request No. 1 to FortisBC Utilities
A-14	Letter dated August 31, 2012 – Information Request No. 1 to PNG

Exhibit No.	Description
A-15	Letter dated August 31, 2012 – Information Request No. 1 to Corix
A-16	Letter dated September 13, 2012 – L-52-12 Amending Regulatory Timetable
A-17	Letter dated September 27, 2012 – Agenda for Procedural Conference
A-18	Letter dated October 9, 2012 – Information Request No. 2 to FortisBC Utilities
A-19	**CONFIDENTIAL** Letter dated October 9, 2012 – CONFIDENTIAL Information Request No. 2 to FortisBC Utilities
A-20	Letter dated October 9, 2012 –Information Request No. 2 to Corix
A-21	Letter dated October 11, 2012 – Order G-148-12 and Reasons for Decision
A-22	Letter dated October 24, 2012 - Request to Access Confidential Material
A-23	Letter dated October 31, 2012 - Access to Confidential Material Response
A-24	Letter dated November 1, 2012 – Confidential Material Access to AMPC (Exhibit C6-11)
A-25	Letter dated November 16, 2012– Information Request No. 1 to ICG on Intervener Evidence
A-26	Letter dated November 16, 2012– Information Request No. 1 to AMPC on Intervener Evidence
A-27	Letter dated November 20, 2012 – Request for submissions
A-28	Letter dated December 3, 2012 – Oral Public Hearing Information
A-29	Letter dated December 5, 2012 – Opening Statements Clarification
A-30	Letter dated December 10, 2012 - Commission Order G-187-12 establishing the current ROE and capital structure
A-31	Letter dated February 14, 2013 – Commission Response to request for extension

Exhibit No.	Description
COMMISSION STAFF DOCUMENTS	
A2-1	Letter Dated February 28, 2012 - Commission Staff Filing British Columbia Utilities Commission letter dated November 28, 2011-Preliminary Notification of Initiation of Generic Cost of Capital Proceeding
A2-2	Letter Dated February 28, 2012 - Commission Staff Filing the Terasen Utilities (December 8, 2010) – Automatic Adjustment Mechanism Review
A2-3	Letter dated June 8, 2012 – Commission Staff Filing the Brattle Group Survey of Cost of Capital Practices in Canada
A2-4	Letter dated July 12, 2012 - Commission Staff Filing Response to AMPC Information Request to Commission Consultants
A2-5	Letter dated July 12, 2012 - Commission Staff Filing Response to FEU Information Request on the Consultants Survey Report
A2-6	Letter dated July 12, 2012 - Commission Staff Filing Response to Industrial Customer Group Information Request on the Consultants Survey Report
A2-7	Letter dated July 12, 2012 - Commission Staff Filing Response to BCOAPO Information Request to Consultants Report
A2-8	Letter dated July 12, 2012 - Commission Staff Filing Response to CEC Information Request to Consultants Report
A2-9	Letter dated July 13, 2012 – Commission Staff Filing BCUC Request for Proposal for a Survey of Canadian Cost of Capital Practice Report
A2-10	Letter dated August 31 2012 – Commission Staff Filing Behavior of the Firm under Regulatory Constraint by Harvey Averch and Leland L. Johnson
A2-11	Letter dated August 31 2012 – Commission Staff Filing Extract from Terasen 2005 and 209 ROE CAP Applications
A2-12	Letter dated August 31 2012 – Commission Staff Filing Extract from FEU 2012-13 Revenue Requirements Decision
A2-13	Letter dated August 31 2012 – Commission Staff Filing Extract from Bloomberg News (Report dated August 6, 2012)

Exhibit No.	Description
A2-14	Letter dated August 31 2012 – Commission Staff Filing Capital Structure - A Comparison
A2-15	Letter dated August 31 2012 – Commission Staff Filing Summaries of Reports and Notes from Recent Credit Rating Agencies and Investment Banks on FEI's Risk and Credit Metrics
A2-16	Letter dated August 31 2012 – Commission Staff Filing Extract from Washington Utilities and Transportation Commission Order 08 Decision
A2-17	Letter dated August 31 2012 – Commission Staff Filing Fitch Affirms National Fuel Gas' IDR at 'A'
A2-18	Letter dated August 31 2012 – Commission Staff Filing The City of Vancouver - District Energy Connectivity Standards Information for Developers
A2-19	Letter dated August 31 2012 – Commission Staff Filing City of Surrey – District Energy System By-law, 2012, No. 17667
A2-20	Letter dated August 31 2012 – Commission Staff Filing Extract from BCUC Information Request No. 2 to River District Energy Limited Partnership
A2-21	Letter dated August 31 2012 – Commission Staff Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities December 11, 2009
A2-22	Letter dated August 31 2012 – Commission Staff Filing Ontario Energy Board Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012
A2-23	Letter dated August 31 2012 – Commission Staff Filing Summary of Reports from Recent Credit Rating Agencies and Investment Banks on PNG's Risks and Credit Metrics
A2-24	Letter dated October 9, 2012 – Commission Staff Filing Bradshaw et al. - Playing Favorites
A2-25	Letter dated October 9, 2012 – Commission Staff Filing CTA-Risk-Free Rate Determination
A2-26	Letter dated October 9, 2012 – Commission Staff Filing Exhibit A2-26 OEB Cost of Capital Parameter, May 1 2012

Exhibit No.	Description
A2-27	Letter dated November 16, 2012 - Commission Staff Filing Cost of Capital by Sector_NYU_Value Line Database
A2-28	Letter dated November 16, 2012 - Commission Staff Filing Gau, Thompson 2012 Capitalization Rate Study
A2-29	Letter dated November 16, 2012 - Commission Staff Filing Schaeffler and Weber- The Cost of Equity of Network Operators
A2-30	Letter dated November 16, 2012 - Commission Staff Filing TD-Long-Term Returns October 2012
A2-31	Letter dated November 16, 2012 - Commission Staff Filing Ashton et al- Analysts' Optimism in Earnings Forecasts
A2-32	Letter dated November 16, 2012 - Commission Staff Filing Understanding Corporate Bond Spreads Using Credit Default Swaps
A2-33	Submitted at Oral Hearing December 12, 2012 – Commission Staff Filing FEU 2012-2013 Revenue Requirements G-44-12 Compliance Filing
A2-33-1	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing page 1 of letter dated may 1, 2012 to BCUC from FortisBC, with two pages attached
A2-34	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Vancouver Sun Article Natural gas seen as green fuel
A2-35	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Staff Witness Aid
A2-36	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing pages 7 to 10 from Standard & Poors Report
A2-37	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Long-Term Economic Forecast, TD Economics, September 18, 2012
A2-38	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Attachment 8.2(A), page 17 of 18, Results of Differences in Systematic Risk
A2-39	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Extract from Order No. 09-176 from Public Utility Commission of Oregon

Exhibit No.	Description
A2-40	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Rating Report, February 29, 2012 from DBRS
A2-41	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Document Headed Moody's Investors Service, Credit Opinion: FortisBC Energy Inc.
A2-42	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Five-Page Document, First Page Headed Returns on Average Common Stock Equity for Sample of U.S. Utilities
A2-43	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Approaches to Estimating the Deemed Interest Rate for Long Term Debt
A2-44	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Excerpt of FEI Kelowna DES CPCN Application
A2-45	Submitted at Oral Hearing December 17, 2012 – Document Headed Credit Rating and Equity Risk Premium
A2-46	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Weathering the Headwinds to Canada's Economic Growth 21 November 2012
A2-47	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Puget Sound Energy Inc.
A2-48	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Power & Utilities Research, the One-Two Punch: Growth Combined with Attractive Yield
A2-48-1	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Extract from BMO Capital Markets, page 11, Headed Power & Utilities
A2-49	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Ontario Energy Board, Report of Board, December 20, 2006
A2-50	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First
A2-51	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Witness Aid Prepared by Commission Staff Entitled Informed Expert Judgment

Exhibit No.	Description

AFFECTED UTILITIES DOCUMENTS

B1-1	**BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU)** Letter Dated March 15, 2012 – Notice of Registration
B1-2	Letter Dated March 21, 2012 – FBCU Submission on the Preliminary Scoping Document
B1-3	Letter Dated May 3, 2012 – FBCU Submission on Minimum Filing Requirements
B1-4	Letter Dated May 9, 2012 – FBCU Submission regarding Order G-50-12 Appendix A
B1-5	Letter Dated June 5, 2012 – FBCU Submitting Request for Variance of Preliminary Regulatory Timetable
B1-6	Letter Dated June 5, 2012 – FBCU Reply Submissions regarding Request for Variance of Preliminary Regulatory Timetable
B1-7	Letter Dated June 22, 2012 – FBCU Submitting Information Request regarding the Commission Consultant Survey Report
B1-8	Letter Dated August 2, 2012 – FBCU Submitting comments regarding the addition of a panel member
B1-9	Letter Dated August 3, 2012 – FBCU Submitting Evidence
B1-9-1	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 1 to 2
B1-9-2	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3A – Debt Investment Analyst Reports for FEI
B1-9-3	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Beacon to Credit Suisse
B1-9-4	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Macquarie to UBS

Exhibit No.	Description
B1-9-5	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 4 to 11
B1-9-6	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendices B to J
B1-9-7	**CONFIDENTIAL** Letter Dated August 3, 2012 – FBCU Submitting Evidence CONFIDENTIAL Appendices
B1-10	Letter Dated September 24, 2012 – FBCU Submitting Response to BCPSO IR No. 1
B1-11	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – FBCU
B1-12	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – A. Engen
B1-13	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Concentric
B1-14	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Dr. Vander Weide
B1-15	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – K. McShane
B1-16	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – A. Engen
B1-17	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Concentric
B1-18	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Dr. Vander Weide
B1-19	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – K. McShane
B1-20	Letter Dated September 24, 2012 – FBCU Response to BCUC IR No.1
B1-20-1	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Confidential Response to BCUC IR No.1
B1-21	**CONFIDENTIAL** Letter Dated September 24, 2012 – FBCU Response to Confidential BCUC IR No.1

Exhibit No.	Description
B1-22	Submitted at Procedural Conference Letter Dated October 3, 2012 – FBCU Counsel's Oral Submissions
B1-23	Letter dated October 26, 2012 – FBCU Response to Confidentiality Request
B1-24	Letter dated October 29, 2012 – FBCU Response to BCUC IR No. 2
B1-25	**CONFIDENTIAL** Letter dated October 29, 2012 – FBCU Response to BCUC Confidential IR No. 2
B1-26	Letter dated October 29, 2012 – FBCU Response to BCPSO IR No. 2
B1-27	Letter dated November 2, 2012 – FBCU Comments regarding Confidential Material Access
B1-28	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to AMPC/BC Utility Customers on the Evidence of Dr. Booth
B1-29	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to ICG on the Evidence of Dr. Safir
B1-30	Letter Dated November 23, 2012 – FBCU Submission on Interim Rates Jan 1, 2013
B1-31	Letter Dated November 30, 2012 – FBCU Submitting Witness Panels and Direct Testimony
B1-32	Letter dated December 6, 2012 – FBCU Submitting Rebuttal Evidence
B1-33	Letter dated December 10, 2012 – FBCU Submitting Opening Statement
B1-34	Submitted at Oral Hearing December 12, 2012 – FBCU Written Opening Statement of Counsel
B1-35	Submitted at Oral Hearing December 12, 2012 – FBCU Revised: Exhibit B1-9-6, Appendix H, page 51, Figure 34
B1-36	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 1
B1-37	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 2
B1-38	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 3

Exhibit No.	Description
B1-39	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 4
B1-40	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 5
B1-41	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 6
B1-42	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 7
B1-43	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 8
B1-44	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 9
B1-45	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 10
B1-46	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 11
B1-47	Submitted at Oral Hearing December 14, 2012 – FBCU Filing Testimony of Kathleen C. McShane Tab 2
B1-48	Submitted at Oral Hearing December 17, 2012 – FBCU Undertaking No. 12
B1-49	Submitted at Oral Hearing December 18, 2012 – FBCU Filing Testimony Figures Update
B1-49-1	Letter received January 3, 2013 – FBCU Filing Remaining Chart Updates
B1-50	Submitted at Oral Hearing December 19, 2012 – FBCU Filing 104 page Collection of Documents Used in Cross Examination of Dr. Booth
B1-51	Submitted at Oral Hearing December 21, 2012 – FBCU Filing Compendium of Extracts, First Page Entitled Fair Return for Terasen Gas Inc. (TGI) August 2009
B1-52	Letter received January 3, 2013 – FBCU Undertaking No. 13
B1-53	Letter received January 3, 2013 – FBCU Undertaking No. 14
B1-54	Letter received January 3, 2013 – FBCU Undertaking No. 15
B1-55	Letter received January 3, 2013 – FBCU Undertaking No. 16
B1-56	Letter received January 3, 2013 – FBCU Undertaking No. 17
B1-57	Letter received January 3, 2013 – FBCU Undertaking No. 18

Exhibit No.	Description
B1-58	Letter received January 3, 2013 – FBCU Undertaking No. 19
B1-59	Letter received January 3, 2013 – FBCU Undertaking No. 20
B1-60	Letter received January 29, 2013 – FBCU Undertaking No. 21
B1-61	Letter received January 29, 2013 – FBCU Undertaking No. 22
B1-62	Letter received January 29, 2013 – FBCU Undertaking No. 23
B1-63	Letter received January 29, 2013 – FBCU Undertaking No. 24
B1-64	Letter received January 29, 2013 – FBCU Undertaking No. 25
B1-65	Letter received January 29, 2013 – FBCU Undertaking No. 26
B1-66	Letter received January 29, 2013 – FBCU Undertaking No. 27
B1-67	Letter received January 29, 2013 – FBCU Undertaking No. 28
B1-68	Letter received January 29, 2013 – FBCU Undertaking No. 29
B2-1	**CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated March 14, 2012 – Notice of Registration
B2-2	Letter Dated March 21, 2012 – Corix Submission on the Preliminary Scoping Document
B2-3	Letter Dated May 3, 2012 – Corix Submission on Minimum Filing Requirements
B2-4	Letter Dated May 9, 2012 – Corix Submission regarding Order G-50-12 Appendix A
B2-5	Letter Dated June 8, 2012 – Corix Submission on FBCU Request for Variance
B2-6	Letter Dated August 3, 2012 – Corix Submitting Comments Regarding the Addition of a Panel Member
B2-7	Letter Dated August 3, 2012 – Corix Submitting Evidence
B2-8	Letter Dated September 24, 2012 – Corix Submitting Response to BCPSO IR No. 1
B2-9	Letter Dated September 24, 2012 – Corix Submitting Response to BCUC IR No. 1

Exhibit No.	Description
B2-10	Letter Dated October 18, 2012 – Corix Submitting Response to BCUC IR No. 2
B2-11	Letter Dated November 23, 2012 – Corix Submission regarding A-27
B2-12	Submitted at Oral Hearing December 18, 2012 – Corix Filing Opening Remarks of Counsel for Corix Multi-Utility Services Inc., December 12, 2012
B2-13	Submitted December 24, 2012 – Corix Filing Undertaking Document Titled Before the Florida Public Service Commission
B2-14	Submitted December 24, 2012 – Corix Filing Undertaking Document titled Comparison of Business Risk Adjustments in Cost of Capital Testimony Filed by Ms. Pauline M. Ahern
B2-15	Letter received January 3, 2013 - Corix Filing Response to Undertaking
B3-1	**PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG)** Online Registration Dated March 16, 2012 – Notice of Registration
B3-2	Letter Dated March 21, 2012 – PNG Submission on the Preliminary Scoping Document
B3-3	Letter Dated May 3, 2012 – PNG Submission on Minimum Filing Requirements
B3-4	Letter Dated May 9, 2012 – PNG Submission Regarding Order G-50-12 Appendix A
B3-5	Letter Dated June 8, 2012 – PNG Submission Regarding Variance of the Regulatory Timetable
B3-6	Letter Dated August 3, 2012 – PNG Submitting Comments Regarding the Addition of a Panel Member
B3-7	Letter Dated August 3, 2012 – PNG Submitting Evidence
B3-8	Letter Dated September 24, 2012 – PNG Submitting Response to BCUC IR No. 1
B3-9	Letter Dated September 24, 2012 – PNG Submitting Response to BCPSO
B3-10	Letter Dated September 24, 2012 – PNG Submitting Response to AMPC, BCPSO and CEC
B3-11	Letter Dated November 23, 2012 – PNG Submission Regarding A-27

Exhibit No.	Description
B3-12	Letter Dated November 30, 2012 – PNG Submitting Comments regarding Witness Panels
	OTHER UTILITIES DOCUMENTS
B4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter Dated March 12, 2012 – Notice of Registration
B4-2	Letter Dated March 21, 2012 – BCH Submission on the Preliminary Scoping Document
B4-3	Letter Dated May 3, 2012 – BCH Submission on Minimum Filing Requirements
B4-4	Letter Dated May 9, 2012 – BCH Submission Regarding Order G-50-12 Appendix A
B4-5	Letter Dated June 8, 2012 – BCH Submission Regarding variance of the Regulatory Timetable
B4-6	Letter Dated August 3, 2012 – BCH Submitting Comments Regarding the Addition of a Panel Member
B4-7	Letter Dated November 23, 2012 - BCH Submission Regarding A-27
B4-8	Letter Dated November 30, 2012 – BCH Submitting Comments Regarding Witness Panels
B5-1	**RIVER DISTRICT ENERGY (RDE)** Letter Dated March 12, 2012 – Notice of Registration
	INTERVENER DOCUMENTS
C1-1	**UNION GAS LIMITED (UG)** Letter dated March 5, 2012 – Request for Intervener Status by Patrick McMahon
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated March 15, 2012 – Request for Intervener Status by James Quail
C2-1-1	Letter dated March 20, 2012 – COPE 378 Submitting Intervention Supplementary Comments
C2-2	Letter dated April 19, 2012 - COPE 378 Submitting Updating Consultant details
C2-3	Letter dated June 26, 2012 - COPE 378 Submitting Updating Consultant Information

Exhibit No.	Description
C3-1	**SENTINEL ENERGY MANAGEMENT (SEM)** Online Registration dated March 20, 2012 – Request for Intervener Status by Jim Langley
C4-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated March 20, 2012 Via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C4-2	Letter Dated March 21, 2012 – ICG Submission on the Preliminary Scoping Document
C4-3	Letter Dated May 3, 2012 – ICG Submission regarding the Preliminary Minimum Filing Requirements for Affected Utilities
C4-4	Letter Dated May 9, 2012 – ICG Submission Regarding Order G-50-12 Appendix A
C4-5	Letter Dated June 8, 2012 – ICG Submission regarding Variance of the Regulatory Timetable
C4-6	Letter Dated June 21, 2012 – ICG Submitting Information Request Regarding the Commission Consultant Survey Report
C4-7	Letter Dated August 31, 2012 – ICG Submitting Information Request No. 1
C4-8	Letter Dated October 24, 2012 - ICG Submitting Comments regarding Request for Confidential Information
C4-9	Letter dated November 5, 2012 – ICG Submitting Evidence
C4-10	Letter dated November 6, 2012 – ICG Submitting Confidential Undertakings
C4-11	Letter dated November 30, 2012 – ICG Submitting Responses to Information Request No. 1
C4-12	Letter dated November 30, 2012 – ICG Submission Regarding Exhibit A-27
C4-13	Submitted at Oral Hearing December 12, 2012 – ICG Opening Comments
C4-14	Submitted at Oral Hearing December 14, 2012 – ICG Filing Tab 2 Testimony of Kathleen C. McShane
C4-15	Submitted at Oral Hearing December 17, 2012 – ICG Filing Opening Statement of Dr. Andrew Safir

Exhibit No.	Description
C4-16	Letter dated January 14, 2013 – ICG Submitting Undertakings
C4-17	Letter dated January 25, 2013 – ICG Submitting Dr. Lawrence Booth Undertaking No. 2
C5-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** (previously BC Old Age Pensioner' Organization *et. al*.) **VIA EMAIL -** Letter Dated March 20, 2012 – Request for Intervener Status by Leigha Worth, Tannis Braithwaite and Bill Harper
C5-2	Letter Dated March 21, 2012 – BCOAPO Submission on the Preliminary Scoping Document
C5-3	Letter Dated May 3, 2012 – BCOAPO Submission on Minimum Filing Requirements
C5-4	Letter Dated May 9, 2012 – BCOAPO Submission Regarding Order G-50-12 Appendix A
C5-5	Letter Dated June 8, 2012 – BCOAPO Submission Regarding Variance of the Regulatory Timetable
C5-6	Letter Dated June 22, 2012 – BCOAPO Submitting Information Request Regarding the Commission Consultant Survey Report
C5-7	Letter dated July 23, 2012 – BCOAPO Submitting Notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C5-8	Letter Dated August 3, 2012 – BCPSO Submitting Comments Regarding the Addition of a Panel Member
C5-9	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to Corix
C5-10	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to FBCU
C5-11	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to PNG
C5-12	Letter Dated October 9, 2012 - BCPSO Submitting Information Request No. 2 to FBCU

Exhibit No.	Description
C5-13	Letter Dated October 9, 2012 - BCPSO Submitting Contact Update
C5-14	Letter Dated November 30, 2012 - BCPSO Submission Regarding Exhibit A-27
C5-15	Submitted at Oral Hearing December 17, 2012 – BCPSO Filing Business Spectator Document
C6-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated March 20, 2012 – Request for Intervener Status by Richard Stout and Lloyd Guenther
C6-2	Letter Dated May 2, 2012 – AMPC Submitting Contact Update
C6-3	Letter Dated May 3, 2012 – AMPC Submission on Minimum Filing Requirements
C6-4	Letter Dated May 9, 2012 – AMPC Submission Regarding Order G-50-12 Appendix A
C6-5	Letter Dated June 8, 2012 – AMPC Submission Regarding Variance of the Regulatory Timetable
C6-6	Letter Dated June 22, 2012 – AMPC Submitting Information Request Regarding the Commission Consultant Survey Report
C6-7	Letter Dated August 3, 2012 – AMPC Submitting Comments Regarding the Addition of a Panel Member
C6-8	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU
C6-9	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-9-1	Letter Dated September 23, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Corrected Information Request No. 1 to FBCU on Mr. Engen's Evidence
C6-10	Letter Dated October 22, 2012 - AMPC Filing a Request for Confidential Information
C6-11	Letter Dated October 31, 2012 - AMPC Submitting Comments regarding Access to Confidential Information
C6-12	Letter dated November 5, 2012 – AMPC Submitting Evidence

Exhibit No.	Description
C6-13	Letter dated November 5, 2012 – AMPC Submitting Confidential Undertakings
C6-14	Letter dated November 30, 2012 – AMPC Submission regarding Exhibit A-27
C6-15	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to BCUC
C6-16	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to FBCU
C6-17	Submitted at Oral Hearing December 12, 2012 – AMPC Filing BC Natural Gas Strategy Fueling BC's Economy for the Next Decade and Beyond
C6-18	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 17d
C6-19	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 21 i
C6-20	Submitted at Oral Hearing December 17, 2012 – AMPC filing Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding Direct Testimony of James M. Coyne
C6-21	Submitted at Oral Hearing December 18, 2012 – AMPC Filing Witness Aid Prepared by BC Utilities Customers
C6-22	Submitted at Oral Hearing December 19, 2012 – AMPC filing Dr. Booth's Opening Statement
C6-23	Letter dated January 18, 2013 – AMPC Submitting Dr. Booth Undertaking No. 1
C6-24	Letter Dated February 14, 2013 – AMPC Submitting Extension Request
C7-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter Dated March 20, 2012 – Request for Intervener Status by Christopher Weafer
C7-2	Letter Dated May 9, 2012 – CEC Submission Regarding Order G-50-12 Appendix A
C7-3	Letter Dated June 8, 2012 – CEC Submission Regarding variance of the Regulatory Timetable

Exhibit No.	Description
C7-4	Letter dated June 25, 2012 – CEC Submitting Information Request Regarding the Commission Consultant Survey Report
C7-5	Letter Dated August 3, 2012 – CEC Submitting Comments Regarding the Addition of a Panel Member
C7-6	Letter dated November 9, 2012 – CEC Submitting Confidential Undertakings

INTERESTED PARTY DOCUMENTS

D-1	**AT BUSINESS CONSULTING (ATB)** Online Registration dated May 9, 2012 – Request for Interested Party Status by Anastasios Tsalamandris

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
	Capital structure (debt/equity ratio)	60/40 (actual)	60/40 (actual)	60/40 (actual; proposed)		60/40 (actual)	Deemed 60/40	Deemed 60/40	Deemed 60/40
	Equity Risk Premium	N/A	0 bps (approved)	50 bps (proposed)		50 bps (approved)	50 bps (approved)	100 bps (approved)	50 bps (approved)
1	Technology risk/system performance risk associated with chosen technologies	Natural Gas: proven technology	Geo-exchange loop field system and heat recovery with high efficiency natural gas boilers equipment	Recovered waste heat from TELUS Data Centre with peaking and redundant backup heat supplied by Centre Heat Distribution Ltd.: low risk	Slightly higher for PCI / TG than FEI NG	High efficiency condensing boilers: proven technology; Ground source heat pumps; less established technology	Natural gas boilers proven technology	Biomass Gasification innovative technology; Natural Gas boilers; proven technology (while DGE not yet on biomass, the Commission approved the technology)	Natural Gas: boiler: proven technology

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ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
2	Fuel Risk cost and availability	Natural gas: Low-medium	Low risk: free energy from ground and heat recovery, but cost risk for electricity used to operate heat pumps and TES equipment, and for natural gas for supplementary heat and peaking	Data Centre that supplies waste heat is assumed to be available throughout the 20 year term of the analysis: low risk Data Centre ceases operation	Lower for PCI / TG than FEI NG	Natural gas and electricity: Low-medium; Heat from ground: low (some energy cost risk in electricity costs to operate GSHPs)	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant	Biomass: medium-high; natural gas; low-medium	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant
3	Customer Base (e.g., diversity, certainty, growing, declining)	Established and diverse customer base but very slow growth	Greenfield utility four types of customers	Not large customer base or significant diversity: low risk	Higher for PCI / TG than FEI NG (NG has much greater diversity)	Established customer: low risk	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out
4	Default risk of customer	Minimal	Minimal	Minimal	Similar for PCI / TG as for FEI NG	Minimal as SD has budget constraints as well	Minimal	Minimal	Minimal

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
5	Property development risk	Medium to high: there are competing energy options	Low risk: all customers bound by agreement	Majority of tenants committed but customers can still leave: low risk	Lower for PCI / TG than FEI NG	None, as not a new development	Low: phased approach to capital deployment	High: build first approach to capital deployment	Low: phased approach to capital deployment
6	Developer / customer connection risk	Medium to high: due to building stock changes and competitive energy sources	Low Risk: customers will connect on occupancy	Low Risk: customers will connect on occupancy	Lower for PCI / TG than FEI NG	Low, as one known customer with existing sites	Low: mandatory connection	Low: mandatory connection	Low: mandatory connection
7	Load Forecast Uncertainty	Minimal in the short term, as mature utility with deferral account; somewhat higher in the long term	Inherent uncertainty in load forecast	FAES proposes to take forecast risk on actual energy throughput versus forecast for 5 year period: Low-medium	Higher for PCI / TG than FEI NG	Low, as established energy load	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
8	Utility size	Large and mature utility	Project is carried out by a separate corporate entity, Small development specific utility.	Project is carried out by separate corporate entity, Small development specific utility.	Higher for PCI / TG than FEI NG	Project is carried out by separate corporate entity	Small development specific utility	Small development specific utility	Small development specific utility
9	Initial construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
10	Future Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
11	Operating cost risk	Minimal as revenue requirement application to recover costs	Minimal as mechanism in place to recover costs	Low-medium risk: as deferral accounts do not cover all O&M variances between forecast and actual	Higher for TG, similar for PCI relative to FEI NG	Minimal as mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
12	Public Acceptance Risk	Medium as natural gas is an established and widely used technology but public perceives it as less than clean	Low as seen as green alternative	Low	Lower for PCI / TG than FEI NG	Low as seen as green alternative	Low as seen as a green alternative	Low as gasification technology part of approval process for the development and already selected at the time of the CPCN application	low as seen as a green alternative
13	Fixed/Variable rate design	15% fixed/85% variable	~~100% variable~~ Rate Design Not Approved	100% variable (volume rate)	Higher for TG, relative to FEI NG PCI Rate Design not Approved	100% variable	60% fixed/40% variable	50% fixed/50% variable	66% fixed / 34% variable

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
14	Levelized approach to rates	No	~~Only in first three years then transition to cost of service~~ Rate Design not Approved	The rates charged for the first five years have been mutually agreed upon using a benchmark based on BC Hydro RIB Step 1 and Step 2	Slightly higher for TG, relative to FEI NG PCI Rate Design Not Approved	No, transitional market rate and deferral account	Yes	Yes	Yes
15	Financial risk	Low-medium: appropriate standalone financing structure for capital markets	Medium (similar to DSD)	Forecast risk and rates fixed for first five years (other than one-time adjustment for GCOC changes) impacts financial risk: medium risk justifies 50 bps on FEI utility benchmark	Higher for PCI / TG than FEI NG	Medium	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
16	Competitive challenges	Competitive with electricity and competition from alternative energy providers	Other TES providers and electricity	Other TES providers and electricity	Lower for PCI / TG than FEI NG	Other TES providers and electricity	Other utilities and electricity	Other utilities and electricity	Other utilities and electricity
17	Provincial climate change and energy policies	Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use.	Favourable government policies	Favourable government policies	Lower for PCI / TG than FEI NG	Favorable govt. policies	Favourable govt. policies	Favourable govt. policies	Favourable govt. policies
18	Regulatory uncertainty	Low to medium: uncertainty exists for service offerings within the natural gas class of service.	Medium risk: New, uncertainty, scrutiny and not streamlined Rate Design Denied as Applied	Medium risk: New, uncertainty, scrutiny and not streamlined	Higher for PCI / TG than FEI NG	Medium risk: new, uncertainty, scrutiny and not streamlined	Medium risk: New, uncertainty, scrutiny, alternative energy centre not yet approved	Medium risk: New, uncertainty, scrutiny	Medium risk: New, uncertainty, scrutiny

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
19	Business Development Risk	Minimal	Low – deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1.) [Shareholder ultimately at risk for the TESDA]	FAES has agreed to purchase the TGTES from the Partnership upon commissioning for actual construction cost of $7.9 million up to a maximum of 30% above the $7.9 million estimate.	Higher for PCI / TG than FEI NG	Low: deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) (Shareholder ultimately at risk for the TESDA)	High as part of overhead cots	High as part of overhead cots	High as part of overhead cots

COST OF CAPITAL ESTIMATION MODELS AND KEY INPUTS

DISCOUNTED CASH FLOW MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
McShane	Constant Growth	12 US utilities	4.9% - Average of consensus earnings forecasts from Bloomberg, Reuters, ValueLIne and Zacks.	9.3	McShane Evid, Table 30, p. 113; App. C, and Schedule 19
	Constant Growth	5 Can utilities (incl. Fortis Inc.)	7.5% - Reuters L-T EPS forecasts	11.0	McShane Evid, Table 30, p. 113 and Schedule 22
	Sustainable Growth	12 US Utilities	4.4% - Avg of sustainable growth rates for US utilities derived from Value Line forecasts of ROEs, earnings retention rates and earnings growth from external financing.	8.7	McShane Evid, Table 30, p. 113 and Schedule 20
	Three Stage Model	5 Can utilities (incl. Fortis Inc.)	Stage 1 (yrs 1-5) - Reuters L-T EPS forecasts: 7.5% Stage 2 (yrs 6-10)- Avg of stages 1 and 3: 5.9% Stage 3 (yrs 11+)-GDP growth: 4.3%	8.6	McShane Evid, Table 30, p. 113 App. C and Schedule 23
	Three Stage Model	12 US utilities	Stage 1 (yrs 1-5) - Avg of all EPS forecasts: 4.9% Stage 2 (yrs 6-10) - Avg of stages 1 and 3: 4.9% Stage 3 (yrs 11+) - GDP growth: 4.9%	9.2	McShane Evid, Table 30, p. 113 and Schedule 21
	Mid-point of range	Canadian sample		9.8	McShane Evid. p. 113
	Mid-point of range	Both samples		9.4	McShane Evid. p. 113
			Bare bones Cost of Equity estimated at 9.4% and add Financing Flexibility Adjustment of 0.5%	9.9	

...**DCF MODELS**

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Vander Weide	Quarterly DCF model	Comprehensive group of 32 US utilities	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.8	VdW Evid, p. 28 – 30 and Exhibit 6
		Small group of 19 US utilities (subset of large group)	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.5	VdW Evid, p. 28 – 30 and Exhibit 7
			Bare-bones cost of equity for the Comprehensive Model 9.8% plus Financing Flexibility	10.3	
			Bare-bones cost of equity for the Small Utilities Model 9.5% plus Financing Flexibility	10.0	
			Summary of results from DCF	10.15	
Booth		All of Canadian market	Growth rate range 4.7% - 6.1% based on multiplying corporate Canada ROEs since 1987 times retention rates.	9.3	Booth Evid., p. 94 & App D, p. 9-10
		US market – S&P 500	Growth rate range of 6.79% - 7.97% based on multiplying the average and median values respectively for S&P 500 ROEs since 1977 times the current dividend yield	Calculated range: 8.93-10.01. Adjusted range: 9.5-10.5	Booth Evid., App D, p. 10-13 (Note disc. of analyst forecasts at p. 14-17.)

...**DCF MODELS**

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Safir	Two-stage model	Canadian Sample - 5 Can. utilities (incl. Fortis)	Stage 1 (analyst forecasts)- 7.49%; Stage 2 (GDP growth) – 4.49% Weighted average (33/67): 5.49%	8.99	Safir Evid, p. 24-26, and Schedule 3
	Two-stage model	US Sample – 18 US utilities	Stage 1 (analyst forecasts) - 5.50%; Stage 2 (GDP growth) – 4.57% Weighted average (33/67): 4.88%	8.86	Safir Evid,p. 24-26, and Schedule 4
			ROE Adjusted by Flotation Costs at 5% for Canadian sample	9.46	Safir Evid. p. 26
			ROE Adjusted by Flotation Costs at 5% for US sample	9.33	Safir Evid. p. 26

CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	See her Risk-Adjusted Equity Risk Premium Model					
Vander Weide	N/A – Vander Weide recommends placing no weight on CAPM results	2.95% forecast yield to maturity on L-C bonds	6.6% - Ibbotson SBBI estimate of risk premium on market portfolio – diff. between arithmetic mean return on S&P 500 vs. income return on 20-year Treasury bonds. (1937-2012)	0.73 – Average Value Line beta for his large proxy US utility group.	8.27 (including financial flexibility)	Vander Weide Evid, pp. 38-44; Exhibits 12 to 15
				0.92 – historical ratio of the average utility risk premium to the S&P risk premium	9.52 (including financial flexibility)	
Booth	Simple CAPM estimate	3.00% (Base adjusted LTC forecast)	Range: 5.0 – 6.0%	Range: 0.45-0.55	Range: 5.75-6.80, including 0.50 flotation cost allowance	Booth Evid, p. 74 & 75; App. B (MRP), p. 16, App. C (beta est), pp. 10-14
	Adjusted CAPM (Simple CAPM plus 0.40 for credit spread and 0.80 for Operation Twist.	3.80% (Base adjusted LTC forecast)	Same as above	Same as above	Range: 6.95 to 8.00 (2013) 7.00 -8.00 Including flotation cost allowance	Booth Evid, p. 85, 93-94 (adjustments); other values same as above.
				Point estimate for CAPM	7.5	Booth Evid. p. 95

…CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
Safir	Canadian CAPM	4.00%	5.96% (Total mkt. return minus the est annual long bond income return (both 1924-2010)	Adjusted beta: 0.36 (weighted 0.67 raw + 0.33 mkt tendency) Calculated raw beta (Sched 1): 0.25 Long-run mkt tendency beta (Schaeffler & Weber survey): 0.58	6.15	Safir Evid. p. 12-15 and Schedule 1
	US CAPM	4.50%	6.62% (Total mkt. return minus the est annual long bond income return (both 1926-2011)	Adjusted beta: 0.48 (weighted 0.67 raw + 0.33 market tendency) Calculated raw beta (Schedule 2): 0.43 Long-run market tendency beta (Schaeffler & Weber survey): 0.58	7.68	Safir Evid. p. 18 and Schedule 2
				Adjusted by flotation cost allowance of 0.32% for the Canadian ROE estimate	6.47	Safir Evid. p. 12
				Adjusted by flotation cost allowance of 0.40% for the US ROE estimate	8.08	Safir Evid. p. 18

EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	Risk-adjusted ERP (variant of CAPM)	4.0% (forecast 30 yr Long-Can bond yield)	7.25-7.5% (based on bond income returns < 8.0%; table 12, pp. 82, 98 of her evid)	0.65-0.70 adjusted (0.65 based on Bloomberg adjusted betas for 5 Can utilities or raw beta for TSX utilities index adjusted per Bloomberg (.67 raw+0.33; see McShane evid. p. 97. For upper end of range see table 21, p. 98)	Range: 8.9-9.1% Est. 9.0%	McShane Evidence, p. 98
	DCF Based ERP Models: 1998-2012 Q1 US Sample					
	Constant Growth – Single variable (L-C bond rate)	4.0% (forecast 30 yr L-C yield)	5.7% at 4.0% risk free rate (see table 22, p. 100)	N/A	9.7%	McShane evid. p. 99-101
	3-stage growth - single variable	4.0%	5.7 or 5.8% at 4.0 risk free rate (apparent inconsistency between tables 24 and 25)	N/A	9.7	McShane evid p. 99-105
	Constant Growth – two variable (L-C bonds and 30 year A-rated utility yield spreads)	4.0%	5.5%	N/A	9.5	McShane evid at pp. 102-105, esp. table 25.
(cont….)	3-stage growth – two variable	4.0%	5.6%	N/A	9.6	McShane evid at pp. 102-105, esp. table 25.

…**EQUITY RISK PREMIUM MODELS**

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane (cont. from previous page)	*DCF Based ERP Models*: 1998-2012Q1 US Sample (continued from previous page)					
	Quarterly US utility ROE's as proxy for utility cost of equity – single variable	4.0%	6.2%		10.2 (McShane gives no weight)	McShane evid at pp. 102-105, esp. table 25
	Quarterly US utility ROE's– two variable	4.0%	6.1%		10.1 (no weight)	McShane evid at pp. 102-105, esp. table 25
	Constant Growth over A-rated bond	5.35% (4.0% L-C bond yield + 135 bp)	4.0		9.4	McShane evid at p. 105, table 26
	3-stage growth over A-rated bond	5.35% (as above)	4.2		9.6	McShane evid at p. 105, table 26
	Allowed ROEs over A-rated bond	5.35% (as above)	4.8		10.2 (no weight)	McShane evid at p. 105, table 26
(cont…)	Summary of results DCF based results	4.0%% (f'cast L-C bond yields) or 5.35% (A-rated utility bond yields	Range of regression results		9.4 – 9.7	McShane Evid. p. 106
			Bare bones Cost of Equity (mid-point)		9.6	

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Equity Returns	Bond Inc. Returns	Utility Risk Premium	Change in Bond Yield/Ret	Change in Util Risk Pr.	Utility Equity Risk	ROE est. (%)	References
McShane (cont. from previous page)	Historic Utility ERP- Can utilities (1956-2011)	4.0%	12.1%	7.3%	4.8%	-3.3%	+1.6%	6.4%	10.5 (based on all 3 Historic Utility ERP tests)	McShane Evid. pp. 106-108
	Historic Utility ERP- US Gas Utilities (1947-2011)	4.0%	11.9%	5.9%	6.0%	-1.9%	+1.0%	7.0%		McShane Evid. pp. 106-108
	Historic Utility ERP- US Elec Utilities (1947-2011)	4.0%	11.0%	5.9%	5.1%	-1.9%	+1.0%	6.2%		McShane Evid. pp. 106-108
	Summary of All Risk Premium Tests	Risk-Adjusted Equity Market							9.0	McShane Evid p. 109, table 29
		DCF-based							9.6	
		Historic Utility							10.5	

Vander Weide (cont…)			Stock Returns	Avg Bond Yields	Risk Premium	Expected bond yield		
	Ex-Post Risk Premium	S&P/TSX Utilities: 1956-2011	11.99%	7.33%	4.7%	N/A	N/A	Vander Weide Evid, pp. 32-35, 44; and Exhiibits 8 & 9
		BMO Utilities: 1983-2011	16.01	7.24	8.8%	N/A	N/A	
		Average risk premium of the two samples			6.7%	2.95%	10.15 (rounded to 10.2% (incl. 0.5% flotation	

…EQUITY RISK PREMIUM MODELS

Analyst	Model sub-Type	Sample Group and Period	DCF Growth rate	Risk Prem.	Risk Free Rate	Roe est. (%)	References
Vander Weide (cont. from previous page)	Ex-Ante Risk Premium	Natural Gas group selected from S&P nat. gas companies	DCF growth rate and analysis by individual company from I/B/E/S forecast of earnings growth for each month. (Exhibits 10 & 11)	8.0%	2.95%	11.5 (incl flotation)	Vander Weide Evid. pp. 35-38 and App. 3, Exhibits 10, 11 and 24
		Moody's group of 24 Electric utilities.		7.5%	2.95%	11.0 (incl flotation)	
Booth	N/A						
Safir	N/A						

COMPARABLE EARNINGS TESTS

Analyst	Model sub-Type	Sample Group and Period	ROE est. (%)	References
McShane	Book-value based	21 Canadian unregulated companies: 2004-2011 (incl downward adjustments of 125 to 150 bps)	Range: 11.0-12.0 Est: 11.5	McShane Evid, pp. 113-117, 119 and App E.
Vander Weide	N/A		N/A	
Booth	Book-value based	Corporate Canada (Statistics Canada reported earnings): 1987-2011, and TSX composite for the same period	Market ret: 9.3	Booth Evid. p. 93 and App. E, Schedule 2
Safir	Market-value based	Canadian sample: same 21 Canadian Companies as used by McShane: 2004-2011	6.85	Safir Evid. pp. 28-35 and Schedules 5 and 6
	Market-value based	US Sample: 31 US companies in the consumer goods, industrial goods or service sectors using same selection critiera as McShane used for her Canadian sample: 2004-2011.	5.81	
	Weighted average giving Canadian results twice the weight of the US results		6.50	

SUMMARY OF ROE RECOMMENDATIONS

Analyst	Method	Model Sub-Type	'Bare-bones' Cost of Equity"	Financing Flexibility Adjustment	ROE est. (%)	References
McShane	DCF		9.4%	0.50%	9.9	McShane Evid. pp. 6 and 119
	Risk Premium	Risk-Adj Equity Mkt	9.0%	0.50%	9.5	
		DCF-based	9.6%	0.50%	10.1	
		Historic Utility	10.5%	0.50%	11.0	
	Comp. Earning		N/A	N/A	11.5	
VanderWeide	DCF		9.5%	0.5%	10.15	Vander Weide Evid. p. 44 and Exhibit 7
	CAPM	Calulates ROEs (incl. flotation allowance) of 8.27% and 9.52% but gives the CAPM results no weight			N/A	Vander Weide Evid. p. 44 and Exhibits 12 and 13
	Risk Premium	Ex-Post RP	9.65%	0.50%	10.15 (10.2)	Vander Weide Evid. pp. 35, 38 and 44, and Exhibits 8, 9, 10, 11 and 24
		Ex-Ante RP (average of Natural Gas and Elec. Samples	10.75%	0.50%	11.25	
Booth	Discounted Cash Flow	All of Canadian market	9.28% for the market as a whole		N/A	Booth Evid. p. 93-94 and App. D, pp. 9-10
		US market – S&P 500	9.5% - 10.5% for the US market		N/A	
	CAPM	Adjusted for credit spread and Operation Twist	6.95-7.50%	0.50%	7.50	Booth Evid. pp. 93-94
	Comp. Earning	Market Returns	9.3% for Corporate Canada (StatsCan)		N/A	Booth Evid, p. 93-94; App. E, pp. 2-7
Safir	DCF	Canadian Sample	8.99%	0.47%	9.46	Safir Evid, p. 26
		US Sample	8.86%	0.47%	9.33	
	CAPM	Canadian Sample	6.15%	0.32%	6.47	Safir Evid. p. 12
		US Sample	7.68%	0.40%	8.08	Safir Evid. p. 18
		Weighted average	N/A	N/A	7.01	Safir Evid, p. 19
	Comp Earning	Market value based results; wighted avg of Can and US results			6.50	Safir Evid. p. 33

LIST OF ACRONYMS

AAM	Automatic Adjustment Mechanism
AECO	Alberta's gas trading price
AES	Alternative Energy Services
AMPC	Association of Major Power Consumers
AUB	Alberta Utilities Commission
B	Beta
BA	Bankers' Acceptances
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCUC	British Columbia Utilities Commission
BC Utility Customers	Collectively AMPC, BCPSO, CEC
bps	Basis points
CAPM	Capital Asset Pricing Model
CDOR	Canadian Dealer Offered Rate
CEC	Commercial Energy Consumers of B.C.
CEA	Clean Energy Act
Concentric	Concentric Economic Advisers
CPCN	Certificate of Public Convenience and Necessity
DCF	Discounted Cash Flow
ERP	Equity Risk Premium
FRS	Fair Return Standard
FBCU	FortisBC Utilities
Fl PUC	Florida Public Service Commission

LIST OF ACRONYMS

GCOC	Generic Cost of Capital
GJ	Gigajoule
ICG	Industrial Customers Group of FortisBC Inc.
LCBF	Long Canada Bond Forecast
NEB	National Energy Board
O&M	Operation and Maintenance
PBR	Performance Based Ratemaking
PNG	Pacific Northern Gas
PRMP	Price Risk Management Plan
OEB	Ontario Energy Board
ROE	Return on Equity
r_m	Expected return on the market
r_f	Risk free rate
$r_m - r_f$	Market risk premium
r_e	Opportunity cost of equity
Régie	Régie de l'Energie
TES	Thermal Energy Services
Terasen, TGI	Terasen Utilities, Terasen Gas Inc.
UCA	Utilities Commission Act
UPC	Use Per Customer

YEC-YECL-14

Reference: Section 8 – Return on Rate Base – Common Equity Ratio

Request:

(a) Please confirm that forecast common equity ratio is 43.61% for 2013, 43.66% for 2014 and 43.70% for 2015.

(b) Please explain the reason for increase in common equity ratio from 40.65% in 2012 to 43.61% in 2013.

(c) Please confirm that based on Schedule 8.1 the mid-year balance of common equity forecast to increase from $25.740 million in 2012 actual to $42.860 million in 2015, i.e. increase of $17.120 million over three years. Please provide forecast sources for this additional equity amount (parent company equity injections, retained earnings or other).

(d) Please update Schedule 8.1 by using 40% equity ratio and discuss impacts to the YECL to provide services to its customers.

(e) Please outline and explain in detail any changes in YECL's risk profile since the 2008/2009 GRA that would warrant an increase in equity ratio from 40%.

(f) Please explain the impact that the number of deferral accounts (Whitehorse Copper Tailings Sales Uncertainty, Purchased Power Flow Through, Depreciation Parameters, ROE and Defined Benefit Pension Plan proposed in the current application would have on YECL's risk profile.

Response:

(a) Yukon Electrical can confirm that the forecast common equity ratio is 43.61% for 2013, 43.66% for 2014 and 43.70% for 2015. However, when no cost capital is excluded, the forecast common equity ratio is 44.0% for 2013-2015. Please refer to YEC-YECL-14(a) Attachment 1 for a copy of Schedule 8.1 showing the equity ratio not including no cost capital.

(b) Yukon Electrical has requested an increase in equity ratio from 40% to 44% as part of its 2013-2015 GRA. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

(c) Confirmed. The source of the additional equity amount will be parent company equity injections and retained earnings.

(d) Please refer to YEC-YECL-14(d) Attachment 1 for Schedule 8.1 updated for a 40% equity ratio. The requested 44% common equity ratio, based in part on a respect of the stand-alone principle, is required for Yukon Electrical to contribute its fair share towards the maintenance of CU Inc.'s A credit rating. As Yukon Electrical's debt mirrors the debt of CU Inc., Yukon Electrical's customers benefit from the low interest rates obtained by the A rated CU Inc.

(e) Please refer to YUB-YECL-31 addressing changes to Yukon Electrical's risk profile since the 2008/2009 GRA. Further, the increase in common equity ratio is based on the following increases in common equity ratios since Decision 2009-02:

BCUC's benchmark utility common equity ratio increased from 35.01% to 38.5%;

Northland Utilities (Yellowknife)'s common equity ratio increased from 39.57% to 43.5%; and

Northland Utilities (NWT)'s common equity ratio increased from 40% to 44%.

As noted in part (b) of this response, these changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility.

(f) As detailed below, there is no material change to Yukon Electrical's risk profile as a result of the deferral accounts requested as part of this 2013-2015 GRA Application as compared to the risk profile reviewed as part of the 2008/2009 GRA.

Whitehorse Copper Tailings – No industrial customers were forecast as part of Yukon Electrical's 2008/2009 GRA. The requested deferral therefore results in Yukon Electrical's risk profile remaining constant.

Purchased Power Flow Through – There is no change requested in this Application from the previously YUB approved deferral.

Depreciation Parameters – As detailed in Section 7 of its Application, the intension of Yukon Electrical's requested deferral is, to the extent possible, permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, the purpose of deferral is not to address Yukon Electrical's risk profile.

ROE - The proposed AAM and ROE deferral does not reduce Yukon Electrical's risk profile. BCUC is re-instituting an AAM as it has the potential to contribute to regulatory efficiency, and did not note in its decision any impact the AAM formula has on the risk profile of the benchmark utility.

Defined Benefit Pension Plan – In its 2008/2009 GRA, Yukon Electrical did not request a Defined Benefit Pension Plan deferral as its funding requirements for the test period were known based on the December 31, 2006 Actuarial Valuation. For purposes of this Application, the funding requirements for 2013, 2014 and 2015 are not known. The requested deferral therefore results in Yukon Electrical's risk profile remaining constant.

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Balance Excluding No Cost Capital	Ratio Excluding No Cost Capital	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**								
27	Long-Term Debt	S.8.3 L.23	40,150	55.52%	40,150	56.00%	40,154	5.99%	2,404
28	Common Stock		31,540	43.61%	31,540	44.00%	31,544	9.21%	2,904
29	No Cost Capital	S.8.4 L.8	632	0.87%			632	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,322	100.0%	71,690	100.0%	72,329	7.34%	5,308
31	**2014 Test Period**								
32	Long-Term Debt	S.8.3 L.48	47,950	55.58%	47,950	56.00%	47,835	5.84%	2,793
33	Common Stock		37,670	43.66%	37,670	44.00%	37,579	9.21%	3,462
34	No Cost Capital	S.8.4 L.8	651	0.75%			649	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,271	100.0%	85,620	100.0%	86,063	7.27%	6,255
36	**2015 Test Period**								
37	Long-Term Debt	S.8.3 L.73	54,550	55.62%	54,550	56.00%	53,845	5.77%	3,105
38	Common Stock		42,860	43.70%	42,860	44.00%	42,306	9.21%	3,898
39	No Cost Capital	S.8.4 L.8	670	0.68%			661	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	98,080	100.0%	97,410	100.0%	96,812	7.23%	7,003

Schedule 8.1

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2008 Actual**						
2	Long-Term Debt	S.8.2 L.19	24,575	56.81%	26,100	6.97%	1,819
3	Common Stock		17,994	41.59%	19,110	7.03%	1,344
4	No Cost Capital	S.8.4 L.8	693	1.60%	735	0.00%	-
5	Total	S.8.5 L.21 S.1.1 L.15	43,262	100.0%	45,946	6.88%	3,163
6	**2009 Actual**						
7	Long-Term Debt	S.8.2 L.42	27,650	57.34%	28,166	6.73%	1,895
8	Common Stock		19,866	41.20%	20,236	11.35%	2,296
9	No Cost Capital	S.8.4 L.8	702	1.45%	715	0.00%	-
10	Total	S.8.5 L.21 S.1.1 L.15	48,217	100.0%	49,116	8.53%	4,191
11	**2010 Actual**						
12	Long-Term Debt	S.8.2 L.63	29,950	57.27%	28,649	6.58%	1,884
13	Common Stock		21,682	41.46%	20,740	10.54%	2,187
14	No Cost Capital	S.8.4 L.8	666	1.27%	637	0.00%	-
15	Total	S.8.5 L.21 S.1.1 L.15	52,298	100.0%	50,026	8.14%	4,071
16	**2011 Actual**						
17	Long-Term Debt	S.8.2 L.85	32,450	57.36%	30,062	6.42%	1,931
18	Common Stock		23,472	41.49%	21,745	10.74%	2,335
19	No Cost Capital	S.8.4 L.8	649	1.15%	601	0.00%	-
20	Total	S.8.5 L.21 S.1.1 L.15	56,571	100.0%	52,408	8.14%	4,266
21	**2012 Actual**						
22	Long-Term Debt	S.8.2 L.107	36,950	58.35%	35,031	6.16%	2,158
23	Common Stock		25,740	40.65%	24,403	10.18%	2,484
24	No Cost Capital	S.8.4 L.8	631	1.00%	598	0.00%	-
25	Total	S.8.5 L.21 S.1.1 L.15	63,321	100.0%	60,033	7.73%	4,642

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Return on Rate Base
($000s)

Schedule 8.1

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
26	**2013 Test Period**						
27	Long-Term Debt	S.8.3 L.23	43,014	59.48%	43,018	5.88%	2,529
28	Common Stock		28,676	39.65%	28,679	9.21%	2,641
29	No Cost Capital	S.8.4 L.8	632	0.87%	632	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.15	72,322	100.0%	72,329	7.15%	5,170
31	**2014 Test Period**						
32	Long-Term Debt	S.8.3 L.48	51,372	59.55%	51,248	5.71%	2,926
33	Common Stock		34,248	39.70%	34,166	9.21%	3,147
34	No Cost Capital	S.8.4 L.8	651	0.75%	649	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.15	86,271	100.0%	86,063	7.06%	6,073
36	**2015 Test Period**						
37	Long-Term Debt	S.8.3 L.73	58,446	59.59%	57,691	5.69%	3,280
38	Common Stock		38,964	39.73%	38,460	9.21%	3,542
39	No Cost Capital	S.8.4 L.8	670	0.68%	661	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.15	98,080	100.0%	96,812	7.05%	6,822
41	**2008 GRA Approved**						
42	Long-Term Debt	S.8.2 L.126	26,621	59.11%	27,243	6.87%	1,870
43	Common Stock		17,747	39.41%	18,162	9.08%	1,649
44	No Cost Capital	S.8.4 L.8	669	1.49%	685	0.00%	-
45	Total	S.8.5 L.21 S.1.1 L.15	45,037	100%	46,090	7.64%	3,519
46	**2009 GRA Approved**						
47	Long-Term Debt	S.8.2 L.148	29,730	59.17%	29,276	6.60%	1,934
48	Common Stock		19,820	39.45%	19,517	8.92%	1,741
49	No Cost Capital	S.8.4 L.8	695	1.38%	684	0.00%	-
50	Total	S.8.5 L.21 S.1.1 L.15	50,245	100%	49,478	7.43%	3,675

YEC-YECL-15

Reference: Section 9 – Capital Additions – Capital Additions General

Request:

(a) Describe the system planning criteria (i.e. decision making process for diesel plant replacement, distribution upgrades and other projects included in this GRA) used to develop YECL's capital plans.

(b) Please describe the age and condition assessments which lead to YECL's conclusion that distributions assets need to be upgraded.

(c) Please provide a copy of YECL's capitalization policy.

(d) Please confirm that under International Financial Reporting Standards (IFRS) entities are not permitted to charge projects for equity returns and use debt only rate for AFUDC. If this is confirmed please explain why YECL is proposing to use both an equity and debt components for AFUDC rate.

(e) Does YECL have deferred cost or deferral account accounting policies? If so please provide copies of the policies. Please explain how the deferred accounting policy works, including:

  (i) which type of cost to be deferred;

  (ii) who has the authority for decision to defer, close and amortize YECL deferred costs

  (iii) how the amortization period is determined

(f) Please provide a continuity schedule for each category of deferred cost for YECL for the years 2010 to 2015 showing additions, close-outs, work in progress and amortizations.

(g) Identify which capital projects included in GRA application, both actual and forecast, are improving reliability and provide an explanation for how they improve reliability.

(h) Please provide a continuity schedule for YECL of Contributions in Aid of Construction or customer contributions for the years 2010 to 2015 by project segregating additions, amortizations and other adjustments.

Response:

(a) Distribution projects are identified based on deficiencies; issues and needs are brought forward as a result of inspections, system monitoring and reviews of the generation and distribution system. Planning criteria for generators also includes a review of operating hours. These issues and needs are reviewed at regular meetings involving the Operations and Engineering departments. The projects are then approved or not pending further information or alternatives. Once the project is approved they are prioritized as "A" or "B" projects and are scheduled into Yukon Electrical's capital plans.

(b) The Distribution system is inspected on an annual basis through the system inspection program. Any components that are deficient or requiring corrective action are recorded and tracked to completion. Condition assessments are also recorded and tracked to completion through our test and treat program, ground rod testing, clearance checks, brushing and hazard tree patrols, infrared scanning, daily interaction with the distribution system and as a result of unplanned outages and the causation analysis. Generation components are also inspected. The generating units and associated equipment is monitored to ensure the operating hours are accurately tracked. A combination of equipment condition assessments, performance and recommended operating hours will dictate the replacement of the generation equipment.

(c) Please refer to YEC-YECL-15(c) Attachment 1 for a copy of ATCO Electric's capitalization policy which is also used by Yukon Electrical.

(d) Confirmed. Consistent with past practice and consistent with its parent, ATCO Electric, as well as the Northland companies in the NWT, Yukon Electrical has maintained the existing Board-approved methodology for calculating AFUDC that includes both equity and debt components for the AFUDC rate. For the purpose of preparing its financial statements in accordance with IFRS, Yukon Electrical capitalizes borrowing costs using a debt-only rate.

(e) Yukon Electrical does not have a deferred cost or deferral account accounting policy as, under IFRS, deferred costs such as study costs and expenses related to a deferral account are required to be expensed in the year incurred.

For regulatory purposes, where Yukon Electrical believes that there is value to customers over a period greater than one year, such is the case with the

deferred study costs related to the Watson Lake Bi-Fuel project, Yukon Electrical requests the Board's approval to recover such costs over a period of time that corresponds to the period of time over which the benefits occur.

(f) Please refer to Schedule 8.8 of the Application for a continuity schedule of each deferred charge for the period of 2008 through 2015.

(g) All capital work that is either replacing like for like, upgrading or adding to the system will inherently improve reliability, since it will be newer equipment and built to today's standards. Certain projects have been justified primarily on reliability, while others have been justified by other drivers such as safety. Yukon Electrical conducted a review of its forecast improvement projects for the period 2013 to 2015 and determined that all projects improved reliability in some way or another. The explanations provided in Yukon Electrical's Application, Section 9, provide information on why a project is to be undertaken and outlines reliability benefits on a project by project basis.

(h) Please refer to YEC-YECL-15(h) Attachment 1.

ATCO ELECTRIC LIMITED ACCOUNTING POLICY MANUAL	***Capitalization***
	Date: December 2010 **Number:** D.1.a
PREPARED BY: K. Trunzo	**APPROVED BY:** D. Freedman

This policy is intended to describe the accounting treatment involved in the capitalization of fixed assets. Immediately following this policy, additional policies can be found which cover more specific topics.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric now applies certain accounting policies to its publicly released financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

Fixed Asset

A unit of property which can be physically identified and has a useful life in excess of one year. The value of the assets should include any non-recurring costs which are relative to its creation. Included in the cost of a fixed asset would be materials, direct and indirect labour, expenses, fringe benefits and an appropriate proportion of administrative overhead. For IFRS reporting purposes, the value of the asset will include interest capitalized during construction; whereas for Regulatory purposes the value of the asset will include an allowance for funds used during construction. The total cost of the asset is significant, relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed $300. There are numerous items (e.g. office furniture, loose tools, etc.) that are too small to capture in individual projects therefore blanket projects are utilized to capture these costs.

Capital versus O&M Expenditures

1) Capital

An expenditure is capital in nature if it involves: constructing or purchasing a new asset or upgrading it, rehabilitating or replacing an existing asset.

a. Constructing or purchasing a new asset

i. Outright purchase of fixed assets, such as land, a building, a vehicle, machinery, standby equipment, office furniture, etc.

ii. The entire cost of constructing new additions to physical assets such as transmission lines, distribution facilities, substations, etc.

iii. All startup and commissioning costs

b. Upgrade existing assets

i. An enlargement of existing structures or facilities

ii. To increase the capacity of an existing asset

iii. A substantial improvement in the facility affecting quality of output or reduces operating costs

c. Rehabilitate existing assets

i. As a general guideline, to determine if a cost falls into this category, one must consider if the expenditures were planned to be incurred at the time if purchasing the asset.

1. If the expenditures were planned at the time of purchase to occur in the future, they will be expensed to O&M when they are incurred.
2. When extraordinary, material unplanned items are incurred in the future, they will be considered capital.

ii. To insure achievement of life of an asset
iii. To extend the life of an asset beyond its normal service life

d. Replace existing assets
i. The substitution of new for existing facilities that are worn out, irreparably damaged, or have become inadequate in service.
ii. The substitution having substantially no greater capacity than the facility for which it is substituted.

2) Operation and Maintenance

a. Operational Expense
i. The cost of labour, expense and consumable materials used to start up or turn on a system and monitor its operations.
b. Maintenance Expense
i. The cost of labour, materials and expense to keep all parts of the system in a safe operating condition.

Specific Accounting Treatment

Following is the accounting treatment of some of the more common capitalization questions which are encountered.

1) Transformers – Capital/O&M
All transformers 50 KVA and under will be purchased under inventory and charged to fixed assets when installed and if replaced, returned to inventory and credited to fixed assets. Transformers greater than 50 KVA are charged directly to fixed assets. For policy on burnouts, planned and unplanned increases and shop repairs see D.1.a.10 in this manual.

2) Refurbishing & Installing Vehicle Service Bodies – Capital
This expenditure is eligible because it extends the service life of an asset.

3) First Time Painting of Street Lights – Capital
Considered a cost of installing a street light.

4) Switch Number Plates & Installation – Capital
Required for the safe operation of transmission facilities.

5) 5 kV Underground Replacement – Capital
Considered as a distribution rebuild.

6) Brushing – Capital
Capitalize if brushing at time of construction, first time spraying to kill remaining root system, line widening (i.e. the removal of entire trees) along right of ways for trees not previously cleared at time of construction or hazard tree removal for trees either on an existing right of way which has not been previously cleared or those trees outside the existing right of way.

7) **Brushing – O&M**
Mowing the regrowth of trees which were previously cleared and also the second and subsequent sprayings are O&M.

8) **Moving Expense – Capital/O&M**
The individual's moving expenses should be allocated to capital or O&M, or a combination of both, based on the type of work the individual is doing.

9) **Underground Splice Replacements – O&M**
There is no increase in capacity or life extension of the primary asset.

10) **Loose Tools and Office Furniture – Capital/O&M**
The key determinant is the $300 minimum cost which will decide if an item should be capitalized or expensed.

11) **Ground Rod Testing and Replacement – Capital / O&M**
Testing would be charged to O&M unless it leads to immediate major site specific replacement which would qualify the costs as a major capital item. Replacement costs would be capitalized if the work order is for a major replacement done at a specific site.

12) **Pole Inspection or Testing – O&M**
The work involved in inspecting or testing a pole to see if treatment is required.

13) **Pole Treating – Capital/O&M**
Any major pole treating program involving 50 poles or more would be considered capital. Programs of less than 50 poles will be charged to O&M.

14) **Temporary Generation – Capital/O&M**
The cost of renting a temporary generating station to supply load in an isolated fashion to allow a line to be rebuilt would be expensed for IFRS reporting purposes. For Regulatory purposes this cost would be capitalized.

15) **Gang Switch Maintenance – O&M**
Since the refurbishing of gang switches involves only the replacement of insulators in the gang switch assembly, this item should be charged to O&M. The intent is to keep the switch in operating condition.

16) **Substation Regravelling – O&M**
The costs should be charged to O&M as the substation life is not extended, nor is the asset value increased.

17) **URD Elbow & Insert Replacement – O&M**
Costs should go to O&M as essentially the underground system is being maintained in operating condition.

18) **Pedestal Replacement – Capital**
The associated costs should be capitalized and the pedestal being replaced, retired.

19) **Accreditation Manuals – Capital/O&M**
The costs to initially set up the manuals should be capitalized. However a revision to the manual should be expensed.

20) **Panel Upgrades – Capital**
Due to capacity increases, these costs would be eligible for capital.

21) Pole Replacement – Capital/O&M

All poles replaced on a pre-planned basis due to decay should be charged to capital and the old pole and labour to install them should be retired. Poles replaced on an emergency basis due to mechanical damage by vehicles or during storms should be expensed whether or not there is some evidence of wood decay.

22) Pole Stubbing – Capital/O&M

Stubbing of transmission lines on a pre-planned basis should be charged to capital as the intent to increase the service life of the poles. Unplanned pole stubbing would be expensed.

23) Conductor Replacement – Capital/O&M

Replacement of a conductor on a transmission or sub transmission line would be charged to capital if the length of the line is one mile or greater (three miles for a 3 phase line) regardless of the size of the conductor being replaced. Replacement of conductors on distribution lines will be charged to capital if the new conductor is of a larger size or insulation rating compared to the one being replaced. This applies to underground, aerial spaced and overhead conductors.

24) System Spares – Capital/Inventory

The cost of spares that are designated to support specific fixed assets are initially capitalized and depreciated. If the spare part turns over on a regular basis, consideration would be given to setting it up in inventory.

25) Leasehold Improvements – Capital

Leasehold improvements are capitalized where a lease agreement is in place. It is amortized using the straight-line method over the life of the lease plus one renewal period.

26) Postponed Projects – WIP

Costs incurred to date would remain in work-in-progress and reviewed periodically for appropriateness.

27) Properties Removed From Service (i.e. not disposed of)

Original cost would remain with assets in service and depreciated until disposed of.

28) Leases – Capital

Will be capitalized depending on the terms and conditions of the lease, particularly the issue of transfer of ownership at the conclusion of the lease. The lease obligation is included with long-term debt and the original cost is included in fixed assets.

The Yukon Electrical Company Limited
Continuity of Contributions in Aid of Construction 2010 - 2015

	($000s)								
	Opening Balance	Additions	Retirements	Ending Balance	Opening Accum. Amortization	Amortization	Retirements	Ending Accum. Amortization	Net Book Value
2010	41,379		(212)	44,938	15,791	1,221	(212)	16,800	28,138
Lower Post Health Centre 3 Phase Line		815							
Arkell Subdivision		799							
Takhini North Infill		310							
Whitehorse Copper		285							
Takhini North Subdivision Street Lights		282							
Ingram Subdivision Street Lights		140							
New Country Residential Subdivision in Haines Junction		105							
Ta'an Kwach'an Council Subdivision – Klondike Highway North		91							
Yukon Gardens Subdivision		69							
Yukon College		57							
Yukon Government Aircraft Plugins		56							
Stan McGowan 12-Plex		54							
Lot 1095 Gentain Lane		45							
Main Street Condominium		44							
Yukon Government - Yukon River Crossing Study and Design		43							
Takhini Lot 1371		42							
Yukon Government Core Library		42							
10 Units on Range Road		41							
Lot 1018 Main Street		40							
Yukon Government Carcross Water Front Place		38							
Grove Street New Lots		35							
Yukon Government Army Beach Sewage Lagoon		31							
Crestview Booster Station		30							
Champagne Aishihik First Nation Cultural Centre		25							
Northwestel Communication Tower Hotsprings Road		25							
Yukon Housing Seniors Housing – Jeckell Street		23							
Carcross Tagish First Nation Line Rerouting		21							
Other		183							
2011	44,938		(167)	50,503	16,800	1,289	(167)	17,922	32,581
Whistle Bend Subdivision Stage 1 & 2		1,152							
Grizzly Valley New Extension Out of Subdivision		415							
Takhini North Infill		384							
25 Wann Road – 65 Units		347							
Water Front Place Line Relocation		326							
Northwestel Fox Point		275							
Northwestel Minto		264							
Arkell Subdivision		263							
Whistle Bend Stage 1 & 2 Street Lights		245							
Falcon Ridge Development Stage 4		214							
Grizzly Valley New Extension In Subdivision		200							
Wharf Lighting 1st Ave. Whitehorse		133							
Diamond Ranch Extension		131							
Ingram 6-Plex Subdivision		130							
Yukon Government Haines Junction Willow Acres Residential Infill		115							
Whistle Bend Way Light Additions		107							
Lower Post Health Centre 3 Phase Line		104							
Trail Lighting along Whitehorse Waterfront to Shipyards Park		81							
Carcross Retail Shops		63							
Marsh Lake Landfill		61							
Champagne Aishihik First Nation Cultural Centre		55							
8-Plex Lot 1127 Hillcrest		35							
14th Ave Whitehorse		34							
River's Edge Development		34							
Eagle Eye Subdivision		33							
6-Plex 1204 Centennial		32							
Watson Lake Hospital		31							
Carcross Landfill		28							
Yukon Government Water Treatment Plant		27							
Boxwood Light Upgrade		24							
Other		389							
2012	50,503		(46)	54,075	17,922	1,371	(46)	19,247	34,828
Whistle Bend Subdivision Stage 1 & 2		649							
Grizzly Valley New Extension In Subdivision		300							
Whistle Bend Substation		200							
Grey Wolf 1583 Wann Road		193							
Yukon Government Haines Junction Willow Acres Residential Infill		160							
Whistle Bend Way Light Additions		140							
Lot 405 Takhini		132							
Mah's Point Condominiums		128							
Lot 1146 Crestview Development		127							
Yukon Government Tagish Land Fill		111							
Yukon Government Ross River Pole Move		111							
Whistle Bend Stage 1 & 2 Street Lights		108							
F.H. Collins Secondary School Transformer		86							
Mt. Sima T-Bar		76							
Hidden Haven		74							
Daylu Dena 10 Lots Lower Post		71							
Yukon Government Civl Excavations in Watson Lake		62							
Northwestel Minto		60							
Yukon Government Yukon River Powerline		59							
Lot 1368 Mayo Road		49							
Northwestel Fox Point		47							
Falcon Ridge Development Stage 4		45							
Ingram Subdivision 15 Units		44							
Lot 1395 North Klondike Highway		43							
Yukon Government Grizzly Valley Street Lights		43							
Lot 105 Otter Road		41							
Lot 122 Squatters Row		40							
Black Street – 6th Avenue Escarpment		36							
Yukon Government Mt. Lorne Land Fill		35							
Betty's Haven Shelter Lot 6		33							
City of Whitehorse Marwell Reroute		28							
Water Front Place Line Relocation		26							
Other		261							
2013	54,075		(142)	57,851	19,247	1,444	(142)	20,549	37,302
Residential Additions		2,438							
Street Lights		15							
Commerical		1,465							
2014	57,851		(142)	62,404	20,549	1,557	(142)	21,964	40,440
Residential Additions		3,024							
Street Lights		375							
Commerical		1,296							
2015	62,404		(142)	66,688	21,964	1,749	(142)	23,571	43,117
Residential Additions		2,912							
Street Lights		266							
Commerical		1,248							

YEC-YECL-16

Reference: Section 9 – Capital Additions – Fish Lake

Request:

(a) Please provide a table that shows capital expenditures for each unit of Fish Lake hydro-electric generating plant for actual and forecast years included in GRA application.

(b) Please explain expenditures with the amount more than $0.5 million.

(c) Please provide a continuity schedule for Fish Lake hydro-electric generating plant for 2010-2015 years by showing the following:

(i) Total plant year-end cost

(ii) Total plant capital additions for the year

(iii) Total plant amortization expense for the year

(iv) Total plant year-end accumulated amortization

(v) Total plant year-end net-book-value

(vi) Total plant net cost mid-year balance (based on iv above)

(vii) Total hydro generation for the year

(d) For c) above please combine all Fish Lake hydro-electric generating related costs.

Response:

(a) Please refer to YEC-YECL-16(a) Attachment 1.

(b) Please refer to YEC-YECL-16(c) Attachment 1.

(c) Please refer to YEC-YECL-16(c) Attachment 1.

(d) Please refer to YEC-YECL-16(c) Attachment 1.

The Yukon Electrical Company Limited
Fish Lake Hydro System Capital Expenditures By Year

Project Description	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
Fish Lake Unit #1 Turbine and Building Replacement	Bus Case # 2, Pg 9-26, 9-34, 9-44				717,000	1,024,000	2,167,000			**3,908,000**
Fish Lake Water Licence Renewal	Bus Case # 28, Pg 9-33, 9-42, 9-51				491,000	688,000	650,000			**1,829,000**
Fish Lake Dyke Upgrade	Bus Case # 7, Pg 9-44, 9-54						300,000	1,420,000		**1,720,000**
Fish Lake Ditch # 3 Diversion Structure Replacement	Bus Case # 9, Pg 9-54							1,640,000		**1,640,000**
Fish Lake Unit # 2 Penstock Replacement	Bus Case # 1, Pg 9-18, 9-26			486,000	70,000					**556,000**
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	Pg 9-12, 9-18, 9-26		153,000	294,000	18,000					**465,000**
Fish Lake Unit #1 Generator EOL Rebuild	Pg 9-5	463,000								**463,000**
Fish Lake Unit #1 Spillway	Pg 9-18, 9-26, 9-45, 9-55			212,000	26,000		20,000	100,000		**358,000**
Fish Lake Unit # 1 Tailrace Reconstruction	Pg 9-26				173,000					**173,000**
Fish Lake Unit # 2 Step-Up Transformer	Pg 9-34					172,000				**172,000**
Fish Lake Unit # 2 Turbine Inlet Valve (TIV) Replacement	Pg 9-34					171,000				**171,000**
Fish Lake Unit # 1 Replacement Wheel	Pg 9-12, 9-19		80,000	45,000						**125,000**
Fish Lake Ditch # 3 Drop Box Concrete Upgrade	Pg 9-19, 9-26			32,000	57,000					**89,000**
Fish Lake Incremental Purchase Power	Pg 9-12		69,000							**69,000**
Louise Lake Control Structure Gate Replacement	Pg 9-26				68,000					**68,000**
Fish Lake Head Pond # 2 Spillway Upgrade	Pg 9-45, 9-55						30,000	30,000		**60,000**
Fish Lake Dyke Widening	Pg 9-26				52,000					**52,000**
Fish Lake Control Room Monitor Upgrade	Pg 9-12		52,000							**52,000**
Fish Lake Unit # 2 SCADA	Pg 9-45						50,000			**50,000**
Fish Lake Unit # 2 Penstock Improvements	Pg 9-45						40,000			**40,000**
Water Pressue Monitor (Hobo) for Louise Lake	Pg 9-35					37,000				**37,000**
Hobo for Franklin Lake Water Monitoring	Pg 9-26				36,000					**36,000**
Fish Lake Unit # 2 Siding Replacement	Pg 9-45						35,000			**35,000**
Hobo Water Monitor for Fish Lake at Range Road	Pg 9-26				22,000					**22,000**
Fish Lake Unit # 1 Fiber Communication from Head Pond to Unit	Pg 9-45						20,000			**20,000**
Fish Lake Unit # 2 Building Improvements	Pg 9-45						20,000			**20,000**
Fish Lake Unit # 2 Vibration Monitoring	Pg 9-45						20,000			**20,000**
Grand Total		**463,000**	**354,000**	**1,069,000**	**1,730,000**	**2,092,000**	**3,352,000**	**3,190,000**	**-**	**12,250,000**

Fish Lake Hydro-Electric Generating Plant Continuity 2010-2015

	(i)	(ii)	(iii)	(iv)	(v)	(vi)	(vii)
	Total Plant Year-End Cost	**Capital Additions**	**Amortization Expense**	**Closing Accum. Amort**	**Plant Net Book Value**	**Plant Net Cost Mid-Year**	**(MWh) Hydro Generation**
2010	2,185,419	1,069,000	38,811	1,063,147	1,122,272	1,079,177	3,388
2011	3,884,419	1,730,000	75,347	1,138,494	2,745,925	1,934,098	3,638
2012	4,264,419	2,092,000	164,743	1,303,237	2,961,182	2,853,553	3,388
2013	10,186,419	3,352,000	176,000	1,479,237	8,707,182	5,834,182	4,329
2014	13,726,419	3,190,000	283,000	1,762,237	11,964,182	10,335,682	8,730
2015	13,726,419	-	337,000	2,099,237	11,627,182	11,795,682	8,730

YEC-YECL-17

Reference: Section 9 – Capital Additions – Fish Lake Unit #1 Turbine and Building Replacement

Request:

(a) Please provide details of the failure of Fish Lake Unit #1, including details of insurance proceeds received or expected to be received related to this failure.

(b) Please confirm the proposed date Fish Lake Unit #1 in-service date after rebuilding.

(c) Fish Lake Unit #1 Turbine and Building Replacement Business Case notes the following (page 6 of 8) as the reason for replacing the existing unit with modern equipment:

(i) Modern hydro turbine will be more efficient.

(ii) Modern hydro turbine will have lower operating costs.

(iii) Economic analysis indicates incremental cost of new equipment will be paid back in a reasonable time frame.

Please provide details of impact of each above reasons to Yukon Ratepayers (does the current GRA includes any benefits from increased efficiency, lower operating cost, etc.)

(d) What is the new updated average generation output from Fish Lake Unit #1?

(e) What is the annual average hydro generation for each unit? Does YECL propose to update the average Fish Lake generation from 8.73 GW.h as approved in YUB Order 2009-02 to reflect increased efficiency? If yes, please provide updated average generation forecast for each unit; if not, please provide reasons.

(f) Please provide rationale for separating Fish Lake Dike Upgrade (Business Case #7) and Fish Lake Ditch #3 Diversion Structure (Business Case #9) from Fish Lake Unit #1 Turbine and Building Replacement projects.

(g) The economic case is based on replacing the unit and building only. As evidenced by capital expenditures related to this facility and renewing its water license, considerable additional capital and operating expenditures were and are required during the test years in order to continue to operate this facility as well as Unit #2. Please provide an updated business case considering the life cycle cost analysis of the total expenditures over the future expected life of the facility (capital and future operating expenditures)

(h) Please provide a copy of 2012 Dam Safety Report (Fish Lake Ditch #3 Diversion Structure - Business Case #9, page 2 of 3).

Response:

(a) The turbine-generator failure occurred in March 2010. The shaft tying the turbine and generator became decoupled and consequently, the runner and shaft were ejected through the turbine casing, causing collateral damage to the structure and other equipment in the powerhouse. The lost integrity of the turbine casing allowed a significant volume of water to fountain in the powerhouse for approximately 90 minutes until the intake valve was closed.

Insurance proceeds were received based on the estimated refurbishment cost to return the same unit to service using like-for-like parts where available (and new parts replacing parts that are obsolete.) Facility cleanup charges and installation of a pressure-reducing valve system were also covered by the insurance claim.

Based on the above, the net claim received is broken down as follows ($000s):

Property Damage Claim	956
Less: Deductible (recorded in the Reserve for Injuries and Damages)	(100)
Proceeds Received	856

(b) The forecast in-service date is December 2013.

(c) As detailed in Business Case 2, Yukon Electrical expects an approximately 13% increase in output, approximately $22,000 in lower operating costs, and expects the incremental cost of the unit to be paid back by the incremental output in a reasonable time frame.

(d) There is no average generation output because the unit is not in service yet. Expected annual generation is 5.6GWh.

(e) For the annual average hydro generation please refer to YUB-YECL-37 Attachment 1, tab YUB-YECL-37(d). Yukon Electrical is not proposing to update the average Fish Lake generation based on historical annual averages consistently less than the approved 8.73GWh.

(f) The business cases were separated as they relate to different projects at different locations and at different times that are anticipated to be completed independently.

(g) Yukon Electrical has completed a lifecycle analysis for the Fish Lake hydro generating system for the period from 2008 to 2052. Please refer to YEC-YECL-17 Attachment 1 for the analysis and details.

The analysis takes into account future operating and maintenance costs from 2015 at an escalation rate of 2%.

Future capital expenditures beyond 2015 are forecast starting with $250,000 (in 2013 dollars) every five years, beginning in 2019.

The resulting LCOE is 12.1¢/kWh.

Please note that if this analysis is carried back further in time there would be an associated decrease in the LCOE as significant capital expenditures were not required in previous decades.

(h) Please refer to CW-YECL-17(a) Attachment 2.

Yukon Electrical - Lifecycle Cost - Levelized Cost of Energy at Fish Lake

Project Detail (Fish Lake Solar - Fish Lake Facility - YEC-YECL-17(a))

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Capital Cost ($)	$ 462,000	$ 231,000	$ 457,800	$ 1,481,000	$ 280,000	$ 972,000	$ 2,484,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 317,000	$ -	$ -	$ -	$ 350,000	$ -	$ -	$ -	$ -	$ -	$ 356,400	$ -	$ -	$ -	$ -	$ 426,700	$ -	$ -	$ -	$ -	$ 474,100	$ -	$ -	$ -	$ 529,100	$ -	$ -	$ -
Depreciated Years	40	40	40	40	40	40	40										30				30						30					30					30				30			

#1 = Electricity generation in year (kWh) 6,731,000

O&M (2013)	O&M Growth
$ 445,500	2.000%

Capital Ex.
$ 750,000

2013	Rate	Ratio	A.T. Cost	A.T. Cost
Debt	5.800%	55.00%	3.190%	3.190%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			8.979%	7.300%

Tax Rate	30%
CCA	8%
Discount Rate	8.027%
Real Discount	5.899%

#	[5]	[4]	[3]	[2]	[1]	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Ratebase	463,000	578,739	723,809	2,375,603	2,718,199	8,627,716	11,973,918	11,707,636	11,395,432	11,083,229	10,771,025	10,745,993	10,439,438	10,108,532	9,787,627	9,466,721	9,462,875	9,136,685	8,805,211	8,473,736	8,142,262	8,160,848	7,823,539	7,480,396	7,137,253	6,794,109	6,837,461	6,487,877	6,131,850	5,775,824	5,419,798	5,490,493	5,127,355	4,757,104	4,386,854	4,016,603	4,117,488	3,738,386	3,353,431	2,967,476	2,581,521	2,715,737	2,321,113	1,917,819	1,514,525
Return	16,900	27,822	47,110	112,880	184,559	411,866	746,752	854,704	831,922	809,139	786,328	774,018	761,350	737,963	714,536	691,109	678,354	667,015	642,606	618,627	594,418	592,697	571,009	546,999	521,646	496,987	485,054	473,641	447,655	421,668	395,667	385,252	374,317	347,286	330,356	293,228	272,990	244,814	216,639	188,461	179,272	169,451	140,006	110,560
Depreciation	5,261	11,930	15,206	37,404	62,483	143,797	266,283	312,204	312,204	312,204	312,204	316,555	293,906	320,906	320,906	320,906	326,190	331,470	331,474	331,474	331,474	343,143	343,142	343,142	343,142	349,585	356,026	356,026	363,138	370,250	370,250	370,250	378,103	385,955	385,955	385,955	385,955	396,624	403,294	403,294	403,294	403,294	403,294	403,294
Income Tax	(1,535)	(3,118)	(3,379)	(6,413)	(13,054)	(30,647)	(54,233)	(51,883)	(36,686)	(23,514)	(11,000)	(12,162)	(5,311)	14,723	22,017	29,311	32,547	36,154	40,166	44,000	48,716	47,054	48,320	49,778	48,623	47,124	45,233	44,445	43,226	41,699	38,713	39,570	40,253	41,744	42,577	43,747	44,206	45,322	46,438	47,554	47,965	(2,457)	(5,984)	(9,854)
# = Investment Expenditures in Year	20,626	46,644	59,037	141,551	233,988	525,018	958,802	1,115,027	1,107,230	1,097,799	1,088,866	1,088,431	1,088,697	1,073,592	1,057,459	1,040,295	1,037,991	1,034,643	1,014,489	993,551	971,892	967,020	941,347	927,442	912,969	887,973	881,763	874,900	848,121	820,910	793,303	786,923	779,333	750,216	720,751	690,967	684,376	677,256	646,108	614,660	582,939	576,896	570,337	537,308	504,006
Mt = Operations and Maintenance in Year	141,000	154,000	130,000	171,000	259,000	368,000	468,500	454,410	463,498	472,768	482,224	491,868	501,705	511,739	521,974	532,414	543,062	553,923	565,002	576,302	587,828	599,584	611,576	623,808	636,284	649,009	661,990	675,229	688,734	702,509	716,559	730,890	745,508	760,418	775,626	791,139	806,962	823,101	839,563	856,354	873,481	890,951	908,770	926,945
It + Mt	161,626	200,644	189,037	312,551	492,988	893,018	1,367,302	1,569,527	1,561,640	1,561,298	1,559,634	1,570,655	1,580,475	1,575,297	1,569,198	1,562,269	1,570,405	1,577,705	1,568,412	1,558,553	1,548,194	1,554,848	1,560,931	1,549,018	1,536,777	1,524,257	1,530,773	1,536,890	1,523,350	1,509,644	1,495,811	1,503,161	1,510,223	1,496,724	1,481,169	1,466,593	1,475,514	1,484,218	1,469,208	1,454,223	1,439,263	1,459,377	1,461,288	1,446,078	1,430,951
(It + Mt) / (1+r)^t	249,106	283,612	245,059	371,595	537,551	819,004	1,150,047	1,203,782	1,104,799	1,013,009	928,060	857,155	791,028	723,090	660,592	603,166	556,055	512,339	467,109	425,701	387,823	357,209	328,885	299,324	272,346	247,739	228,177	210,102	190,991	173,585	157,740	145,377	133,954	121,672	110,502	100,346	92,589	85,416	77,545	70,392	63,895	59,051	54,564	49,521	44,941
Actual Output	6,551,160	8,093,640	3,387,720	3,638,040	3,387,960																																								
Et / (1+r)^t	9,145,125	10,569,174	4,138,380	4,157,345	3,621,701	3,558,746	7,639,513	7,146,467	6,685,241	6,253,783	5,850,170	5,472,606	5,119,410	4,789,009	4,479,931	4,190,801	3,920,331	3,667,317	3,430,632	3,209,223	3,002,103	2,808,350	2,627,102	2,457,552	2,298,944	2,150,573	2,011,777	1,881,939	1,760,481	1,646,861	1,540,574	1,441,147	1,348,137	1,261,130	1,179,738	1,103,599	1,032,374	965,745	903,417	845,112	790,569	739,546	691,817	647,168	605,400

Levelized Cost of Energy 2013 ($/kWh) 0.121

Income Tax Calculation

Taxable Return	13,402	30,002	37,358	89,275	146,361	326,607	592,167	677,772	659,698	641,624	623,550	613,788	603,775	585,197	566,620	548,042	538,642	528,936	509,746	490,557	471,367	462,310	452,916	433,051	413,186	393,321	384,643	375,592	354,982	334,371	313,760	305,501	296,830	275,396	253,961	232,527	224,730	216,478	194,135	171,791	149,448	142,161	134,373	111,025	87,678
Capital Cost Allowance (CCA)	18,520	40,398	48,287	117,364	189,873	438,763	772,942	850,707	762,650	720,038	682,435	620,927	582,740	536,121	493,231	453,779	439,153	408,423	375,749	345,588	318,004	306,594	276,096	272,382	250,583	230,545	227,561	224,616	206,831	190,285	175,062	178,126	180,945	165,460	153,151	140,898	149,473	155,449	143,005	131,565	121,049	132,163	142,397	131,005	120,525
Taxable Income	(5,118)	(10,397)	(12,929)	(28,198)	(43,512)	(102,156)	(180,773)	(172,935)	(102,952)	(78,414)	(58,885)	(7,139)	21,035	49,077	73,389	94,263	99,489	120,512	133,997	144,969	153,363	155,716	176,820	160,669	162,603	162,776	157,082	150,976	148,151	144,086	138,698	127,375	115,885	109,937	100,810	91,629	75,257	61,029	51,130	40,227	28,400	9,998	(8,024)	(19,083)	(32,847)
Income Tax Payable	**(1,535)**	**(3,118)**	**(3,379)**	**(6,413)**	**(13,054)**	**(30,647)**	**(54,233)**	**(51,880)**	**(30,886)**	**(23,524)**	**(11,666)**	**(2,142)**	**6,311**	**14,723**	**22,017**	**28,281**	**32,347**	**36,154**	**40,199**	**43,490**	**46,009**	**46,715**	**47,054**	**48,200**	**48,778**	**48,823**	**47,124**	**45,233**	**44,445**	**43,226**	**41,699**	**38,213**	**34,766**	**32,678**	**30,263**	**27,988**	**22,577**	**18,311**	**15,339**	**12,268**	**8,523**	**2,999**	**(2,407)**	**(5,964)**	**(9,854)**

Capital Investments

2008																																												
Ratebase	463,000	457,739	447,216	436,693	426,170	415,648	405,125	394,602	384,080	373,557	363,034	352,511	341,989	331,466	320,943	310,420	299,898	289,375	278,852	268,330	257,807	247,284	236,761	226,239	215,716	205,193	194,670	184,148	173,625	163,102	152,580	142,057	131,534	121,011	110,489	99,966	89,443	78,920	68,398	57,875	47,352	36,830	26,307	15,784	5,261
Return	16,900	33,417	32,649	31,880	31,112	30,344	29,576	28,808	28,039	27,271	26,503	25,735	24,967	24,198	23,430	22,662	21,894	21,126	20,357	19,589	18,821	18,053	17,285	16,516	15,748	14,980	14,212	13,444	12,675	11,907	11,139	10,371	9,603	8,834	8,066	7,298	6,530	5,762	4,993	4,225	3,457	2,689	1,921	1,152	384
Depreciation	5,261	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523	10,523
Income Tax	(1,535)	(1,583)	(261)	1,034	2,641	5,203	8,542	11,353	14,197	16,766	19,072	18,379	17,687	16,992	16,298	15,605	14,911	14,218	13,524	12,830	12,137	11,443	10,750	10,056	9,363	8,669	7,976	7,282	6,588	5,895	5,202	4,508	3,814	3,121	2,427	1,734	1,040	347	(347)	(1,040)	(1,734)	(2,427)	(3,121)	(3,814)	(4,508)
Final Undepreciated Capital Cost	444,480	458,922	376,208	346,111	318,422	292,949	269,513	247,952	228,116	209,866	193,077	177,631	163,420	150,347	138,319	127,253	117,073	107,707	99,091	91,163	83,870	77,161	70,988	65,309	60,084	55,277	50,855	46,787	43,044	39,600	36,432	33,518	30,836	28,369	26,100	24,012	22,091	20,324	18,698	17,202	15,826	14,560	13,395	12,323	11,337
Tax Payable	13,402	28,499	25,860	25,281	24,672	24,052	23,463	22,844	22,235	21,626	21,017	20,407	19,798	19,189	18,580	17,971	17,362	16,752	16,143	15,534	14,925	14,316	13,706	13,097	12,488	11,879	11,270	10,661	10,051	9,442	8,833	8,224	7,615	7,006	6,396	5,787	5,178	4,569	3,960	3,350	2,741	2,132	1,523	914	305
2009																																													
Ratebase	121,000	119,593	116,779	113,965	111,151	108,337	105,523	102,709	99,895	97,081	94,267	91,453	88,640	85,826	83,012	80,198	77,384	74,570	71,756	68,942	66,128	63,314	60,500	57,686	54,872	52,058	49,244	46,430	43,616	40,802	37,988	35,174	32,360	29,547	26,733	23,919	21,105	18,291	15,477	12,663	9,849	7,035	4,221	1,407
Return	4,417	8,731	8,525	8,320	8,114	7,909	7,704	7,498	7,293	7,087	6,882	6,676	6,471	6,266	6,060	5,855	5,649	5,444	5,238	5,033	4,827	4,621	4,416	4,210	4,004	3,800	3,595	3,390	3,184	2,979	2,773	2,568	2,362	2,157	1,951	1,746	1,541	1,335	1,130	924	719	514	308	103
Depreciation	1,407	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814	2,814
Final Undepreciated Capital Cost	121,000	116,160	106,887	98,318	90,452	83,216	76,559	69,756	59,816	54,846	49,459	46,422	42,708	39,291	36,148	33,256	30,596	28,148	25,896	23,825	21,919	20,165	18,552	17,068	15,702	14,444	13,290	12,227	11,249	10,349	9,521	8,760	8,059	7,414	6,821	6,273	5,773	5,311	4,886	4,496	4,136	3,805	3,501	3,221	
Final Undepreciated Capital Cost	4,840	9,293	8,549	7,865	7,236	6,657	6,125	5,635	5,184	4,769	4,388	4,037	3,714	3,417	3,143	2,892	2,661	2,448	2,252	2,072	1,906	1,753	1,613	1,484	1,365	1,256	1,156	1,063	978	900	828	762	701	645	593	546	502	462	425	391	360	331	304	280	
Final Undepreciated Capital Cost	116,160	106,867	98,318	90,452	83,216	76,559	69,756	59,816	54,846	49,459	46,422	42,708	39,291	36,148	33,256	30,596	28,148	25,896	23,825	21,919	20,165	18,552	17,068	15,702	14,444	13,290	12,227	11,249	10,349	9,521	8,760	8,059	7,414	6,821	6,273	5,773	5,311	4,886	4,496	4,136	3,805	3,501	3,221	
Tax Payable	3,502	6,923	6,761	6,598	6,435	6,272	6,109	5,946	5,783	5,620	5,457	5,294	5,131	4,969	4,806	4,643	4,480	4,317	4,154	3,991	3,828	3,665	3,502	3,340	3,177	3,014	2,851	2,688	2,525	2,362	2,199	2,036	1,873	1,710	1,548	1,385	1,222	1,059	896	733	570	407	244	81
2010																																													
Ratebase	157,000	155,131	151,393	147,655	143,917	140,179	136,440	132,702	128,964	125,226	121,488	117,750	114,012	110,274	106,536	102,798	99,060	95,321	91,583	87,845	84,107	80,369	76,631	72,892	69,155	65,417	61,679	57,940	54,202	50,464	46,726	42,988	39,250	35,512	31,774	28,036	24,298	20,560	16,821	13,083	9,345	5,607	1,869	
Return	5,731	11,325	11,052	10,779	10,506	10,234	9,961	9,688	9,415	9,142	8,869	8,596	8,323	8,050	7,778	7,505	7,232	6,959	6,686	6,413	6,140	5,867	5,594	5,321	5,049	4,776	4,503	4,230	3,957	3,684	3,411	3,138	2,865	2,593	2,320	2,047	1,774	1,501	1,228	955	682	409	136	
Depreciation	1,869	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738	3,738
Undepreciated Capital Cost	157,000	150,720	138,662	127,569	117,364	107,975	99,337	91,390	84,079	77,352	71,164	65,471	60,233	55,415	50,982	46,903	43,151	39,699	36,523	33,601	30,913	28,440	26,165	24,071	22,146	20,374	18,744	17,245	15,865	14,596	13,428	12,354	11,366	10,456	9,620	8,850	8,142	7,491	6,892	6,340	5,833	5,366	4,937	4,542	
Capital Cost Allowance (CCA)	6,280	12,658	11,093	10,206	9,369	8,539	7,847	7,311	6,726	6,188	5,693	5,238	4,819	4,433	4,079	3,752	3,450	3,176	2,922	2,688	2,473	2,275	2,093	1,926	1,772	1,630	1,500	1,380	1,269	1,168	1,074	988	909	837	770	708	651	599	551	507	467	429	395	
Taxable Return	150,720	138,662	127,569	117,364	107,975	99,337	91,390	84,079	77,352	71,164	65,471	60,233	55,415	50,982	46,903	43,151	39,699	36,523	33,601	30,913	28,440	26,165	24,071	22,146	20,374	18,744	17,245	15,865	14,596	13,428	12,354	11,366	10,456	9,620	8,850	8,142	7,491	6,892	6,340	5,833	5,366	4,937	4,542	
Tax Payable	4,544	9,345	8,764	8,548	8,332	8,115	7,899	7,682	7,466	7,250	7,033	6,817	6,600	6,384	6,168	5,951	5,735	5,518	5,302	5,085	4,869	4,653	4,436	4,220	4,003	3,787	3,571	3,354	3,138	2,921	2,705	2,489	2,272	2,056	1,839	1,623	1,407	1,190	974	757	541	325	108	
2011																																													
Ratebase	1,667,000	1,646,671	1,606,012	1,565,354	1,524,695	1,484,037	1,443,378	1,402,720	1,362,061	1,321,402	1,280,744	1,240,085	1,199,427	1,158,768	1,118,110	1,077,451	1,036,793	996,134	955,476	914,817	874,159	833,500	792,841	752,183	711,524	670,866	630,207	589,549	548,890	508,232	467,573	426,915	386,256	345,598	304,939	264,280	223,622	182,963	142,305	101,646	60,988	20,329			
Return	60,849	120,214	117,245	114,277	111,309	108,341	105,372	102,404	99,436	96,468	93,499	90,531	87,563	84,595	81,626	78,658	75,690	72,722	69,754	66,785	63,817	60,849	57,881	54,912	51,944	48,976	46,008	43,039	40,071	37,103	34,135	31,166	28,198	25,230	22,262	19,294	16,325	13,357	10,389	7,421	4,452	1,484		
Depreciation	20,329	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659	40,659		
Undepreciated Capital Cost	1,667,000	1,600,320	1,472,294	1,354,511	1,246,150	1,146,458	1,054,741	970,362	892,733	821,314	755,609	695,161	639,548	588,384	541,313	498,008	458,167	421,514	387,793	356,770	328,228	301,970	277,812	255,587	235,140	216,329	199,023	183,101	168,453	154,977	142,578	131,172	120,678	111,024	102,142	93,971	86,453	79,537	73,174	67,320	61,934	56,980		
Capital Cost Allowance (CCA)	66,680	128,026	117,784	108,361	99,692	91,717	84,376	77,626	71,418	65,705	60,449	55,613	51,164	47,071	43,305	39,841	36,654	33,721	31,023	28,542	26,259	24,158	22,225	20,447	18,811	17,306	15,922	14,648	13,476	12,399	11,406	10,494	9,654	8,882	8,171	7,516	6,916	6,363	5,854	5,386	4,955	4,558		
Taxable Return	1,600,320	1,472,294	1,354,511	1,246,150	1,146,458	1,054,741	970,362	892,733	821,314	755,609	695,161	639,548	588,384	541,313	498,008	458,167	421,514	387,793	356,770	328,228	301,970	277,812	255,587	235,140	216,329	199,023	183,101	168,453	154,977	142,578	131,172	120,678	111,024	102,142	93,971	86,453	79,537	73,174	67,320	61,934	56,980	52,421		
Tax Payable	48,253	95,328	92,974	90,621	88,267	85,913	83,559	81,205	78,852	76,498	74,144	71,790	69,437	67,083	64,729	62,375	60,021	57,668	55,314	52,960	50,606	48,253	45,899	43,545	41,191	38,837	36,484	34,130	31,776	29,422	27,068	24,715	22,361	20,007	17,653	15,300	12,946	10,592	8,238	5,884	3,531	1,177		
2012																																												
Ratebase	380,000	375,250	365,750	356,250	346,750	337,250	327,750	318,250	308,750	299,250	289,750	280,250	270,750	261,250	251,750	242,250	232,750	223,250	213,750	204,250	194,750	185,250	175,750	166,250	156,750	147,250	137,750	128,250	118,750	109,250	99,750	90,250	80,750	71,250	61,750	52,250	42,750	33,250	23,750	14,250	4,750			
Return	13,871	27,396	26,701	26,006	25,311	24,615	23,920	23,225	22,530	21,835	21,140	20,444	19,749	19,054	18,359	17,664	16,969	16,274	15,579	14,883	14,188	13,493	12,798	12,103	11,408	10,712	10,017	9,322	8,627	7,932	7,236	6,541	5,846	5,151	4,456	3,760	3,065	2,370	1,675	980	284			
Depreciation	4,750	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500			
Undepreciated Capital Cost	380,000	364,800	339,616	308,767	284,065	261,566	240,662	221,169	203,502	187,222	172,344	158,465	145,708	134,125	123,395	113,531	103,562	93,488	84,309	75,026	66,638	58,145	49,547	41,844	34,036	26,123	18,106	9,984	1,757															
Capital Cost Allowance (CCA)	15,200	29,184	26,849	24,701	22,725	20,907	19,235	17,696	16,280	14,978	13,780	12,677	11,663	10,730	9,872	9,082	8,354	7,687	7,072	6,506	5,986	5,507	5,066	4,661	4,288	3,945	3,629	3,339	3,072	2,826	2,600	2,392	2,201	2,025	1,863	1,714	1,577	1,450	1,334	1,228	1,129			
Taxable Return	364,800	339,616	308,767	284,065	261,340	240,662	221,169	203,502	187,222	172,344	158,465	145,708	134,125	123,395	113,531	103,562	93,488	84,309	75,026	66,638	58,145	49,547	41,844	34,036	26,123	18,106	9,984	1,757	(7,575)	(15,493)	(23,326)	(31,078)	(38,753)	(46,353)	(53,881)	(61,339)	(68,730)	(76,057)	(83,322)	(90,528)	(97,678)			
Tax Payable	10,999	21,724	21,174	20,624	20,074	19,524	18,974	18,424	17,874	17,324	16,774	16,224	15,674	15,124	14,574	14,024	13,474	12,924	12,374	11,824	11,274	10,724	10,174	9,624	9,074	8,525	7,975	7,425	6,875	6,325	5,775	5,225	4,675	4,125	3,575	3,025	2,475	1,925	1,375	825	275			
2013																																												
Ratebase	5,972,000	5,695,435	5,742,308	5,589,179	5,436,051	5,282,923	5,129,795	4,976,667	4,823,538	4,670,410	4,517,282	4,364,154	4,211,026	4,057,897	3,904,769	3,751,641	3,598,513	3,445,385	3,292,256	3,139,128	2,986,000	2,832,872	2,679,744	2,526,615	2,373,487	2,220,359	2,067,231	1,914,103	1,760,974	1,607,846	1,454,718	1,301,590	1,148,462	995,333	842,205	689,077	535,949	382,821	229,692	76,564				
Return	217,990	430,390	419,211	408,032	396,853	385,675	374,496	363,317	352,138	340,959	329,780	318,601	307,422	296,243	285,064	273,885	262,706	251,527	240,348	229,169	217,990	206,811	195,632	184,453	173,274	162,095	150,916	139,737	128,558	117,379	106,200	95,021	83,842	72,663	61,484	50,305	39,126	27,947	16,768	5,589				
Depreciation	76,564	153,128	153,128	153,128	153,128	153,128	153,128	153,128	153,128	153,128	153,128	153,128	153,128

YEC-YECL-18

Reference: Section 9 – Capital Additions – Fish Lake Unit #2 Penstock Replacement

Request:

(a) Explain why (with numerical support) the life cycle cost of this life extension work is economically preferable to abandonment of the facility (i.e. replace with purchase of wholesale power).

Response:

(a) Please refer to YUB-YECL-37(a).

YEC-YECL-19

Reference: Section 9 – Capital Additions – 500kW Mobile Generator

Request:

(a) Please provide list of YECL diesel units with unit size and expected retirement dates as of December 31, 2012 and as of December 31, 2015 by community.

(b) Please identify location of mobile units and communities they serve.

Response:

(a) Please see the following table for a list of diesel units with unit size and expected retirement dates. Yukon Electrical does not foresee a change in expected retirement dates as listed below from December 31, 2012 to December 31, 2015.

CUL #	Location	Unit #	Rating (kW)	Expected Retirement Date
303	Beaver Creek	1	250	2014 *
378	Beaver Creek	2	360	2013
354	Beaver Creek	3	400	>10 Years
467	Destruction Bay	1	600	>10 Years
372	Destruction Bay	2	300	2015 *
230	Destruction Bay	3	220	2014
414	Old Crow	1	600	>10 Years
355	Old Crow	2	400	2016
384	Old Crow	3	170	2015
422	Watson Lake	1	800	2022
257	Watson Lake	2	800	2015
352	Watson Lake	3	1000	2021
258	Watson Lake	4	1500	2013
466	Watson Lake	5	750	>10 Years
423	Watson Lake	6	800	2019
460	Swift River	1	90	2020
413	Swift River	2	80	2013
375	Pelly Crossing	1	275	>10 Years
470	Pelly Crossing	2	600	>10 Years
405	Pelly Crossing	3	300	>10 Years
310	Carmacks	1	1600	>10 Years
265	Ross River	1	1000	>10 Years
416	Haines Junction	1	1750	>10 Years
376	Teslin	1	1500	>10 Years
186	Stewart Crossing	3	150	>10 Years

***** During the interrogatory response process, it has come to Yukon Electrical's attention that it mistakenly identified the replacement of Beaver Creek #1 and Destruction Bay #2 as years 2015 and 2014, respectively. The correct years should have been 2014 and 2015. As the forecast costs for the two replacements are each $600,000, there is no impact to Yukon Electrical's overall capital forecast for 2014 or 2015.

(b) Yukon Electrical currently has three mobile units available for operation. Two are low voltage units (120/240 volt) sized at 225kW and 250kW. These units are used to provide backup to the communities of Keno, Swift River and Deep Creek. They also assist Yukon Electrical to provide power to small sections of the distribution system in the case of system improvements or long duration outages.

The third unit, a 350kW generator, provides 2400 volt backup to the communities of Beaver Creek, Destruction Bay, Old Crow and Watson Lake.

These units are stationed in Whitehorse and are dispatched as required.

YEC-YECL-20

Reference: Section 9 – Capital Additions – Carcross 2MVA Standby Diesel Unit

Request:

(a) Please compare Carcross 2MVA Standby Diesel Unit cost to the cost of Carcross new 1.5 MW Power Plant as proposed in YECL's 2008/09 GRA. Please explain any differences.

(b) Project business case does not include capital cost and/or operating cost estimates for alternatives. This will not allow assess the economic benefit to ratepayers. Please provide business case for the projects with an economic analysis, including rate impacts.

(c) Please explain and provide rationale for YECL's "...threshold minimum load of 1.0 MWHs and 300 customers to enact the N-1 planning criteria."

Response:

(a) In Yukon Electrical's 2008/09 GRA, the estimated cost for the 1.5 MW standby diesel unit was $2.0M.

The estimated cost to implement the project in 2015 for a 2 MW unit is $3.0M, which is comprised of the following:

· 2,000kW Self-contained generator (sized for cold load pickup)	$2,500,000
· Engineering, Design	100,000
· Transformer, cables, vault, cable tray	100,000
· OSS (grid inter-tie/synchronization)	75,000
· Substation bus extension	50,000
· Civil – genset pad, fuel tank pad	50,000
· Fuel tank, piping, utilidor	50,000
· SCADA and PLC	35,000

· Ground grid	20,000
· Fence	20,000
	$3,000,000

The increased cost is due to the installation of a larger capacity generating unit and associated equipment as well as implementing the project seven years later.

(b) There are no significant incremental capital or operating costs associated with the status quo alternative. Yukon Electrical would continue its brushing program to reduce incident outages caused by trees on the line. However, the inherent risk from being on a long radial feed would remain.

The option to close the loop back to the Whitehorse line by including a new substation and line would address issues related to the vulnerability of the radial feed portion to Carcross and Tagish, but does not address the radial supply line out of Whitehorse. The approximate cost of this option is $3.5M comprised of $1.5M for a new substation and $2.0M for new line.

There is no direct economic benefit related to the addition of this unit, as the generating unit is for standby duty. The 2015 rate impact of the recommended alternative is $229,000.

(c) The rationale for a threshold minimum load of 1.0 MWHs to enact a N-1 planning criteria is based on the January 2006 Yukon Energy Corporation 20 Year Resource Plan section 3.4 Summary: Revised Capacity Planning Criteria on pages 88-89:

> 2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.
>
> 3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already

have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

The selection of 300 customers is recommended as a minimum community size for locations with sufficient load to benefit a reasonable number of customers.

YEC-YECL-21

Reference: Section 9 – Capital Additions – Whistle Bend

Request:

(a) Please provide a summary table that combines costs by year for the business cases 16, 17, 19, 20 and 26.

(b) Please include forecast customer contributions to the summary table in a) above.

(c) Please provide number of customers forecast to be included in test years, including forecast additional electricity required to supply energy to the subdivision.

(d) Please provide source of electricity to the Whistle Bend subdivision.

Response:

(a) Please refer to YEC-YECL-21(a) Attachment 1 for a table of the capital expenditures for Whistle Bend.

(b) Please refer to YEC-YECL-21(a) Attachment 1 for a table of actual and forecast customer contributions for Whistle Bend.

- The customer paid 100% of subdivision costs.
- Yukon Electrical invested as per the T&Cs for the street lights.
- Yukon Electrical built the substation to off load existing overloaded lines and overloaded substation in the area. The 34.5kV lines were added to loop an existing substation that feeds about 5MW of power to customers that Yukon Electrical was not able to take out of service for any operation or maintenance. These system improvements were fully invested by Yukon Electrical, with the exception of the cost of two breakers to feed the Whistle Bend subdivision which were 100% contributed by the customer.

(c) Please refer to YEC-YECL-3(a) Attachment 1 for the number of customers forecast for Whistle Bend. Yukon Electrical has designed and built the Whistle Bend substation to accommodate the load expected of a subdivision that will be

expected to have a population of 8,000 residents with a mix of single family, multiple family and commercial lots. Estimates for the electricity demand of the fully realized subdivision is 15 – 20 MW.

(d) The source of electricity for Whistle Bend subdivision is the Whitehorse grid. Yukon Electrical does not control the supply of power to the Whitehorse grid, except Fish Lake Hydro, though the main source is usually a combination of the Aishihik and Whitehorse Hydro stations. To supply the Whistle Bend subdivision with adequate electrical service, Yukon Electrical had to build a new Whistle Bend substation and connect it in to the Whitehorse distribution system as the existing substations in the area were unable to supply the significant additional load of the Whistle Bend subdivision.

The Yukon Electrical Company Limited
Summary of Whistle Bend Capital Projects

	Business Case #	2010	2011	2012	2013	2014	Sum of Total
Capital Expenditures:							
Whistle Bend Subdivision Stage 1 & 2	16		1,242,000	683,000			**1,925,000**
Whistle Bend Subdivision Stage 3	17					1,200,000	**1,200,000**
Whistle Bend 34.5kV Substation Distribution Lines	19	492,000	156,000				**648,000**
Whistle Bend Substation	20		1,690,000	423,000			**2,113,000**
Whistle Bend Stage 1 & 2 & 3 Street Lights	26				75,000	450,000	**525,000**
		492,000	**3,088,000**	**1,106,000**	**75,000**	**1,650,000**	**6,411,000**
Customer Contributions:							
Whistle Bend Subdivision Stage 1 & 2	16		(1,152,000)	(649,000)	(124,000)		**(1,925,000)**
Whistle Bend Subdivision Stage 3	17					(1,200,000)	**(1,200,000)**
Whistle Bend 34.5kV Substation Distribution Lines	19						**-**
Whistle Bend Substation	20			(200,000)			**(200,000)**
Whistle Bend Stage 1 & 2 & 3 Street Lights	26		(245,000)	(108,000)			**(353,000)**
		-	**(1,397,000)**	**(957,000)**	**(124,000)**	**(1,200,000)**	**(3,678,000)**
Net Capital Expenditures							
Whistle Bend Subdivision Stage 1 & 2	16	-	90,000	34,000	(124,000)	-	**-**
Whistle Bend Subdivision Stage 3	17	-	-	-	-	-	**-**
Whistle Bend 34.5kV Substation Distribution Lines	19	492,000	156,000	-	-	-	**648,000**
Whistle Bend Substation	20	-	1,690,000	223,000	-	-	**1,913,000**
Whistle Bend Stage 1 & 2 & 3 Street Lights	26	-	(245,000)	(108,000)	75,000	450,000	**172,000**
		492,000	**1,691,000**	**149,000**	**(49,000)**	**450,000**	**2,733,000**

YUB-YECL-1

Reference: Deferral Accounts, YECL Application, Page 1-5

The deferral accounts for which Yukon Electrical is seeking approval meet the standard criteria for the establishment of a deferral account:

Request:

(a) Please cite the regulatory body, regulation or rules which provide or state the criteria for a deferral account.

(b) For the seven deferral accounts listed on page 1-6, please state which criteria applies, and if the second criteria applies, please provide the analysis that determined that "an error in forecasting could produce a loss or a gain of a substantial magnitude".

(c) How did YECL manage these costs prior to the proposal of deferral accounts?

Response:

(a) Paragraph 12 of Board Order 2009-2 regarding Yukon Electrical's 2008/2009 GRA states the following, which is consistent with the criteria used by Yukon Electrical to determine which items warrant deferral treatment for 2013-2015:

> With respect to the proposed Pelly Crossing deferral account, the Board notes that the typical criteria used in determining whether to approve the use of a deferral account are the level of uncertainty regarding the accuracy of the forecast and the utility's ability to control the factors influencing the forecast.

Additionally, the two criteria for a deferral account outlined on pages 1-5 and 1-6 of the Application have been specifically tested, reviewed and approved in recent ATCO Electric applications to the AUC.

(b) For the seven deferral accounts for which Yukon Electrical is seeking approval, all are considered to be outside the control of the company and are not reasonably forecastable.

(c) Whitehorse Copper Tailings – This is a new industrial customer that is uncertain as to the exact timing of its start-up as well as its ultimate load. This area was not an issue for Yukon Electrical in its most recent GRAs as it was not forecasting industrial customers.

Purchased Power Flow Through – Yukon Electrical is requesting a continuation of the existing deferral account with no proposed changes.

Diesel Contingency Fund – Yukon Electrical is requesting a continuation of the existing deferral account with no proposed changes.

Fuel Price Flow Through – While Yukon Electrical is requesting a continuation of the existing deferral account, the request includes approval to change the methodology for calculating the deferral to include liquefied natural gas (LNG) as well as diesel fuel in Watson Lake. The purpose of this deferral continues to be to protect both customers and Yukon Electrical's shareowner from changes in fuel price as compared to forecast.

Depreciation Parameters – The intention of Yukon Electrical's requested deferral is, to the extent possible, permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, the purpose of deferral is not to address risk. This deferral addresses the advent of IFRS since Yukon Electrical's 2008-2009 GRA.

Rate of Return on Common Equity – In Board Order 2009-02, Yukon Electrical was directed for 2008 and 2009 to tie its ROE to the BCUC benchmark return on equity (ROE) for each respective year. As a result, the ROE for 2008 was set at 9.08% (BCUC benchmark ROE + 0.46% risk premium) and the ROE for 2009 was a placeholder, to be set at 46 basis points above the BCUC 2009 benchmark ROE (which ended up being 8.47%). As the 2009 BCUC benchmark ROE was known by the time Yukon Electrical completed its compliance filing, no deferral or true-up was required as it was incorporated in base rates.

Using the same methodology as it was directed to use in 2008 and 2009, Yukon Electrical has requested approval to set its ROE at the BCUC benchmark ROE + 0.46% for 2013-2015. As the BCUC has set the benchmark ROE at 8.75% with no AAM for 2013, Yukon Electrical has not requested a deferral for 2013. For 2014 and 2015, as there is an AAM that may impact the BCUC benchmark ROE for those years and because such a change may not be known at the time of Yukon Electrical's compliance filing related to this proceeding,

Yukon Electrical is requesting a deferral to flow the impact from the AAM, if any, through to customers for the years 2014 and 2015.

Defined Benefit Pension Plan – When Yukon Electrical filed its last GRA in 2008, Federal pension regulations in place required updated actuarial valuations to be completed for defined benefit ("DB") pension plans at least once every three years. An actuarial valuation for the DB plan that Yukon Electrical participates in was completed as at December 31, 2006 to determine the required funding for the years 2007-2009. As a result, the level of the required contributions to the plan was known for the three year period 2007-2009 and, more specifically, for the test period of 2008-2009. Since 2009, Yukon Electrical has contributed to its DB plan based on the results of the actuarial valuations that were prepared during this period. As part of this 2013 – 2014 Application, Yukon Electrical is requesting a deferral account that maintains risk at a status quo level as compared to the 2008-2009 test period.

YUB-YECL-2

Reference: Deferral Accounts, YECL Application, Page 1-6

Request:

Please explain how depreciation parameters, rate of return on common equity and the defined benefit pension plan are not under the control of the company.

Response:

Depreciation Parameters

Events which could potentially lead to a change in life depreciation parameters include: functional obsolescence or inadequacy, technological change, changing requirements of customers and market forces, customer growth, and legal and regulatory requirements. Net salvage can be affected by changes in technology in the removal of property, inflation (which can significantly affect removal costs), and changes in market demand and market prices which can affect salvage values. None of these events are under the control of the company.

Rate of Return on Common Equity

The BCUC benchmark return on equity for 2014 and 2015 is subject to an automatic adjustment mechanism (AAM) that will become operative if a long term Canadian bond yield of 3.8% is met or exceeded. Yukon Electrical does not have any control over the calculation of the AAM or long term Canadian bond yields and, consequently, does not have any control over the benchmark return on equity for 2014 and 2015.

Defined Benefit Pension Plan

Federal pension regulations require the defined benefit pension plan in which Yukon Electrical participates to file an actuarial valuation which sets out funding requirements. The valuation report is prepared by Mercer (Canada) Limited in accordance with applicable pension legislation and actuarial standards of practice in Canada. The results of the valuation and, consequently, the funding requirements are impacted by actuarial assumptions such as investment returns, inflation rates and demographic and societal factors, which are not under the control of Yukon Electrical.

YUB-YECL-3

Reference: Flow-through costs, YECL Application, Page 1-6

Yukon Electrical also seeks the ability to flow-through (dollar for dollar) to the tariff any costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that Yukon Electrical operates under, or that bear on the nature and extent of Yukon Electrical's obligations as a regulated utility and which impact its 2013-2015 revenues or revenue requirement.

YECL's request appears open-ended.

Request:

(a) Does YECL view the flow-through of the above as something that can be invoked without Board approval?

(b) What has changed in YECL's environment that requires YECL to now make such a request?

Response:

(a) No. Similar to other approved deferral accounts, Yukon Electrical expects that any amount recorded by Yukon Electrical would be brought forward for Board approval as part of a future application.

(b) This deferral has been requested by Yukon Electrical in order to maintain consistency with a similar deferral that was approved as part of the 2011-2013 GRAs of each of Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited in Decisions 13-2011 and 17-2011, respectively. In those decisions, the approved wording of the deferral account was as follows:

> …a deferral account which would be used to record amounts associated with any Board decisions that result in changes to the rules or parameters that Northland operates under, including such areas as the billing system, collection practices or the frequency of meter reading, or statutory or legislative provisions or changes that

bear on the nature and extent of Northland's regulated utility obligations or operations and which impact Northland's 2011-2013 Revenues and/or Revenue Requirements. For clarity, no such recorded amounts would be approved by the Board as part of this Negotiated Settlement. Rather, the balance(s) would be brought forward by Northland for consideration in Northland's next General Rate Application.

YUB-YECL-4

Reference: IFRS, YECL Application Section 1, Attachment 2

Request:

Of the 24 boxes listed in Attachment 2, 21 list the change to IFRS as having either no change or the proposed treatment has no impact. Please comment on how this may affect accounting and administrative costs for YECL.

Response:

Of the 24 boxes listed in Attachment 2, 21 are described as having no impact on this Application. That is, for the purpose of this regulatory filing, Yukon Electrical has continued to treat the items the same as would have been the case under Canadian GAAP and, accordingly, there is no impact to Yukon Electrical's revenue requirement as a result of the transition to IFRS. For the 3 remaining items that were not specifically identified as not being impacted by the change to IFRS (Regulatory Assets and Liabilities: Deferral Accounts, Deferred Charges and Depreciation), there was also no impact to Yukon Electrical's revenue requirement for 2013-2015 as a result of the transition to IFRS.

Further to the above, however, many of the items listed are now required to be treated differently for financial statement purposes under IFRS than they were treated under Canadian GAAP. Some of the more notable differences include:

- Regulatory Assets and Liabilities: Deferral Accounts – deferral accounts must continue to be recorded for regulatory purposes, but IFRS does not permit the recording of deferral accounts on the balance sheet;

- Capitalization/Non-Capitalization of Costs: Borrowing Costs/Equity Allowance for Funds Used During Construction (AFUDC) – calculation of borrowing costs to be capitalized for IFRS (interested during construction) is different than the standard regulatory method of calculating AFUDC;

- Treatment of Insurance Proceeds – insurance proceeds related to the loss of property, plant and equipment are recognized in income under IFRS while they are considered proceeds of disposition for rate-making purposes;

- Depreciation – Canadian GAAP permitted regulatory companies to record depreciation based on the depreciation parameters set by the latest depreciation study, while IFRS requires an annual review of depreciation parameters and the immediate implementation of new parameters if they are found to have changed materially;

- Accounting for Income Taxes – Yukon Electrical records taxes based on the amount actually payable or receivable in the current year for regulatory reporting, but is required to recognize both current and deferred income taxes under IFRS;

- Pension Costs/ Other Employment Benefits – IFRS requires these items to be recorded on the accrual basis while, for regulatory purposes, Yukon Electrical recognizes pension and OPEB costs on the cash basis; and

- Reserve for Injuries and Damages and Rate Case Reserve – costs are expensed in the year incurred under IFRS.

All of these items requiring different treatment for regulatory and financial statements purposes can result or have resulted in Yukon Electrical being required to maintain two sets of financial records. Maintaining two sets of records adds complexity and additional reconciliation requirements to reporting for both regulatory and financial statement purposes. As well, there are now two sets of “rules” that accountants at Yukon Electrical have to understand and consider when recording transactions.

YUB-YECL-5

Reference: Defined Pension Benefit, YECL Application, Page 5-3, YECL Application, Schedule 5-1 and Schedule 5-2

For the purposes of this Application, the 2013 test period assumes the same defined benefit contribution rates as 2012. Since the next defined benefit pension actuarial evaluation will be completed as of December 31, 2012 to determine 2013 required funding, any required change to the 2013 defined benefit pension funding requirements will impact the defined benefit pension expense related to YECL's eligible northern based staff. Beginning in 2013, YECL is requesting a deferral account to flow through the increases or decreases to required cash contributions to the company's defined benefit pension plan as a result of the required annual actuarial evaluations.

The Board seeks clarification in relation to defined benefit pension actuarial evaluation and the forecast pension costs during the test period.

Request:

(a) YECL submitted that the pension valuation will be completed by December 31, 2012. Please explain whether or not YECL is able to provide an update as to what the actual pension cost for 2013. If confirmed, please explain how this will affect YECL's O&M forecasts for 2013, 2014, and 2015.

(b) Please describe whether YECL will complete another defined benefit pension actuarial evaluation during the test period. If YECL is not expecting to complete another actuarial evaluation during the test period, please indicate when YECL expects to complete another one.

(c) Please explain whether YECL shares a pension plan with its ATCO affiliates. If not, please provide more details about the nature of this pension plan.

(d) If YECL shares a pension plan with its ATCO affiliates, describe whether YECL's regulated affiliates in other Canadian jurisdictions have a deferral account for their defined benefit pension plans. If yes, please describe this treatment (e.g. only current service portion, only special payments, or both).

(e) Schedule 5.1 does not provide an account for pension expense. Please provide a table showing the pension expense for 2008, 2009, 2010, 2011, and 2012, and where applicable, indicate the YECL forecasted pension expense YECL and the

actual pension expense for these years. Also break these costs into those attributable to current service payments and those attributable to special payments.

(f) Please describe which accounts in schedule 5.1 are affected by pension expenses and breakout the pension expenses from these accounts (i.e. show the account amounts less expenses attributable to pension benefits).

(g) Please indicate what percentage of YECL employees are under a defined benefit pension plan versus a defined contribution pension plan? Can new employees to YECL be covered under a defined benefit pension plan?

Response:

(a) The pension valuation as at December 31, 2012 was completed in July 2013. Please refer to YUB-YECL-5(a) Attachment 1 for a copy of the valuation.

As a result of this valuation, Yukon Electrical's required DB pension funding for 2013 is as follows:

Current service	$605,000
Special payment	$351,000
Total	$956,000

The impact on forecast O&M for 2013 is a decrease of $203,000 ($1,268,000 – 956,000 = 312,000 x 65% = $203,000).

This valuation does not have an impact on the O&M forecasts for 2014 and 2015 as the required DB pension funding for each of those years is not known at this time. An actuarial valuation as at December 31, 2013 will be completed in the second or third quarter of 2014 to determine the 2014 funding requirements and a valuation as at December 31, 2014 will be completed in the second or third quarter of 2015 to determine the 2015 funding requirements.

(b) Yes, Yukon Electrical will complete a defined benefit pension actuarial evaluation for each year during the test period.

The Pension Benefits Standard Act ("the Act") is the legislation that governs Federally-registered defined benefit pension plans such as the plan Yukon Electrical participates in. Regulations made under the Act set out

minimum funding requirements and conditions for when an updated defined benefit pension actuarial valuation is required to be prepared.

Regulations amending certain regulations made under the Act, which came into force on July 1, 2010, now generally require the filing of an actuarial valuation report on an annual basis. As a result, Yukon Electrical will be required to complete a defined benefit pension actuarial valuation as at December 31, 2013 in the second or third quarter of 2014 to determine the 2014 funding requirements and to complete a valuation as at December 31, 2014 in the second or third quarter of 2015 to determine the 2015 funding requirements.

(c) Yukon Electrical does share a pension plan with its ATCO affiliates. Canadian Utilities Ltd. (CU) sponsors two pension plans: Plan 1 (DB and DC) and Plan 2 (DB only). Yukon Electrical employees who are members of the DC plan participate in Plan 1. Yukon Electrical employees who are members of the DB plan participate in Plan 2 along with employees of other CU subsidiary companies located in the Yukon Territory, Northwest Territories, Nunavut and Ontario, such as Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited.

(d) Beginning in 2013, both Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited have deferral accounts approved to flow through all increases or decreases to required non-capitalized related cash contributions to the defined benefit pension plan. This includes both the current service and special payment portions of the contributions.

Both ATCO Electric – Distribution and ATCO Gas are under Performance-Based Regulation ("PBR") beginning in 2013. The existing special payment deferral accounts of both companies covering special payments were discontinued upon the implementation of PBR. However, in the event of a material change in pension obligations (either positively or negatively), a Z factor application would be available to address the change. Similar to a deferral, a Z factor application is a mechanism that allows a utility to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan period.

For its 2011-2012 GTA, ATCO Electric – Transmission had a deferral account approved to flow through changes in cash contributions for the special payment portion of required defined benefit funding. However, in its 2013-2014 GTA, filed

in June 2012, ATCO Electric – Transmission has requested to change the deferral to include both the current service and special payment portions of the required funding.

For 2011-2012, ATCO Pipelines had a deferral account approved to flow through changes in cash contributions for the special payment portion of required defined benefit funding. However, in its 2013-2014 GRA, filed in December 2012, ATCO Pipelines has requested to change the deferral to include both the current service and special payment portions of the required funding.

(e) Please refer to YUB-YECL-5(e) Attachment 1 for total pension expense included in Schedule 5.1.

(f) Any account on Schedule 5.1 that includes salaries and wages expenses is affected by pension, as benefit expenses are allocated to each account based on salaries and wages. Please refer to YUB-YECL-5(f) Attachment 1 for a revised schedule 5.1 showing the account amounts less expenses attributable to pension benefits.

(g) At December 31, 2012, 36% of active Yukon Electrical employees were members of the defined benefit pension plan while 64% of active employees were members of the defined contribution pension plan.

In general, new employees to Yukon Electrical are not eligible to be covered under the DB pension plan as it has been closed to new entrants since January 1, 1997. However, new employees to Yukon Electrical who transfer from an ATCO affiliate who were already covered under a DB pension plan sponsored by Canadian Utilities Ltd. continue to be part of the DB pension plan.

MERCER

TALENT • HEALTH • RETIREMENT • INVESTMENTS

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2012
RETIREMENT PLAN FOR EMPLOYEES OF CANADIAN UTILITIES LIMITED AND PARTICIPATING COMPANIES – PLAN 2

JULY 2013

Office of the Superintendent of Financial Institutions Registration Number: 56344
Canada Revenue Agency Registration Number: 0955138

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound up in the future. In fact, even if the plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the *Pension Benefits Standards Act*, the *Income Tax Act* and related regulations that are effective as of the valuation date. Mercer is not engaged in the practice of law or tax advice. This report does not constitute and is not a substitute for legal advice.

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Summary of Results

	31.12.2012	31.12.2011
Going Concern Financial Status		
Market / Smoothed value of assets	$31,843,600	$29,540,500
Going concern funding target	$36,073,600	$37,908,900
Funding excess (shortfall)	($4,230,000)	($8,368,400)
Hypothetical Wind-up Financial Position		
Wind-up assets	$31,643,600	$29,550,200
Wind-up liability	$37,725,500	$33,571,200
Wind-up excess (shortfall)	($6,081,900)	($4,021,000)
Funding Requirements in the Year Following the Valuation[1]		
Total current service cost	$728,100	$886,800
Estimated members' required contributions	($46,000)	($52,000)
Estimated employer's current service cost	$682,100	$834,800
Expense allowance	$60,000	$60,000
Total	$742,100	$894,800
Employer's current service cost as a percentage of members' pensionable earnings	30.31%	32.79%
Minimum special payments	$469,100	$877,680
Estimated minimum employer contribution	$1,211,200	$1,772,500
Estimated maximum eligible employer contribution	$6,824,000	$9,263,200
Next required valuation date	31.12.2013	31.12.2012

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To The Management Pension Committee of Canadian Utilities Limited

At your request, we have conducted an actuarial valuation of the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies - Plan 2 (the "Plan"), sponsored by Canadian Utilities Ltd. (the "Company"), as at the valuation date, December 31, 2012. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the plan as at December 31, 2012 on going concern, hypothetical wind-up and solvency basis;
- The minimum required funding contributions from 2013, in accordance with the *Pensions Benefits Standards Act, 1985* (the "Act"); and
- The maximum permissible funding contributions from 2013, in accordance with the *Income Tax Act*.

The information contained in this report was prepared for the internal use of the Company and for filing with the Office of the Superintendent of Financial Institutions ("OSFI") and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the OSFI and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2013, or as at the date of an earlier amendment to the Plan.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, we have reflected a margin for adverse deviations in our going concern valuation by reducing the going concern discount rate by 2.1% per year after January 1, 2020.
- We have reflected the Company decisions for determining the solvency funding requirements. Specifically, the same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2011

Pension Plan

There have been no special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2012. The Plan has not been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	**Previous valuation**
Discount rate:	6.10% initially, then 4.00% starting in 2020	6.10% initially, then 3.30% starting in 2020
Indexing rate:	1.85%	2.00%
Pensionable earnings increases:	3.25% plus merit & promotion	3.75% until 2012, 3.25% thereafter, plus merit and promotion
Termination rates:	No termination	100% of Plan experience 1983 through 1985
Asset valuation method:	Market	Smoothed

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going concern methods and assumptions is provided in Appendix C. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

There have been no changes to the *Pension Benefits Standards Act* (the "Act") or the relevant regulations which impact the funding of the Plan.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

We have assumed that all the Plan's assets are available to cover the Plan's liabilities presented in this report.

3

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	12.31.2012	12.31.2011
Assets		
Market value of assets	$32,958,400	$30,993,600
In-transit amount	($1,114,800)	($1,393,400)
Asset smoothing adjustment	$0	($59,700)
Smoothed value of assets	$31,843,600	$29,540,500
Going concern funding target		
• Active members	$20,288,900	$25,820,900
• Pensioners and survivors	$15,360,800	$11,632,100
• Deferred pensioners	$423,900	$455,900
Total	$36,073,600	$37,908,900
Funding excess (shortfall)	($4,230,000)	($8,368,400)

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		($8,368,400)
Interest on funding excess (funding shortfall) at 6.10% per year		($510,500)
Employer's special payments, with interest		$906,200
Expected funding excess (funding shortfall)		($7,972,700)
Net experience gains (losses)		
• Net Investment return	$595,300	
• Increases in pensionable earnings	($79,500)	
• Increase in YMPE	($4,900)	
• Increase in maximum pension	$12,900	
• Indexation	$107,200	
• Mortality	($11,300)	
• Retirement	$152,100	
• Termination	($69,300)	
• Net inter-plan transfers	($16,100)	
Total experience gains (losses)		$686,400
Impact of changes in assumptions		
• Discount rate	$2,629,100	
• Indexation rate	$763,600	
• Termination decrement	($162,700)	
Total assumption changes impact		$3,230,000
Impact of change in asset valuation method		$175,800
Net impact of other elements of gains and losses		($349,500)
Funding excess (shortfall) as at current valuation		($4,230,000)

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

	2013	2012
Total current service cost	$728,100	$886,800
Estimated members' required contributions	($46,000)	($52,000)
Estimated employer's current service cost	$682,100	$834,800
Expense allowance	$60,000	$60,000
Total	$742,100	$894,800
Employee's current service cost expressed as a percentage of members' pensionable earnings.	1.97%	1.91%
Employer's current service cost expressed as a percentage of members' pensionable earnings.	30.31%	32.79%
Total current service cost expressed as a percentage of members' pensionable earnings.	32.28%	34.70%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	32.79%
Demographic changes	1.02%
Assumption changes	(3.50%)
Employer's current service cost as at current valuation	30.31%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern funding target shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Going concern funding target	$36,073,600	$42,456,600
Current service cost		
• Total current service cost	$728,100	$895,700
• Estimated members' required contributions	($46,000)	($46,000)
• Estimated employer's current service cost	$682,100	$849,700
• Expense allowance	$60,000	$60,000
Total	$742,100	$909,700

4

Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	12.31.2012	12.31.2011
Assets		
Market value of assets	$32,958,400	$30,993,600
In transit amount	($1,114,800)	($1,393,400)
Termination expense provision	($200,000)	($50,000)
Wind-up assets	$31,643,600	$29,550,200
Present value of accrued benefits for:		
• active members	$16,505,000	$19,322,500
• pensioners and survivors	$20,599,300	$13,684,600
• deferred pensioners	$621,200	$564,100
Total wind-up liability	$37,725,500	$33,571,200
Wind-up excess (shortfall)	($6,081,900)	($4,021,000)

Wind-up Incremental Cost to December 31, 2013

The wind-up incremental cost is an estimate of the present value of the projected change in the hypothetical wind-up liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The hypothetical wind-up incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	12.31.2012	12.31.2011
Number of years covered by report	1 year	1 year
Total hypothetical wind-up liabilities at the valuation date (A)	$37,725,500	$33,571,200
Present value of projected hypothetical wind-up liability at the next required valuation plus benefit payments until the next required valuation (B)	$39,996,900	$35,823,600
Hypothetical wind-up incremental cost (B – A)	$2,271,400	$2,252,400

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a hypothetical wind-up basis unchanged from the valuation date and the next required valuation date, if actual experience is exactly in accordance with the going concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the hypothetical wind-up liabilities shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total hypothetical wind-up liability	$37,725,500	$43,794,300

5

Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	Reflected in valuation based on the terms of engagement
The circumstance under which the Plan is assumed to be wound up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up valuation.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Under the Federal pension legislation, the minimum funding requirements on a solvency basis are based on an alternative solvency basis under which the solvency deficiency and the resulting solvency special payments are based on an average solvency ratio determined over three years (current year plus the previous two) subject to prescribed adjustments. The determination of the solvency deficiency on that basis is detailed in Appendix A. The unadjusted solvency deficiency at the current valuation is presented below.

Financial Position

The financial position on a solvency basis is the same as the financial position on the Hypothetical Wind-up Basis shown in the previous section. The solvency ratio is 83.9% compared to 88.0% at the previous valuation.

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Minimum Funding Requirements

The Act prescribes the minimum contributions that Canadian Utilities Ltd. must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions	
Period beginning	Monthly current service cost[2]	Minimum monthly special payments	Monthly current service cost including expense allowance	Total minimum monthly contributions
December 31,2012	30.31%	$39,090	$61,842	$100,932

The estimated contribution amounts above are based on projected members' pensionable earnings. If current service cost contributions are based on a percentage of members' pensionable earnings, then the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

Alternatively, as the Plan is closed to new employees and therefore the active membership is declining, it would be acceptable to contribute the above dollar amount of total minimum monthly contributions to the Plan.

The development of the minimum special payments is summarized in Appendix A.

Other Considerations

Differences between Valuation Basis

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the

[2] Expressed as a percentage of members' pensionable earnings capped at $150,164 per member.

hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of Contributions

Required contributions must be remitted monthly, not later than 30 days after the end of the period to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution is due immediately following the date this report is filed.

Any over contributions made prior to filing this report may be used to reduce the otherwise required contributions to be made following the filing of this report.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the solvency ratio revealed in an actuarial valuation is less than one. If the solvency ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Specifically, based on the Directives of the Superintendent of Financial Institutions pursuant to the Act, transfers out of the Plan may be made in full provided an amount equal to the transfer deficiency has been remitted to the pension fund in addition to the minimum special payments.

However, transfer deficiencies that are less than 5% of the Year's Maximum Pensionable Earnings ("YMPE") under the Canada/Quebec Pension Plan can be paid in full until such time as the sum of all such transfer deficiencies paid since the date of the last actuarial valuation exceed 5% of the market value of the Plan assets at that date, at which time, this exemption no longer applies.

As such, the administrator should monitor the solvency ratio of the Plan and, if necessary, take the prescribed actions.

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Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. However, notwithstanding the limit imposed by the ITA, for plans which are not 'Designated' as defined in the ITA, in general, the minimum required contributions under the Act can be remitted.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up basis, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up basis, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

The Company is permitted to fully fund the greater of the going concern and hypothetical wind-up shortfalls; $6,081,900, as well as make current service cost contributions. The portion of this contribution representing the payment of the going concern funding shortfall can be increased with interest at 6.10% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

Assuming the Company contributes the greater of the going concern and hypothetical wind-up shortfall of $6,081,900 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions
Year beginning	**Monthly current service cost[3]**	**Deficit Funding**	**Monthly current service cost**
December 31, 2012	30.31%	n/a	$61,842

[3] Expressed as a percentage of members' pensionable earnings capped at $150,164 per member.

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

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Actuarial Opinion

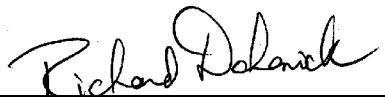
In our opinion, for the purposes of the valuations:

- the membership data on which the valuation is based are sufficient and reliable
- the assumptions are appropriate
- the methods employed in the valuation are appropriate

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pensions Benefits Standards Act*, 1985.

Mark Greenwood
FCIA, FIA

July 30, 2013
Date



Richard Dahonick
ASA

July 30, 2013
Date

APPENDIX A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Going concern excess (deficit)	Amount by which the going concern assets exceed (are below) the going concern liabilities	($4,230,000)
Unfunded liability	The amount by which the going concern deficit of a plan determined at the valuation date exceeds the present value of going concern special payments of the plan established in respect of periods after the valuation date	$0
Going concern special payment	A special payment made in respect of an unfunded liability	$469,100
Solvency Liabilities	Liabilities that relate to defined benefit provisions and which are determined on the basis that the plan is terminated	$37,725,500
Solvency Assets	Market value of the assets that relate to the defined benefit provisions of a plan minus the estimated expense of the winding-up of the plan	$31,643,600
Solvency Ratio	Ratio of the solvency assets to the solvency liabilities, excluding those solvency assets and solvency liabilities that are attributable to benefits that are paid by means of an annuity, other than a revocable annuity, or an insurance contract	0.839
Average Solvency Ratio	Arithmetic average of the solvency ratios at the valuation date, the prior valuation date and the prior second valuation date adjusted as prescribed for special payments, contribution holidays, amendments and transfer of assets	0.984
Adjusted Solvency Asset Amount	Amount determined by multiplying the average solvency ratio by the amount of the solvency liabilities	$37,113,100
Solvency excess (deficiency)	Amount by which the adjusted solvency asset amount exceeds (is below) the solvency liabilities	($612,400)
Solvency special payment	A special payment made in respect of a solvency deficiency	$0

Timing of Next Required Valuation

In accordance with the Act and the Superintendent's Directives, an actuarial report must be prepared annually except where the solvency ratio disclosed in the most recent actuarial report filed under subsection 12(3) of the Act was 1.20 or greater.

Accordingly, the next valuation of the Plan will be required as of December 31, 2013.

Special Payments
Going Concern Basis

The present values, at the current valuation date, of the monthly going concern special payments determined in the previous valuation, are as follows:

Present Value of Going Concern Monthly Special Payments from the Previous Valuation

Type of Deficit	Effective Date	Special Payment	Last Payment	Present Value at the Current Valuation Date
Going concern	December 31, 2006	$9,510	December 31, 2021	$797,200
Going concern	December 31, 2009	$26,430	December 31, 2024	$2,762,800
Going concern	December 31, 2011	$37,200	December 31, 2026	$4,354,200
Total		$73,140		$7,914,200

Since the present value of the going concern special payments, $7,914,200, exceeds the going concern deficit at the valuation date, $4,230,000, the excess shall be used, as per the Act and regulations, to reduce the going concern special payments on a pro rata basis as follows:

Minimum Going Concern Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment	Present Value at the Current Valuation Date
Going concern	December 31, 2006	$5,080	December 31, 2021	$426,100
Going concern	December 31, 2009	$14,130	December 31, 2024	$1,476,600
Going concern	December 31, 2011	$19,880	December 31, 2026	$2,327,300
Total		$39,090		$4,230,000

Solvency Basis

In accordance with the Act and regulations, the solvency excess (deficiency) is defined as the amount by which the adjusted solvency asset amount exceeds (is below) the solvency liabilities. For this purpose, the adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio, adjusted solvency asset amount and solvency excess (deficiency) are determined as follows:

Determination of Average Solvency Ratio

	12.31.2010	12.31.2011	12.31.2012
Solvency assets			
Market value of assets	$29,819,300	$29,600,200	$31,843,600
Termination expense provision	($50,000)	($50,000)	($200,000)
Solvency assets (A)	$29,769,300	$29,550,200	$31,643,600
Present value of special payments made (contribution holiday) (B)			
2011	$421,200	n/a	n/a
2012	$820,400	$862,400	n/a
Solvency assets adjusted for special payments (contribution holiday) (C = A + B)	$31,010,900	$30,412,600	$31,643,600
Solvency liabilities (D)	$25,701,100	$33,571,200	$37,725,500
Adjusted solvency ratio (C / D)	120.7%	90.6%	83.9%
Average solvency ratio (E)			98.4%

Calculation of adjusted solvency asset amount and solvency excess (deficiency)

	12.31.2012
Average solvency ratio (E)	98.4%
Solvency liabilities (F)	$37,725,500
Adjusted solvency asset amount (G = E x F)	$37,113,100
Solvency excess (deficiency) (G – F)	($612,400)

If there is a solvency deficiency, the Act and regulations require that solvency special payments be made in an amount equal to the amount by which the solvency deficiency divided by five exceeds the amount of going concern special payments that are payable during the year.

Minimum Solvency Special Payments

	2013
Solvency deficiency divided by five	$122,500
Going concern special payments	$469,100
Solvency special payments (not below $0)	$0

Total Special Payments

The following minimum monthly special payments must be made to the plan to eliminate any going concern deficit and any solvency deficiency at the valuation date, within the periods prescribed by the Act and regulations.

Minimum Monthly Special Payments

	2013
Going concern special payments	$39,090
Solvency special payments	$0
Minimum monthly special payment	$39,090

APPENDIX B

Plan Assets

The pension fund is held by RBC Investor Services. In preparing this report, we have relied upon fund statements prepared by RBC Investor Services without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2012
January 1	30,993,618
PLUS	
Members' contributions	58,984
Company's contributions	1,805,397
Inter-plan transfers	(1,385,521)
Investment income	1,464,696
Net capital gains (losses)	1,055,203
LESS	
Pensions paid	985,311
Lump-sum refunds	-
Administration fees	48,656
December 31	32,958,410
Gross rate of return[4]	8.20%
Rate of return net of expenses[4]	8.04%

[4] Assuming mid-period cash flows.

The market value of assets shown in the above table is adjusted to reflect in-transit amounts as follows:

	Current Valuation	Previous Valuation
Market value of invested assets	$32,958,410	$30,993,618
In-transit amounts		
• Transfers to Plan 1	($1,114,793)	($1,393,398)
Market value of assets adjusted for in-transit amounts	$31,843,617	$29,600,220

We have tested the pensions paid, the lump-sums paid and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy Target	Actual Asset Mix as at December 31, 2012
Fixed Income	50.0%	46.3%
Canadian equity	25.0%	27.3%
Global equity	25.0%	25.6%
Cash	0.0%	0.8%
	100.0%	100.0%

APPENDIX C

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets.

For the previous valuation, an adjusted market-value method to determine the smoothed value of assets was used. Under this method, 50% of realized and unrealized capital gains (losses) arising during a given year are recognized immediately and the remaining 50% of realized and unrealized capital gains (losses) arising during a given year are spread on a straight-line basis over three years in accordance with the schedule shown in the following table:

Year	Percentage of Gains (Losses) not Recognized
2011:	50% of 2/3
2010:	50% of 1/3
Before 2010	0%

Due to the expectation that the solvency position of the plan will determine the plan's minimum funding requirements in the future, we have discontinued the use of this adjusted market-value method.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to meet the plan's cash flow requirements in respect of accrued benefits and absent additional contributions.

As required under the Act, a funding shortfall will be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost can be expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. As the plan is closed to new members, the current service cost as a percentage of members' pensionable earnings is expected to increase as the average age of the members increases.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	6.10% initially, then 4.00% starting in 2020	6.10% initially, then 3.30% starting in 2020
Explicit expenses:	$60,000	$60,000
Inflation:	2.00%	2.00%
ITA limit / YMPE increases:	2.25%	2.25%
Pensionable earnings increases:	3.25% plus merit and promotion	3.75% until 2012, 3.25% thereafter, plus merit and promotion
Post retirement pension increases:	1.85%	2.00%
Retirement rates:	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55

Assumption	Current valuation	Previous valuation
Termination rates:	None	100% of Plan experience 1983 through 1985
Mortality rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using Scale AA	Fully generational using Scale AA
Disability rates:	None	None
Eligible spouse at retirement:	Based on current marital status	Based on current marital status
Spousal age difference:	Actual age if known (otherwise male 4 years older)	Actual age if known (otherwise male 4 years older)

The assumptions are best estimates with the exception that the discount rate includes a margin for adverse deviations, as described below in the Rationale for Assumptions.

Age Related Tables

Sample rates from the age related tables are summarized in the following table:

Age	Merit and Promotion
20	13.65%
25	6.02%
30	3.08%
35	1.75%
40	1.07%
45	0.70%
50	0.47%
55	0.33%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken the member's 2012 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using two different rates. Prior to 2020, the discount rate is based on the expected investment return on the market value of the fund.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- A margin for adverse deviations of 2.10% after January 1, 2020.

We have also observed that the defined benefit program is closed to new entrants and therefore the requirements under the Act will eventually become dominated by the solvency considerations, which in turn are dominated by annuity purchase rates. The discount rate after 2020 partially reflects this lower rate, as instructed by the Company.

The discount rate was developed as follows:

	Before 1.1.2020	After 1.1.2020
Assumed investment return	6.10%	6.10%
Margin	(0.00%)	(2.10%)
Net discount rate	6.10%	4.00%

Expenses

The explicit assumption is based on the average amount of investment and administrative expenses over the last 3 years.

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on our best estimate of future merit and promotional increases over general wage growth considering current economic and financial market conditions. Such merit and promotion increases are assumed to be in accordance with the table developed based on an experience study considering increases over the years 1985 to 1992 and which has continued to be reasonably predictive of merit and promotion increases experienced since that time.

Post Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above, considering that the Plan limits pension increases to 3% in the event that inflation exceeds 3%. We have determined the impact of this cap by performing a stochastic analysis based on trials using a mean of 2.0% and a standard deviation of 1.5%.

Retirement Rates

For this valuation we have continued to assume that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately. This assumption is based on the Plan provisions and our experience of similar pension plans.

Retirement earlier than assumed will result in losses to the Plan, while later retirements will result in gains to the Plan. These gains and losses will be revealed in subsequent valuations.

Termination Rates

As the Plan is closed, most active members are now eligible for retirement. The termination decrement assumption no longer has a material impact on the Plan's funding.

Mortality Rates

Due to the size of the Plan, there is no meaningful mortality experience but there is no reason to expect the mortality to differ from the 1994 Uninsured Pensioners mortality table. Furthermore, there is strong evidence of continuing improvement in mortality since 1994 and it has become an industry standard to assume this trend continues into the future. We have used the AA projection scale to allow for improvements in mortality indefinitely in the future.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 19.8 years for males and 22.0 years for females.

Emerging information from in-progress mortality experience analysis suggests that mortality has recently improved faster than estimated by projection scale AA. However, no standard tables have been published to replace the 1994 Uninsured Pensioners mortality table and projection scale AA for Canadian pension plan purposes. We expect that the mortality assumption will be changed in the first valuation of the plan prepared following publication of alternative mortality tables and projection scales, based on Canadian experience.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on actual membership data, which we believe is the most reliable source.

Spousal Age Difference

Actual spouse age is used where available, otherwise males are assumed to be 4 years older than their spouse.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

There are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. In particular, there are no additional benefits that would be immediately payable if the employer's business were discontinued on the valuation date. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. Therefore, no benefits payable on plan wind-up were excluded from our calculations.

Upon plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries Standards of Practice applicable for December 31, 2012.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2012 and December 30, 2013.*

However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2012 and December 30, 2013*, we have assumed that an appropriate proxy for estimating the cost of such purchase is using the yield on the long-term Government of Canada Real Return bonds.
Interest rate assumptions net of COLA used for lump sum transfers and annuity purchases take into consideration the 3% cap on pension increases provided by the plan provisions. We have

carried out a stochastic analysis in order to determine the additional net interest rate as a result of this 3% cap.

We have not included a provision for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum	70% of active members under age 55 and 50% of active members over age 55 elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	UP94 generational
Interest rate:	2.40% per year for 10 years, 3.60% per year thereafter
Interest rate net of COLA:	1.10% per year for 10 years, 1.50% thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	UP94 generational
Interest rate:	2.96% per year
Interest rate net of COLA:	0.60% per year
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan based on the eligibility requirements which have been met at the valuation date
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Termination expenses:	$200,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for expenses that may reasonably be expected to be paid by the pension fund under the postulated scenario between the wind-up date and the settlement date.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members retire and die consistent with the retirement and mortality rates used for the going concern valuation.
- Pensionable earnings, the *Income Tax Act* pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.
- Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis.

The solvency position is determined in accordance with the requirements of the Act.

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2012, provided by Canadian Utilities Ltd.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2012	31.12.2011
Active Members		
Number	28	33
Total pensionable earnings for the following year	$2,915,007	$3,452,193
Average pensionable earnings for the following year	$104,107	$103,794
Average years of pensionable service	24.9	24.7
Average age	54.2	53.9
Deferred Pensioners		
Number	5	5
Total annual pension	$53,017	$53,017
Average annual pension	$10,603	$10,603
Average age	51.9	50.9
Pensioners and Survivors		
Number	39	35
Total annual lifetime pension	$1,077,857	$833,232
Average annual lifetime pension	$27,637	$23,807
Average age	72.7	73.2

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Deferred Vested	Pensioners and Survivors	Total
Total at 31.12.2011	33	5	35	73
Transfers from Plan 1				
Transfers to Plan 1	(1)			(1)
Terminations:				
• Lump sums				
• Deferred pensions				
Deaths			(1)	(1)
Retirements	(4)		4	0
Survivors			1	1
Total at 31.12.2012	28	5	39	72

The distribution of the active members by age and pensionable service as at December 31, 2012 is summarized as follows:

	Years of Pensionable Service									
Age	**1-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35-39**	**40 +**	**Total**
< 25										
25 - 29										
30 - 34										
35 - 39										
40 - 44				1	3					4
45 - 49		1		1	1	1				4
50 - 54					2	1	3			6
55 - 59				1	2	3	2			8
60 - 64					2		1		1	4
65 - 69					1	1				2
70+										
Total	0	1	0	3	12	5	6	0	1	28

The distribution of the inactive members by age as at December 31, 2012 is summarized as follows:

	Deferred Pensioners		Pensioners and Survivors	
Age	**Number**	**Average Pension**	**Number**	**Average Pension**
< 45				
45 – 49	2	$4,440		
50 – 54	1	$26,351	1	$79,562
55 – 59	2	$8,893	2	$49,101
60 – 64			4	$38,841
65 – 69			9	$26,707
70 – 74			8	$25,095
75 – 79			4	$25,985
80 – 84			8	$19,086
85 – 89			3	$15,660
90 – 94				
95 – 99				
100 +				
Total	5	$10,603	39	$27,637

APPENDIX F

Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Canadian Utilities Ltd.. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2012. The following is a summary of the main provisions of the Plan in effect on December 31, 2012. This summary is not intended as a complete description of the Plan.

Background	The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC). Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Service under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets. Effective December 30, 2003, the Plan was extended to cover employees located in Ontario.
Eligibility for membership	The Plan is closed to new entrants. Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.
Employee Contributions	Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month following the member's 65th birthday. Early Retirement Date • If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.
Postponed Retirement	A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to his actual retirement.

Normal Retirement Pension	2% of annual final average earnings times years of pensionable service between January 2, 1962 and January 2, 1966; PLUS 1.4% of annual final average earnings up to the YMPE, times years of pensionable service after January 2, 1966; PLUS 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service after January 2, 1966.
Pensionable earnings	Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.
Early Retirement Pension	If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows: • if age and service sum to 90 years or more, no reduction applies; • otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:

Age at Retirement	Percentage
64	100
63	100
62	100
61	97
60	94
59	88
58	82
57	76
56	70
55	64

If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.

- In addition, female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable only until age 65. The bridge benefit is equal to the expected Canada Pension Plan benefit times the ratio of 36 divided by the number of months from retirement to age 65, provided that the ratio is never more than 1.

Maximum Pension	The Plan provides that the pension payable at the time of commencement must not exceed: • the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years) Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the ITA and Regulations.

Cost of Living Adjustments	The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid. The annual adjustment is granted to members who retired from active service.
Death Benefits	Pre-retirement: • If a member dies before becoming eligible for retirement, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. • If a member dies after becoming eligible for retirement, the member's spouse will receive the greater of: • a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value, and • an immediate pension equal to 60% of the pension to which the member would have been entitled had the member retired on their date of death. This pension will also receive future cost of living increases. • If a member dies after becoming eligible for retirement and there is no surviving spouse, the beneficiary will receive the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. Post retirement: • The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date • For employees with an eligible spouse, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.
Termination Benefits	A deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

APPENDIX G

Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2012 of the Retirement Plan For Employees of Canadian Utilities Limited and Participating Companies – Plan 2, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Canadian Utilities Ltd. engagement with the actuary described in section 2 of this report, particularly the requirement to include a margin of 2.10% after January 1, 2020 in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2012 were provided to the actuary and are reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarised in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2012.
- All events subsequent to December 31, 2012 that may have an impact on the Plan have been communicated to the actuary.

JUNE 28/13
Date

Signed

ERHARD KIEFER
Name

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The Yukon Electrical Company Limited
Breakdown of Pension Costs 2008-2015

	GRA Forecast 2008	Actual 2008	GRA Forecast 2009	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
Defined Contribution	-	-	-	-	87	113	106	112	114	118
Defined Benefit										
Current Service	441	428	467	466	368	377	401	410	403	403
Special Payments	-	-	-	-	205	211	406	415	408	408
	441	428	467	466	573	588	807	824	812	812
Pension Included in Schedule 5.1	441	428	467	466	660	701	913	936	926	930
Capitalized Pension	139	192	148	186	253	307	521	504	521	523
Total Pension	580	620	615	652	914	1,008	1,434	1,440	1,446	1,452
O&M %	76%	69%	76%	71%	72%	70%	64%	65%	64%	64%
Capitalized %	24%	31%	24%	29%	28%	30%	36%	35%	36%	36%
Total %	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

The Yukon Electrical Company Limited
Operations and Maintenance Expenses - Excluding Pension

Line No.	Description	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
1	**Production**								
2	62600 - Hydro Generation	87	116	105	100	141	299	379	413
3	64000 - Supervision and Engineering Diesel	53	54	55	54	58	54	56	58
4	64600 - Diesel Generation	332	395	441	546	401	473	660	671
5	82600 - Hydro Maintenance	47	31	19	60	103	47	48	49
6	84600 - Diesel Maintenance	1,002	970	864	966	1,131	1,159	1,182	1,206
7		1,521	1,566	1,483	1,725	1,833	2,031	2,325	2,396
8	**Distribution**								
9	87000 - Supervision	219	251	207	213	224	259	268	277
10	87100 - Brushing	322	326	349	277	534	395	404	412
11	87200 - Vehicle Depreciation	(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
12	87300 - Maintenance	1,251	1,566	1,593	1,629	1,705	1,768	1,821	1,912
13	87310 - Service to Outside Parties	70	83	64	90	101	103	105	107
14	87400 - Underground Line Maintenance	96	111	87	81	182	150	155	177
15	87500 - Meter and Meter Testing	151	113	85	94	105	84	87	90
16	87700 - Transformer Repair and Replacement	29	11	35	46	105	71	73	78
17	87800 - Street Light Maintenance	161	156	159	151	167	177	182	194
18		2,203	2,477	2,427	2,419	2,954	2,823	2,907	3,056
19	**General**								
20	88400 - Communication	8	17	9	10	15	12	13	13
21	88800 - Maintenance Company-Owned Houses	32	11	17	16	16	17	17	18
22	88900 - Maintenance Warehouse and Office	108	113	122	115	146	129	131	134
23		148	141	149	140	177	158	161	164
24	**Public Information**								
25	70100 - Public Information Administration	85	70	42	32	25	24	25	26
26	70200 - General Public Information	17	49	56	69	97	109	113	116
27		102	119	98	101	122	134	138	142
28	**Customer Accounting**								
29	71000 - Supervision	27	49	36	29	44	44	46	48
30	71100 - Customer Applications and Service Orders	326	410	365	359	373	406	438	468
31	71200 - Meter Reading	495	508	482	413	419	492	507	449
32	71300 - Customer Billing and Accounting	549	685	669	678	664	717	734	758
33	71400 - Revenue Collections	189	160	142	145	149	190	197	203
34	71500 - Collection of Delinquent Accounts	120	89	105	96	102	118	122	126
35	71800 - Provision for Uncollectible Accounts	36	34	43	36	36	36	36	36
36		1,741	1,934	1,843	1,757	1,786	2,004	2,079	2,088
37	**Administration and General**								
38	72100 - Administrative	1,453	1,446	1,552	1,692	1,921	2,171	2,318	2,315
39	72200 - Administrative Corporate	27	149	184	71	196	135	137	140
40	72300 - Insurance	207	228	215	244	245	262	202	138
41	72400 - Injuries & Damages	75	97	86	86	86	124	124	125
42	72500 - Employee Expenses	220	226	244	239	232	262	267	274
43	72600 - Training and Safety	288	377	363	345	390	407	419	435
44	72700 - Relocation	108	51	213	204	65	158	161	168
45	72800 - Miscellaneous General	3	-	-	-	-	-	-	-
46	72900 - Audit/Legal Fees & Special Studies	69	198	109	76	140	131	154	137
47		2,450	2,771	2,965	2,956	3,274	3,650	3,783	3,731
48									
49	**Total Operations and Maintenance Expenses - Excluding Pension**	8,165	9,008	8,965	9,098	10,146	10,799	11,393	11,577
	Total Pension Expense	428	466	660	701	913	936	926	930
	Total Operations and Maintenance Expenses - Including Pension	8,593	9,474	9,625	9,799	11,059	11,735	12,319	12,507

YUB-YECL-6

Reference: Affiliate Costs, YECL Application, page 5-4, YECL Application, Schedule 5-3

Yukon Electrical outsources certain major administrative functions to affiliate companies, such as ATCO Electric, to take advantage of the economies of scale of services available from a larger utility. The cost of these services is detailed in Schedule 5.3 and is based on a fully allocated cost methodology that does not contain any element of profit or return.

The Board wants to better understand the allocated cost methodology used by YECL and its affiliates.

Request:

(a) Please describe the fully allocated cost methodology that YECL and affiliate companies use to determine how costs are allocated.

(b) Please explain whether the cost allocation methodology has changed since 2008.

(c) Please explain the increases in affiliate charges in Account 87500 – Meters and Meter Testing. Are the increases in affiliate charges due to the rate charged or the volume of work? If due to volume, provide an explanation for these volume increases.

(d) What type of metering services does ATCO Electric provides to YECL?

(e) Please explain the increases in affiliate charges in Account 87000 – Supervision. Are these increases due to the rate charged or the volume of work? If due to volume, provide an explanation for these volume increases. In particular, explain why the costs to answer calls after hours will double from 2012 to the test period

(f) What type of meter services does ATCO Gas provide to YECL?

(g) Please explain the increases in affiliate charges in Account 72100 and Account 71300. Are the increases in affiliate charges due to the rate charged or the volume of work? If due to volume, please provide an explanation for these

volume increases. In particular, address the increases related to Rates and Terms & Conditions, Financial Reporting and Regulatory Support, and Payroll, Use of Systems and IT.

(h) With regard to affiliate services provided by ATCO I-Tek, please indicate whether YECL is charged the same rate by ATCO I-Tek as other ATCO affiliates. If the rate is different, explain why it is different. Please provide evidence that the affiliate services received by YECL are at a cost/price that is lower than can be internally provided or at a cost/price that is less than can be obtained locally.

(i) With regard to Account 64600 – Diesel Generation, please describe the services that ATCO Gas provides to YECL in more detail. Can YECL confirm that ATCO Gas is the cheapest provider for these services and by what method has YECL made this determination?

(j) Account 87000 shows $62,000 for After Hours – Call Answering. Please provide details for these costs and explain why these costs have almost doubled from 2012 to 2013.

Response:

(a) Please refer to YUB-YECL-6(a) Attachment 1 for a complete description of the fully allocated cost methodology.

(b) There have been no changes to the cost allocation methodology since 2008.

(c) ATCO Electric provides Yukon Electrical with metering services which include: supplying new and used meters, testing, verifying and re-sealing the meters as well as performing load and loss research studies. Costs increases are due to both volume (with increased customer growth and meters) as well as labour inflation for ATCO Electric.

(d) ATCO Electric is a federally accredited (Measurement Canada) revenue meter testing facility. Through the Revenue Metering department, Yukon Electrical ensures compliance with Measurement Canada with regard to revenue meter testing, quality assurance conformity and audits. The ATCO Electric Metering department maintains Yukon Electrical's meter records system and ensures the records are available for review and inspection by representatives of Measurement Canada. ATCO Electric Meter department also orders, catalogs,

manages and maintains all inventory of revenue metering for Yukon Electrical. Yukon Electrical utilizes the ATCO Electric Meter Standards Manual for installation, testing and use of revenue metering that ensures compliance to all applicable regulations and standards.

(e) While Yukon Electrical has seen modest increases in the amount of calls being covered by AHA, the major reason for the step increase between 2012 and 2013 is due to ATCO Electric completing a detailed usage review of AHA services in 2012. This review determined Yukon Electrical's fair share of costs based on usage needed to be increased to reflect what was actually taking in place. In essence, Yukon Electrical was under charged by ATCO Electric for this service in 2012.

In summary, the reasons for the increase between 2012 and 2013 are as follows:

- Completion of an updated activity based costing methodology;
- An increase in the coverage provided from 5 PM – 8:00 AM weekdays to 4 PM – 8 AM weekdays;
- Increasing volume of after hour calls.

(f) ATCO Gas provides the Data Capture System and the Field Collection System that processes and manages Yukon Electrical's meter reading routes and information. The Field Collection System links the meter readings to ATCO CIS (billing system) and the appropriate customer accounts. The system also produces billing estimates for routes and accounts. ATCO Gas produces reports of meter reads outside set parameters such as high/low read and high/low consumption.

(g) The charges for Rates and Terms & Conditions are for services provided by ATCO Electric staff for supporting rate and rider design, supporting consultations with customers, responding to questions on rate related matters and supporting the development of a sales forecast. The forecast costs are increasing as a result of an increase in the volume of services charged, from approximately 0.1FTE to 0.2FTE, to better reflect the actual as well as forecast time being incurred by staff for Yukon-related issues.

The volume of services for Financial Reporting and Regulatory Support has increased as a result of the addition of the Corporate Accountant and Manager, Financial Reporting & Accounting, North of 60 positions in 2012, as well as the relocation of the Supervisor, Financial Services position from Whitehorse to Edmonton in 2011. As these services are charged based on the actual labour rates paid to the employees providing the services, and employees receive annual increases, the rates charged increase annually based on labour inflation. Please refer to YUB-YECL-22(j) and (k) for further details on the need for these positions.

The charges for Payroll, Use of Systems and IT have increased due to both a change in rate as well as an increased volume of services. The Payroll services are changed based on a flat rate per employee per pay. The rate charged has not changed since 2010 but the volume of services has increased as a result of the increase in the Yukon Electrical complement. The charges for Use of Systems are for the use of software such as Oracle and Hyperion Financials. The volume of services has increased as a result of the increase in the Yukon Electrical complement. As well, it was discovered in late 2011 that Yukon Electrical was not paying a share of all software which it utilizes. This was corrected in late 2011, resulting in an increase in charges for 2012.

The increases for account 71300 in 2013 are due to volume increases as well as costs for various billing system special requests (e.g. modifications to reports, special extracts of data, changes to rider names, etc.) which are typical for a given year based on prior year averages. Rates are not forecast to increase until 2015. Please refer to YUB-YECL-6(g) Attachment 1 for a schedule of Volumes and Rates.

(h) Yukon Electrical is charged the same rate by ATCO I-Tek for information technology (IT) services as is charged to all other ATCO affiliates. Including ATCO Electric, Northland Utilities (Yellowknife) and Northland Utilities (NWT). The rates charged for information technology to the regulated utilities in Alberta are currently under review by the Alberta Utilities Commission to ensure they are charged at fair market value. Given the high degree of IT integration Yukon Electrical has with its parent, it would not be possible to choose a local supplier, even if one was available, for these services. On the question of choosing to providing these services internally on a stand-alone basis and not taking advantage of the economies of scale afforded due its relationship with its

parent and affiliates, Yukon Electrical does not believe it would be able to keep its total "all in" IT costs below the current forecast of under ½ million per year.

With respect to Billing System Services (ITBS), Yukon Electrical is charged the same rate as its Northland affiliates as the services provided are the same. These ITBS costs were reviewed extensively as part of the 2008-2009 GRA proceeding when Yukon Electrical brought forward the forecast costs of a new billing system. The Board accepted the costs for the new billing system as part of Board Order 2009-2. No material changes to the system or costs have occurred since that point in time. There is no local supplier that would be able to provide these services.

(i) Yukon Electrical presently has a provider to supply diesel fuel for use in the Watson Lake Power Plant. Yukon Electrical has the expertise to utilize a new fuel and requires a supply of natural gas at the plant site to implement the bi-fuel project.

This project is the first of its kind and will be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and that the performance of the entire facility is acceptable.

ATCO Gas's services to provide natural gas include liquefied natural gas (LNG) storage and vaporization services along with their expertise related to systems design, purchasing, installation, commissioning, on-going operations support, maintenance, permitting, licensing for the project, regulator support, Health Safety and Environment policies, procedures and work instructions, regulations and safety. The equipment includes an LNG Facility comprised of on-site storage of LNG, LNG vaporizer and controls, natural gas odorizer, metering and facility safety systems.

Yukon Electrical has structured the project to allow flexibility with respect to capital commitments and provision of necessary expertise that allows Yukon Electrical to if necessary, exit the project without having invested the full capital required. This allows Yukon Electrical to evaluate on a go-forward basis the contractual arrangement for equipment and services. The cost of equipment is one part of the lease arrangement. Yukon Electrical has taken the lease approach to secure an inclusive expert provider of natural gas rather than a consortium of consultants, equipment providers and specialized service providers. This bundled approach with ATCO Gas to provide natural gas

includes LNG storage and vaporization services along with their expertise related to systems design, purchasing, installation, commissioning, operations support, maintenance, permitting, regulations and safety. The equipment being utilized is secured utilizing ATCO Gas' competitive procurement process that involves engineering, financial and purchasing professionals. Yukon Electrical is involved in each step of the development of this system to ensure appropriate procurement methods are used and that cost expenditures are prudent.

A competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012. At that time, there were also no regulations, permits or procedures in the Yukon related to this unique project. Yukon Electrical has continued to investigate comparative benchmark pricing related to other service providers that may become available.

(j) Please refer to part (e) of this response regarding after-hours call answering.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

PURPOSE

To provide guidelines for the charging of work performed for or received from affiliates within the ATCO Group.

POLICY

- All transactions with affiliates are governed by the ATCO Group Inter-affiliate Code of Conduct.

For Profit Services

- Services provided to Affiliates on a For Profit Basis shall not be charged at less than the Fair Market Value for those services. Services received from Affiliates on a For Profit Basis shall not be paid for at more than Fair Market Value. Consultation with the Compliance Officer should occur prior to the determination of Fair Market Value for services to be provided or received on a For Profit Basis.

- A prudence review of these services may be required when deemed appropriate by management and / or the Compliance Officer. In demonstrating that Fair Market Value was paid or received pursuant to a For Profit Affiliate Service arrangement, the Utility, subject to any prior or contrary direction by the AUC, may utilize any method to determine Fair Market Value that it believes appropriate in the circumstances. These methods may include, without limitation: competitive tendering, competitive quotes, benchmarking studies, catalogue pricing, replacement cost comparisons or recent market transactions.

- The Utility shall bear the onus of demonstrating that the methodology or methodologies utilized in determining the Fair Market Value of the subject goods or services was appropriate in the circumstances.

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PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

Shared Services

- Shared Services provided to or received from Affiliates on a Cost Recovery Basis are permitted, unless an approved regulated rate exists for the services, in which case the regulated rate will be charged. In the event that the service provided represents a major on-going transaction, or a collection of related minor transactions that are significant in their totality, a review, involving the Compliance Officer, should be performed as to whether the service pricing is appropriate.

- Financial transactions with Affiliates — A Utility shall ensure that any loan, investment, or other financial support provided to a Non-Utility Affiliate is provided on terms no more favorable than what that Non-Utility Affiliate would be able to obtain as a standalone entity from the capital markets.

- Sharing employees — A Utility may share employees on a Cost Recovery Basis with an Affiliate provided that the employees to be shared:
  i) do not have access to Confidential information;
  ii) do not routinely participate in making decisions with respect to the provision of Utility Services or how Utility Services are delivered;
  iii) do not routinely deal with or have direct contact with customers of the Utility; and
  iv) are not routinely involved in operating, planning or managing the business of the Utility (subject to certain exceptions per the Code).

- Transferring of employees — A Utility may transfer employees to or from an Affiliate, provided **any** employee transferred by the Utility who had access to Confidential Information shall execute a confidentiality agreement with respect to such Confidential Information prior to the transfer.

- Sharing of assets - The plant, assets and equipment of a Utility shall be separated in ownership and separated physically from the plant, assets and equipment of other Non-Utility Affiliates. Utility Affiliates may share ownership and may physically share office space, equipment, rights-of-way and other assets on a Cost Recovery Basis.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

- Where operational efficiencies between Utilities that are Affiliates can be obtained through the use of common facilities (such as shared warehousing or field offices). combined purchasing power or through the use of other cost saving procedures, individual assets or groups of assets used in Utility operations (such as equipment, plant inventory, spare parts or similar assets) may be transferred in the ordinary course of business between Utilities on a Cost Recovery Basis.

- Occasional Services: A Utility may receive, or provide, one-off, infrequent or occasional services to or from an Affiliate on a Cost Recovery Basis, without a service agreement. The service(s) must be documented by way of a work order, purchase order or similar instrument.

- Emergency Services: In the event of an emergency, a Utility may share services and resources with an Affiliate without a service agreement on a Cost Recovery Basis. The service(s) must be documented by way of a work order, purchase order or similar instrument.

Master Service Agreement or Contract

- A Master Service Agreement or Master Service Contract (both referred to as MSC for purposes of this policy) must be developed with each affiliate, governing all services with the affiliate, which are not charged on the basis of regulated rates. All services with the affiliate counter party that the MSC applies to can be brought under that MSC by way of a schedule to the MSC. A copy of all agreements with affiliates should be forwarded to the Compliance Officer for record keeping. Note that a service agreement is not required for occasional or emergency services. in the event that these services become material as to value, frequency or use of resources, (as determined by management or the Compliance Officer), a service agreement shall be entered into.

Recoveries

- Recoveries for work performed for affiliates will be recorded as revenue to ATCO Electric, not as a reduction to operating expenses.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

DEFINITIONS

Affiliate: Means with respect to any Utility:

i) an affiliate as defined in the Alberta Business Corporations Act;

ii) a unit or division within the Utility or any Body Corporate referred to in clause (i) above;

iii) a partnership, joint venture, or Person in which the Utility or any Body Corporate referred to in clause (i) above has a controlling interest or that is otherwise subject to the control of the Utility or such Body Corporate;

iv) any partnership, joint venture, or Person deemed by the AUC to be an affiliate of the Utility for the purpose of this Code of Conduct; and

v) an agent or other Person acting on behalf of any Body Corporate, operating division, partnership, joint venture or Person referred to in clauses (i) to (iv) above.

Cost Recovery Basis: Means with respect to:

i) the use by one Affiliate of another Affiliate's personnel, means the fully burdened costs of such personnel for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads;

ii) the use by one Affiliate of another Affiliate's equipment, means an allocated share of capital and operating costs appropriate for the time period utilized by the Affiliate;

iii) the use by a Utility of an Affiliate's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently;

iv) the use by an Affiliate of a Utility's services, means the complete costs of providing the service, determined in a manner acceptable to the Utility, acting prudently; and

v) the transfer of equipment, plant inventory, spare parts or similar assets between Utilities, means the net book value of the transferred assets.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
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Direct Labour Costs: The number of hours worked on a project times an employee's hourly wage, or the portion of the annual salary attributable to the services provided.

Direct Costs of Goods and Services: The actual amount paid to the vendor for supplies and services used in the provision of services to an affiliate.

Direct Cost of Material: The unit cost of material used in the provision of services to an affiliate based on the average cost from the Materials Management System.

Direct Cost of Vehicle and Equipment Charges: The charges for vehicles and equipment used in the provision of services to affiliates should be based on the hours used times the hourly charge out rate. The hourly charge out rate will include capital and related costs.

Fair Market Value: The price reached in an open and unrestricted market between informed and prudent parties, acting at arms length and under no compulsion to act.

For Profit Services: Any service that relates to a core business provided on a for-profit bases:

i) by a Utility to a Non-Utility Affiliate, other than a Utility Service; or
ii) by a Non-Utility to a Utility.

Fringe Benefits: The costs incurred by the employer in providing benefits to the employee. These costs include: CPP, Pension, Employment Insurance, Workers' Compensation, Alberta Health Care.

Non-Preset Labour: Employees who are not preset and must submit a daily timesheet in order to distribute their salary to the appropriate accounts.

Preset Labour: Employees whose salaries are distributed on a preset basis to the same accounts.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

Payroll Burden: An incremental charge that is included in an employee's hourly charge out rate to cover payment for statutory holidays and vacation pay.

Overhead: A general loading charge applied to all Labour Costs for the recovery of corporate costs.

PROCEDURE

A. Determination of Cost Recovery Basis.

- Charges for services should be done on an actual cost basis providing it is cost effective and reasonable to track the cost of services provided. In the event cost tracking is not used, the cost allocation methodology used must fairly allocate costs based on reasonable and appropriate criteria. Whether cost tracking is used or not, the following amounts must be incorporated in the determination of fully burdened costs:

  1. Labour Charges — In addition to the Direct Labour Costs, the following amounts should be included:

     - Payroll Burden of 16.3% for employees on timesheets. The payroll system will apply the burden for all Non-Preset Labour. The burden rate is not to be applied when an annual salary is used in the determination of the Direct Labour costs. A separate calculation of burden will be made for Preset Labour charged on an hourly basis.

     - Fringe Benefits — Fringe Benefits are determined by the financial system on a monthly basis.

     - For non-construction projects an Overhead rate of 60% will be applied to labour charges, including payroll burden where applicable as defined above. An additional Overhead rate of 20% will be applied to the labour charges including payroll burden for construction projects.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
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- Other charges as discussed below must be included as applicable.

2. Other Charges which may or may not apply, depending on the service performed include:

- Direct cost of Goods and Services.

- Direct Cost of Material — a handling and restocking charge will be applied to the direct cost of materials. Contact Financial Reporting for the current rate to be applied. The MSC should contain a provision that allows for this rate to be varied by ATCO Electric as required.

- Direct Cost of Vehicle and Equipment Operating Costs — Contact Financial Reporting for the current rates to be applied. The MSC should contain a provision that allows for this rate to be varied by ATCO Electric as required.

- Financing, operating costs and depreciation should be recovered if the provision of service to an Affiliate involves the use of ATCO Electric's utility assets. Contact Financial Reporting for assistance in determining these amounts.

- Financing costs associated with a delay in compensation for a material portion of the agreement may be required. Contact Financial Reporting for assistance in determining these amounts.

3. If the agreement involves the disposal of an asset, then fair market value will be exchanged for the asset. If the sale of an asset occurs between regulated affiliates, Fair Market Value will not be less than the Net Book Value of the assets. Statutory requirements for regulatory approval of sales of utility property, other than in the ordinary course of business, will be met.

ATCO ELECTRIC LTD. ACCOUNTING POLICY MANUAL	Provision of Services to or from Affiliates
Original Issue Date: Nov 2, 2001	**Revision Date:** April 10, 2007 **Number:** G.5
PREPARED BY: D. Freedman	**APPROVED BY:** Dennis DeChamplain

B. Finalizing the Agreement

1. The standard MSC is to be used for all agreements with non-regulated affiliates. In the event that a modification to the format of the MSC is required, approval must be obtained from the Compliance Officer.

2. Where an MSC is required, a new MSC must be developed or the existing MSC amended to incorporate new services or changes to pre-existing services. The amendment can be incorporated through the revision to Schedules of the MSC, with appropriate approvals from all parties to the agreement, as well as an approval date.

   The new or amended agreement must clearly indicate an effective date. Contact the Compliance Officer for assistance with respect to this.

3. Discussion with Financial Reporting should occur regarding how the revenue is to be collected, and any new account numbers required for the tracking of revenues and costs associated with the agreement. Generally affiliate revenues should be processed through debit notes which have a standard settlement date. Other collection methods may require a bill to be generated or different procedures to be put in place.

C. Compliance Records

- Records shall be maintained in a manner sufficient to support a third party audit of the state of compliance with the ATCO Group Inter-Affiliate Code of Conduct and retained for a period of at least six years.

	Volumes				Rate				Costs			
	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
Base/Incremental Billing, Addl.Serv												
Base Fee Metered	206,558	210,586	214,018	217,614	$ 1.72	$ 1.72	$ 1.72	$ 1.75	$ 355,280	$ 362,208	$ 368,112	$ 380,824
Base Fee Non-Metered	7,599	7,747	7,873	8,006	$ 1.02	$ 1.02	$ 1.02	$ 1.04	$ 7,751	$ 7,902	$ 8,031	$ 8,326
Incremental Billing, Printing per page	199,063	202,945	206,253	209,718	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 23,888	$ 24,353	$ 24,750	$ 25,166
Price Schedule Value Chg Rate/Rider	1.16	1.18	1.20	1.22	$ 1,973.50	$ 1,973.50	$ 1,973.50	$ 1,973.50	$ 2,289	$ 2,329	$ 2,368	$ 2,408
Passthrough												
Paper									10,054	10,455	10,838	11,240
Postage									111,189	115,624	119,859	124,310
Billing System Special Requests (1)									8,550	23,000	23,000	23,000
									519,001	545,871	556,958	575,274

(1) 2009-2012 Average $23,000

YUB-YECL-7

Reference: Discontinuance of Third Party Distribution Line (Property Insurance), YECL Application, page 5-5, YECL Application, Schedule 5-1

Yukon Electrical is proposing to discontinue purchased third party distribution line (property) insurance at the end of the 2013/2014 insurance period, July 1, 2014. On a go forward basis, insurable losses during construction or operations, if and when they occur, would be charged to the Reserve for Injuries and Damages.

The Board requires more details regarding YECL's plan.

Request:

(a) Please describe YECL's current RFID policy.

(b) Please explain how the proposed change will affect YECL's RFID policy and practices (e.g. will appropriations increase?).

Response:

(a) Yukon Electrical seeks to obtain insurance coverage except in cases where the exposure risk is minimal or the cost of the insurance is prohibitively high. In the case of an insured loss, amounts charged to the RFID would include the deductible portion of insured losses as well as any portion of the claim not paid by the insurance company. In the case of an uninsured loss where coverage was not obtained or was not available as a result of very high-risk exposure, the entire amount of the loss would be charged to the RFID. Please also refer to Section 8 Attachment 1 of Yukon Electrical's Application.

(b) The proposed change will not change Yukon Electrical's RFID policy. Yukon Electrical believes that the cost of the third party distribution line insurance, approximately $127,000 per year, is high for the amount of coverage provided, which is a limit of $1.5 million with a $1.0 million deductible. Additionally, there have not been any claims on the third party distribution line (property) insurance policy for the past 20 years.

YUB-YECL-8

Reference: Account 62600 – Hydro Generation, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 62600 – Hydro Generation

Request:

(a) Please explain in more detail the specific environmental costs related to the Fish Lake water licensing process which caused the cost increase in 2012.

(b) Please describe in further detail the drivers for the increased inspection and maintenance that resulted in $60,000 of cost in 2013.

(c) Please describe in further detail the specifics of the costs related to the Fish Lake water licensing process that resulted in $106,000 of cost in 2013.

Response:

(a) Please refer to YUB-YECL-8 Attachment 1. The specific environmental costs in O&M relate to various projects performed by contractors as well as increased labour and fringe.

(b) The increased 2013 inspection and maintenance costs are a result of the requirements of the new licence (please refer to YUB-YECL-8 Attachment 1).

(c) Please refer to YUB-YECL-8 Attachment 1 for a description as well as details on the specific costs.

The Yukon Electrical Company Limited
Breakdown of Account 62600 - Hydro Generation

	Actual	Actual	Test Period		
	2011	2012	2013	2014	2015
Labour *	64	75	124	216	233
Fringe Benefits	12	19	30	57	61
Contractor Services (Note 1)	20	44	152	131	146
Other	12	16	14	15	15
Schedule 5.1 Line 2	108	154	320	419	454

* The labour for 62600 for 2014 and 2015 includes 100% of the costs related to the Environmental Technician position to be added in 2014. This position will not be exclusively working on environmental monitoring and compliance related to hydro generation but will also be working on diesel generation. As a result, Yukon Electrical proposes to reclassify 50% of the costs related to the Environmental Technician position to account 64600.

Note (1) Contractor Services Breakdown:

Fish Lake Intake Inspection	1				
Beaver Dam Removal	2				
Flow Monitoring	6				
Low Flow Testing	5				
Fish Stranding Report	1				
Other	6				
	20				
Beaver Dam Removal		3			
Spillway Fish Salvage - Louise Lake		19			
Jackson Creek Studies		2			
Geotechnical Study		4			
Other		17			
		44			
	Source	*Frequency*			
OMS Revisions	License Requirement	Annually	6	6	6
Adaptive Management Plan Franklin Lake Monitoring	License Requirement	Annually until 2017	2	2	2
Annual Inspection Report	License Requirement	Annual except 2015	10	10	-
Canada Dam Safety Review	License Requirement	July or Aug 2015	-	-	25
Water Quality Sampling in Late Summer at Franklin Lake	License Requirement	Annual until 2018	3	3	3
Fish Age and Abundancy Study for Louise and Franklin Lake	License Requirement	Annual until 2018	7	7	7
Fish Population Study Head Pond #2	License Requirement	Annually	2	2	2
Bird Nesting/Brooding Survey Fish Lake	Inspection & Maintenance	Annual until 2018	10	10	10
First Nations Land Tenure, Access and Monitoring	Inspection & Maintenance	Annual	84	65	66
Other			28	26	25
			152	131	146

YUB-YECL-9

Reference: Account 87400 – Underground Line Maintenance, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 87400 – Underground Line Maintenance

Request:

(a) Please describe in further detail the specifics of the "increased overall activity" that resulted in $89,000 of costs.

(b) Please explain why YECL included costs for Arctic Winter Games (AWG) support in this account. How does this cost relate to underground line maintenance?

(c) Please describe in more detail the activities related to the $25,000 cost.

Response:

(a) The increase was a result of higher maintenance costs for unscheduled line restoration, underground line patrols, underground line locates, and general underground line maintenance. The overall increase in activity relates to the increased underground infrastructure. See the following table for a breakdown of 2011 and 2012 costs for account 87400:

	2011	2012
Underground Line Maintenance	11,771	29,742
Underground Line Restoration - Unscheduled	1,505	25,327
Follow-Up Maintenance	5,946	13,941
Immediate Maintenance	2,536	8,818
Underground Line Patrols	3,520	21,698
Underground Line Locates	65,404	81,127
Shipyards Substation Work (completed in the timeframe of the Arctic Winter Games)	-	24,618
	90,681	205,272

(b) This work was not completed for Arctic Winter Games support, it was necessary system work completed for Shipyards substation during the timeframe of the Arctic Winter Games.

(c) During regular substation inspection at Shipyard substation, a critical piece of distribution equipment (the 35kV Vista switch cubicle) was found to be faulty. System switching was completed to minimize the area and number of customers impacted if the equipment was to fail. A high voltage switch modular was modified and upgraded to provide contingency if there was a failure. The critical piece of equipment was taken out of service and repaired at a later date.

YUB-YECL-10

Reference: Account 87700 – Transformer Repair and Replacement, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 87700 – Transformer Repair and Replacement

Request:

A cost of $67,000 was incurred in 2012 for repairs required for the Shipyards Park transformer; however, YECL does not explain the cost increases from 2011 to the test period. Please explain why YECL believes these costs will increase to $78,000 in 2013 and continue to increase to $87,000 in 2015.

Response:

In forecasting account 87700 for 2013, 2014 and 2015, additional costs incurred in 2012 for contractors, material and equipment related to the Shipyards Park transformer were excluded.

However, labour costs allocated to 87700 for 2013, 2014 and 2015 were inadvertently based on the 2012 actual allocations, which included a higher than normal amount of labour related to the Shipyards Park transformer. This resulted in a misallocation between this account and other distribution accounts. The total amount of labour allocated to distribution O&M for 2013 to 2015 is correct. Please refer to YUB-YECL-10 Attachment 1 for an overall reconciliation that shows the total distribution labour included in operations and maintenance expenses for the test years is reasonable.

The Yukon Electrical Company Limited
Breakdown of Distribution Expenses - Fringe, Labour, Other

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
Distribution									
87000 - Supervision	Fringe	42	38	47	41	55	55	54	55
	Labour	170	202	156	163	160	172	177	183
	Other	28	30	32	38	48	71	73	76
		240	270	234	242	263	297	305	314
87100 - Brushing	Fringe	15	18	11	8	12	11	11	11
	Labour	63	68	50	36	37	37	38	39
	Other	252	249	295	239	493	355	362	369
		329	335	355	283	543	403	411	420
87200 - Vehicle Depreciation	Other	(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
		(97)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
87300 - Maintenance	Fringe	172	226	308	259	334	313	312	327
	Labour	786	1,035	1,158	1,167	1,127	1,224	1,261	1,335
	Other	377	418	303	383	477	452	461	470
		1,335	1,679	1,769	1,808	1,938	1,989	2,034	2,132
87310 - Service to Outside Parties	Other	70	83	64	90	101	103	105	107
		70	83	64	90	101	103	105	107
87400 - Underground Line Maintenance	Fringe	14	16	13	14	32	33	33	38
	Labour	59	71	55	58	110	105	108	128
	Other	30	32	26	19	63	36	36	37
		103	119	95	91	205	173	177	203
87500 - Meter and Meter Testing	Fringe	12	10	16	9	5	7	7	7
	Labour	47	40	51	37	14	22	22	23
	Other	98	68	27	54	90	60	62	64
		157	118	94	101	108	89	91	94
87700 - Transformer Repair and Replacement	Fringe	1	-	1	1	9	10	11	12
	Labour	5	4	9	10	38	36	37	41
	Other	24	8	26	35	65	32	32	33
		29	12	36	47	112	78	81	87
87800 - Street Light Maintenance	Fringe	13	15	15	13	20	22	22	25
	Labour	54	67	60	55	71	76	78	87
	Other	101	82	92	92	90	95	97	99
		168	164	167	160	181	193	197	210
Total Distibution		**2,336**	**2,638**	**2,662**	**2,659**	**3,281**	**3,141**	**3,215**	**3,376**
Total Distribution Labour		**1,184**	**1,488**	**1,539**	**1,526**	**1,556**	**1,670**	**1,722**	**1,837**

Proof:	**2013**	**2014**	**2015**
Prior Year Distribution Labour	1,556	1,670	1,722
3.5% Inflation	54	58	60
Distribution Costs for 2013 Addition of PLT Service Apprentice Position	57	-	-
Distribution Costs for 2015 Addition of PLT Service Apprentice Position	-	-	61
Other	3	(7)	(7)
Expected 2013 Distribution Labour	1,670	1,722	1,837
Forecast 2013 Distribution Labour	1,670	1,722	1,837
Difference	(0)	(0)	(0)

YUB-YECL-11

Reference: Account 70200 – General Public Information, YECL Application, Schedule 5.1, YECL Application Schedule 5.2

The Board requires more information regarding the cost increases in Account 70200 – General Public Information

Request:

(a) Please confirm that if the Senior Corporate Communication Advisor joined YECL in mid-2011. If yes, should the full cost of this 0.6 FTE already be reflected in 2012? If confirmed, please explain the increase in Account 70200 from 2012 to 2013.

(b) Please explain whether any of the costs forecasted for the test period would be for marketing or advertising purposes.

Response:

(a) Confirmed. The full costs were reflected in 2012. However, there was an allocation change in 2013 to charge the position all to account 70200. In 2012, there was a $9,000 allocation to account 72100. Thus, for 2013 the cost increase reflects labour inflation of 3.5% plus this allocation increase of $9,000.

(b) The forecast costs include print, web and radio communications to the pubic regarding topics related to safety, outages, electricity conservation and customer billing. There are no costs forecasted for marketing purposes.

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUB-YECL-12

Reference: Account 72100 – Administrative, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 72100 – Administrative

Request:

On line 184 and 185 on page 4 of 5 of Schedule 5.2, YECL submitted that it paid higher Head Office Cost of $31,000. How much did YECL previously pay for the head office space before the increase?

Response:

The Head Office Costs referred to on page 4 of 5 on Schedule 5.2 are the various administrative services provided by ATCO Electric and detailed on lines 11 through 16 of Schedule 5.3. These costs do not relate to head office space. The total Head Office Costs increased from $277,000 in 2010 to $309,000 in 2011.

YUB-YECL-13

Reference: Account 72200 – Administration Corporate, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 72200 – Administration Corporate

Request:

(a) Costs in this account increased by $22,000 in 2012 over 2011 due to higher banking fees. Explain the additional $42,000 forecast increase in 2013 over 2012 (i.e. $71,000 plus $22,000 is only $93,000 and not $135,000 leaving $42,000 unaccounted for).

(b) Are the banking fees a direct cost or an allocated cost?

Response:

(a) The additional $42,000 is for forecast bank fee increases in 2013 mainly as a result of increased customer credit card usage. There has been significant growth in the number of customers using credit cards to pay their bills each year from 2009 to 2012, and Yukon Electrical expects this trend to continue in 2013.

Please see the table below for more detail on account 72200:

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	Forecast 2015
Bank Charges	29	42	71	93	135	137	140
Regulatory Expenses	120	142	-	103	-	-	-
	149	184	71	196	135	137	140

(b) Banking fees are a direct cost.

YUB-YECL-14

Reference: Account 72600-Training and Safety, YECL Application, Schedule 5.1, YECL Application, Schedule 5.2

The Board requires more information regarding the cost increases in Account 72600 – Training and Safety

Request:

(a) Costs in this account increased by $69,000 (or 18%) in 2012 due to required safety programs for staff. Please describe this safety program and the components. How many staff members were trained?

(b) Please explain why this cost increase will continue throughout the test period. Does YECL plan to provide this safety program every year going forward?

(c) Please explain why this cost increase did not occur in 2010 or 2011. Was this program not required in 2010 or 2011? What changed in 2012?

Response:

(a) The increase in costs in 2012 was attributable to two training courses for Yukon Electrical's high risk frontline technical employees. A total of 42 employees attended Equipotential Bonding and Grounding as well as Fall Arrest and Pole Top Rescue training.

(b) While not directly related to a similar ongoing level of Equipotential Bonding and Grounding training, the overall level of training will continue throughout the test period due to a number of new initiatives including increased emphasis on driver training as well as project management.

Further to the above, Yukon Electrical has forecast costs throughout the test years based on ongoing training and courses that are required for all employees. Yukon Electrical continues to focus on reducing incidents by ensuring an industry leading safety culture throughout the organization. Ongoing safety training given to the majority of employees includes Zero Incident Culture training, Safety Leadership, First Aid, and WHMIS. Various technical training courses such as Confined Space Entry, Revenue Metering and Advanced Chainsaw are

for Field Service Representatives, Powerline Technicians and Technologists are also provided. Technical courses have certification for 2 or 3 years before recertification training is needed. Technical training costs for apprentices are increasing as Yukon Electrical adds a Power-line Apprentice. As noted above, Yukon Electrical will be providing additional training associated with driver assessments and PACE defensive driving courses for all employees. This is a focused effort and commitment to reduce Yukon Electrical's vehicle incidents. In addition to the increased driver training, Yukon Electrical will also be providing additional Project Management training for staff that will contribute to the success of Yukon Electrical's capital program.

(c) The training programs discussed in (a) were not delivered in 2010 and 2011. They were completed in 2012 due to new work practices and new equipment utilized in the field for these tasks. The high risk frontline technical employees needed to be trained to use the new equipment as designed.

YUB-YECL-15

Reference: Account 72700 – Relocation, YECL Application Schedule 5.1, YECL Application Schedule 5.2

The Board requires more information regarding the cost increases in Account 72700 – Relocation

Request:

(a) Please explain the average cost of relocating an employee or how YECL forecasts how much it will cost to relocate an employee.

(b) Please provide the number of employees YECL forecasts relocating in the test period and how YECL came up with this number.

(c) Please explain whether the costs stem from employees relocating to other ATCO opportunities at the request of ATCO.

Response:

(a) The average cost over the last three years to relocate an employee is $48,600 as shown below:

	2010	2011	2012	Total	Average
Costs - Schedule 5.1, line 44 ($000s)	213	207	66	486	162
Number of relocations	4	4	2	10	3.3
Cost per relocation ($000s)	53	52	33	49	

This includes costs such as house hunting trips, real estate fees on former residence, and moving household goods up to the Yukon.

(b) The forecast number of employee relocations for the test period is 10 (3.3 per year) based on the previous three years, as shown in the table in part (a).

(c) No. Yukon Electrical only pays the moving costs of employees coming to the Yukon.

YUB-YECL-16

Reference: Historical forecast and actuals, YECL Application, Schedule 5.1

The Board requires historical information

Request:

Please update Schedule 5.1 with forecasted, approved, and actual amounts for 2008 and 2009.

Response:

Please refer to YUB-YECL-16 Attachment 1.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Operations and Maintenance Expenses
($000s)

Line No.	Description	Filed 2008	Approved 2008	Actual 2008	Filed 2009	Approved 2009	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015
1	**Production**												
2	62600 - Hydro Generation	96	93	92	129	120	121	111	108	154	320	419	454
3	64000 - Supervision and Engineering Diesel	58	58	59	64	64	60	62	63	69	65	67	69
4	64600 - Diesel Generation	394	397	358	423	422	424	487	601	457	519	704	715
5	82600 - Hydro Maintenance	31	31	49	33	33	33	19	63	105	48	49	51
6	84600 - Diesel Maintenance	1,016	1,018	1,038	951	944	1,010	913	1,013	1,193	1,216	1,238	1,261
7		1,594	1,596	1,596	1,600	1,583	1,647	1,593	1,849	1,978	2,169	2,477	2,550
8	**Distribution**												
9	87000 - Supervision	229	230	240	250	248	270	234	242	263	297	305	314
10	87100 - Brushing	341	339	329	359	354	335	355	283	543	403	411	420
11	87200 - Vehicle Depreciation	(100)	(100)	(97)	(105)	(105)	(142)	(152)	(162)	(170)	(184)	(187)	(191)
12	87300 - Maintenance	1,386	1,345	1,335	1,514	1,391	1,679	1,769	1,808	1,938	1,989	2,034	2,132
13	87310 - Service to Outside Parties	106	106	70	112	112	83	64	90	101	103	105	107
14	87400 - Underground Line Maintenance	122	117	103	131	119	119	95	91	205	173	177	203
15	87500 - Meter and Meter Testing	115	108	157	75	66	118	94	101	108	89	91	94
16	87700 - Transformer Repair and Replacement	28	28	29	30	29	12	36	47	112	78	81	87
17	87800 - Street Light Maintenance	226	221	168	241	227	164	167	160	181	193	197	210
18		2,453	2,394	2,336	2,606	2,440	2,638	2,662	2,659	3,281	3,141	3,215	3,376
19	**General**												
20	88400 - Communication	13	13	8	14	14	18	10	10	15	13	13	13
21	88800 - Maintenance Company-Owned Houses	33	32	32	34	34	11	18	16	16	17	17	18
22	88900 - Maintenance Warehouse and Office	118	118	108	125	123	113	122	115	147	129	132	135
23		164	163	148	173	171	142	150	141	178	159	162	165
24	**Public Information**												
25	70100 - Public Information Administration	100	100	88	106	104	73	45	35	28	27	28	28
26	70200 - General Public Information	28	28	17	30	29	50	58	76	109	124	127	130
27		128	128	105	135	133	122	104	111	137	151	155	159
28	**Customer Accounting**												
29	71000 - Supervision	35	36	30	49	49	53	41	34	52	54	55	56
30	71100 - Customer Applications and Service Orders	407	394	356	450	412	447	410	410	444	478	510	543
31	71200 - Meter Reading	436	434	530	471	455	543	532	462	484	563	576	504
32	71300 - Customer Billing and Accounting	572	553	564	646	605	702	696	703	695	749	765	789
33	71400 - Revenue Collections	162	164	209	258	258	176	165	168	182	228	233	239
34	71500 - Collection of Delinquent Accounts	142	140	131	158	151	98	119	110	123	140	143	147
35	71800 - Provision for Uncollectible Accounts	36	36	36	36	36	34	43	36	36	36	36	36
36		1,791	1,756	1,857	2,067	1,966	2,054	2,006	1,922	2,016	2,248	2,318	2,316
37	**Administration and General**												
38	72100 - Administrative	1,331	1,318	1,515	1,399	1,228	1,505	1,645	1,792	2,028	2,306	2,448	2,445
39	72200 - Administrative Corporate	30	30	27	32	32	149	184	71	196	135	137	140
40	72300 - Insurance	231	231	207	244	244	228	215	244	245	262	202	138
41	72400 - Injuries & Damages	86	86	75	86	86	97	86	86	86	124	124	125
42	72500 - Employee Expenses	222	219	231	312	302	234	253	254	248	278	283	290
43	72600 - Training and Safety	449	444	312	484	464	406	404	387	456	469	479	494
44	72700 - Relocation	182	182	109	77	77	52	213	207	66	160	163	170
45	72800 - Miscellaneous General	2	2	5	3	3	0	-	-	0	0	0	0
46	72900 - Audit/Legal Fees & Special Studies	95	95	71	100	99	200	110	76	143	133	156	138
47		2,628	2,607	2,551	2,736	2,534	2,870	3,110	3,117	3,468	3,866	3,992	3,940
48													
49	**Total Operations and Maintenance Expenses**	8,758	8,644	8,593	9,317	8,826	9,474	9,625	9,799	11,059	11,735	12,319	12,507

YUB-YECL-17

Reference: Inflation forecasts and key assumptions table, YECL Application, pages 1-6 to 1-7

For the 2013 and 2014 test periods, in-scope (subject to a collective agreement) and out-of-scope (not subject to a collective agreement) labour has been escalated by 3.5% and 3.5% respectively. This escalation is based on Yukon Electrical's existing collective agreement that expires on December 31, 2014. For the 2015 test period, in-scope and out-of-scope labour is escalated by 3.5%. This escalation rate reflects Yukon Electrical's forecast of the increase required.

The Board wants to better understand YECL's labour inflation forecast and the methodology YECL used to come up with it

Request:

(a) For the 2013 and 2014 test years the labour inflation rate is subject to a collective agreement that expires on December 31, 2014. Please explain why YECL expects labour inflation to continue to grow at 3.5% in 2015. Please provide any materials/research to support this forecast.

(b) Please provide the date on which YECL negotiated the noted collective agreement and the period to which it applies.

(c) Please provide the inflation forecast for the Yukon (and any other applicable jurisdictions) for the period being negotiated that were available at the time of these negotiations and describe the manner in which YECL and the other negotiating parties arrived at a 3.5% labour inflation rate.

(d) Please explain whether 3.5% is still the most accurate forecast of labour inflation for 2013, 2014, and 2015 given the current economic environment and rates. If not, please provide an updated forecast for 2013, 2014 and 2015.

(e) Would labour inflation be less than what is based on the collective agreement if turnover from more senior to more junior employees is factored in? Please comment.

(f) Please provide statistics on employee turnover for the period from 2008 to 2012.

Response:

(a) A review of collective agreements for other utilities that had already negotiated collective agreements through 2015 was carried out to assess the increases negotiated for 2015. This research provided the following results:

Company	2015 Increase
AltaLink	4.0%
Capital Power	3.5%
EPCOR	3.5%
TransAlta	3.0%

Of the limited amount of data available forward to 2015, these indicators play a role in one of the market areas that Yukon Electrical competes with for skilled labour. Based on these comparatives, Yukon Electrical chose to use 3.5% as its forecast for labour inflation for 2015.

(b) Yukon Electrical negotiated the collective agreement in September of 2012 for the term of January 1, 2013 to December 31, 2014.

(c) Yukon Electrical, with support from the ATCO Electric Human Resources group, establishes an overall compensation strategy based on a combination of factors including internal expertise and experience along with consideration and analysis of a variety of available external market compensation reports. External market data is obtained through various compensation survey organizations, government agencies, professional organizations and applied research organizations, and is analyzed and validated by ATCO Electric's compensation specialists and skilled Human Resource professionals. Some of the data sources referenced by Yukon Electrical in determining the labour inflation rate are as follows:

Conference Board of Canada's Economic Forecast

The Conference Board of Canada's Economic Forecast – Summer 2012 indicates that:

> Labour markets will continue to grow at a good pace as 55,270 jobs are added to the economy (representing growth of 2.6%) in 2013. The unemployment rate will benefit and decline further – to an average of 4.5% in 2013. Tight labour markets will lead to strong wage growth of 3.9 percent in 2012 and 3.4 percent in 2013.

Province of Alberta

The Province of Alberta's Occupational Demand and Supply Outlook 2011-2012 indicates that:

> Over the next ten years, Alberta's labour market is projected to grow by approximately 607,000 workers at an annual average rate of 2.4%. A net increase of 492,000 workers is expected to join the labour force, as occupational supply increases at an annual rate of 1.9%. For the coming decade, Alberta could experience a labour shortage of approximately 114,000 workers.

Conference Board of Canada

The Consumer Price Index (CPI) measures changes in prices, or what is usually referred to as inflation.

Information released July 22, 2011 by *Statistics Canada* indicates that the Yellowknife All-Items Consumer Price Index rose 2.7% from June 2010. By comparison, the annual price increase was 3.1% for Canada, and 3.1% for Whitehorse.

On a year-over-year basis, prices increased in Yellowknife for all major components with the exception of recreation, education and reading.

Comparing June 2011 to June 2010, prices increased by 3.0% in Whitehorse.

Key Economic Indicators

Average Weekly Wage Increase (all employees)

% Change		2009	2010	2011	2012	2013	2014
Alberta		1.7	5.2	3.0	3.2	3.7	3.5
Canada		1.6	1.9	2.9	3.0	3.1	3.1

Source: Conference Board of Canada

GDP/CPI - Alberta

% Change		2011	2012	2013	2014
GDP		3.1	4.0	3.9	4.1
CPI		2.0	2.1	1.9	2.1

Source: Conference Board of Canada

Yukon Electrical and its affiliate companies, Northland Utilities (Yellowknife) and Northland Utilities (NWT), use Statistics Canada, the Yukon Bureau of Statistics, the NWT Bureau of Statistics, and the Canadian Mortgage and Housing Corporation (CMHC) as research sources.

Northern Consumer Price Index (CPI) – Monthly

CPI, All Items (2002 = 100)			
	June 2011	**June 2010**	**Annual Rate of Inflation (July 2010 – June 2011)**
Yellowknife	121.6	118.4	2.2%
Whitehorse	118.6	115.1	2.0%
Canada	119.8	116.2	2.5%

Yukon Electrical participates in analysis surveys that provide information of various indices and cost comparatives including labour indices. The participant companies are major northern employers including the privately owner power

companies and Crown corporation power companies, cities, communications companies and governments. The specific results of these surveys are kept confidential and allow the participants to review their relative competitiveness in the market.

External company agreement settlements in the north ranged from 2.25-2.5% increases in 2012 and 2.25-2.75% for 2013 for those where information was available. A few of the companies were in the process of negotiations or in the ratification process and were unable to confirm increase amounts at the time. Those collective agreements anticipated longer term contracts and lower increases for the first few years progressing to larger increase amounts closer to the end of the contract term.

The Alberta market was strong with external company increases ranging from 2-4%, with a majority arriving at 3% or above for 2012. For those where negotiated settlements were available for 2013, increases ranged from 3-4%. Yukon Electrical looked at a rate of 3.5% as being competitive with respect to that market data.

Competing markets for labour such as Alberta have two large transmission projects underway. Both ATCO Electric and AltaLink have a requirement for stable, specialized labour to support these large projects and this is proving to be challenging for them due to a shortage of local labour.

Yukon Electrical also looks at alignment with other internal collective agreements for it's affiliated northern companies Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

Resources can be transferred between Northland Utilities (NWT) Limited, Northland Utilities (Yellowknife) Limited, ATCO Electric and Yukon Electrical, therefore alignment among these operations is important. In addition, the Alberta market is an important feeder pool for resources in ATCO's northern utility companies.

Northland Utilities (Yellowknife) Limited reached a Collective Agreement for a three year period spanning 2012-2014 with increases at 3.5% each year. Northland Utilities (NWT) Limited reached a Collective agreement for a two year period of 2012 and 2013 with increases of 3.5% for both years.

Yukon Electrical's Collective Agreement was negotiated shortly after those two other agreements.

(d) Yukon Electrical considers the forecast labour inflation rate is appropriate for the test period. A Collective Agreement is now in place for the 2013 and 2014 periods that includes a labour inflation rate of 3.5% in both years. Based on the information outlined in response to information request YUB-YECL-17(a), the forecast for 2015 of 3.5% is also considered an appropriate forecast.

(e) No. The same labour inflation rate is applied to all employees regardless of employee seniority.

(f) Please refer to the following list for a summary of employee turnover during the period from 2008 through 2012:

(i) 2008 – 8 employees came & 3 left

(ii) 2009 – 2 employees came & 3 left

(iii) 2010 – 6 employees came & 6 left

(iv) 2011 – 6 employees came & 1 left

(v) 2012 – 5 employees came & 5 left

Some of the positions were filled by transfers from other ATCO affiliates and the remaining from the local labour market. Yukon Electrical has the ability to recruit and transfer technical-based positions from ATCO Electric. Entry level and non-technical positions are typically recruited from the local labour market.

YUB-YECL-18

Reference: Inflation forecasts and key assumptions table, YECL Application, page 1-7

For non-labour costs, an inflation rate of 1.9% has been applied for 2013 based on 50% of forecast Yukon inflation. For 2014 and 2015, no forecast of Yukon inflation was available so inflation rates of 2.0% and 2.1%, respectively, were applied based on 50% of forecast Alberta inflation and 50% of forecast British Columbia inflation.

The Board wants better understand YECL's non-labour inflation forecast and the methodology YECL used to come up with it

Request:

(a) Please provide the raw data that YECL used to determine the non-labour inflation rates used in this application.

(b) Please explain why YECL used a methodology that weights half of the non-labour inflation rate on Alberta inflation.

(c) Please explain why British Columbia inflation is the best proxy for Yukon inflation. Are there no forecasts for any other jurisdictions that are more representative of economic activity in the Yukon than British Columbia? Does YECL have historical evidence that supports using the British Columbia inflation rate?

Response:

(a) Please refer to YUB-YECL-18(a) Attachment 1.

(b) Yukon Electrical is using this methodology because it was the methodology directed to be used by the Board in Board Order 2009-2.

Use of Alberta inflation is reasonable as Yukon Electrical purchases a significant amount of goods and services from Alberta:

- Yukon Electrical's parent company ATCO Electric operates in Alberta and services received by Yukon Electrical by its parent company are therefore Alberta based;

- Yukon Electrical purchases many of its specialty line materials from Alberta; and

- Transportation services typically come from or through Alberta.

(c) Yukon Electrical was directed in Board Order 2009-2 to tie its non-labour inflation rate to two jurisdictions using a 50/50 weighting. As no forecast was available for the Yukon for 2014 or 2015, British Columbia was chosen as it was the closest jurisdiction to the Yukon. Other than British Columbia being a neighbouring jurisdiction to the Yukon with goods and services flowing up into Yukon, Yukon Electrical does not have historical evidence that supports the use the British Columbia rate.

The Yukon Electrical Company Limited
Forecast of Other Inflation 2013-2015

	2013 Forecast	2014 Forecast	2015 Forecast
Alberta CPI			
Bank of Montreal (Mar 1/13)	1.3	2.0	
CIBC World Markets (Jan 31/13)	1.1	2.4	
Conference Board of Canada (Feb 22, 2013)	1.8	2.2	
Global Insight (Feb 13/13)	1.9	2.1	2.2
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	2.4	2.4	
Alta Gov't Budget 2013 (Mar 8, 2013)	1.8	1.8	1.8
Average	**1.7**	**2.1**	**2.0**
Yukon CPI			
Yukon Gov't (Yukon Econ Development, Feb 5, 2013)	**2.0**		
British Columbia CPI			
Bank of Montreal (Mar 1/13)	1.1		
CIBC World Markets (Jan 31/13)	1.7		
Conference Board of Canada (Feb 22, 2013)	0.6	1.9	2.2
Global Insight (Feb 13/13)	1.0	1.9	2.0
RBC Financial Group (Dec /12)			
Scotiabank (Feb 28/13)			
TD Bank (Dec 19/12)	0.6	1.9	2.2
BC Gov't Budget 2012 (Feb 19, 2013)	1.5	2	2.1
Average	**1.1**	**1.9**	**2.1**
Yukon Electrical Other Inflation Forecast	**1.9**	**2.0**	**2.1**

YUB-YECL-19

Reference: Inflation forecasts, YECL Application, page 1-7

A vacancy rate of 3.4% (approximately 2 FTEs) has been applied to all labour expenses for the 2013-2015 test periods. This is based on a five-year historical average which Yukon Electrical believes to be reasonable and is consistent with the methodology approved in Board Order 2009-2.

The Board seeks clarification regarding YECL's vacancy rate calculation.

Request:

(a) Please provide the raw data that YECL used to determine the vacancy rate.

(b) Please provide the calculations/steps YECL used to come up with the 3.4% vacancy rate.

Response:

(a) Please refer to YUB-YECL-19(a) Attachment 1.

(b) Yukon Electrical used the actual data from the previous 5 years of FTEs to determine a forecast vacancy rate. Please refer to YUB-YECL-19(a) Attachment 1 for the calculation used to come up with the 3.4% vacancy rate.

The Yukon Electrical Company Limited
2013-2015 General Rate Application
Calculation of Vacancy Rate

	Full-time Equivalents				
	Actual	**Forecast**	**+/-**	**Vacancies**	**%**
2008	52.85	54.76	(1.91)	1.91	3.5%
2009	55.51	55.76	(0.25)	0.25	0.4%
2010	54.64	55.43	(0.79)	0.79	1.4%
2011	54.47	57.08	(2.61)	2.61	4.6%
2012	56.36	60.52	(4.16)	4.16	6.9%
				1.94	3.4%

YUB-YECL-20

Reference: Added positions, YECL Application, pages 1-8 to 1-13

Request:

(a) For each of the proposed positions to be added, please indicate which ones will be located in Yukon.

(b) For the senior corporate communications advisor, what is the impact on service quality if the position is not approved by the Board? If there is an effect on service quality, please state the service quality measure and provide an estimate of the impact.

(c) For the environmental technician position, please cite the specific increased regulatory standards, and mandated ongoing ecological and biological studies, and each project requiring an environmental permit.

Response:

(a) Of the 16 positions to be added, 14 positions will be located in the Yukon. The Corporate Accountant (1.0 FTE) and Manager, Financial Reporting and Accounting, North 60 (0.5 FTE) are based in Edmonton.

(b) The Senior Corporate Communications Advisor is tasked to provide timely information and communication to the public regarding safety, outages, electricity conservation and customer billing. Additionally, this position provides internal communication to employees regarding updates and changes within Yukon Electrical. All of these functions are vital to ensure customers and staff have information and access to resources required to understand the services Yukon Electrical provides. This position is also vital in situations when critical public safety situations arise. During these situations, this position provides information and communication to and from the public and acts as a direct link to customers and stakeholders during situations such as public emergencies or unplanned outages.

(c) The new long term licence for the operation of the Fish Lake hydro system includes a number of conditions that impose environmental management and monitoring activities over the course of the licence. Also, the modification of

project infrastructure in the initial years of the licence requires a number of secondary environmental permits to support those operations.

In terms of increased regulatory standards, Yukon Electrical is now required to submit an environmental management and safety plan for the use of heavy equipment adjacent to or in close proximity to water courses and water bodies. This plan will need to be developed for various recurring maintenance activities as well as for the numerous infrastructure upgrades planned for the test period.

Monitoring of nesting shore birds will require coordination with Federal and Territorial environmental managers, all of which Yukon Electrical. Fisheries monitoring activities will require the submission of plans and obtaining secondary permits for sampling fish species. Salvage of stranded fish will require obtaining and reporting upon salvage permits. All of which were not part of the previous long term Water Use Licence.

Construction activities associated with the Fish Lake dyke, the Ditch #3 diversion, and the Ditch #3 drop box will involve development of submissions to the Department of Fisheries and Oceans to obtain and report upon secondary permits such as letters of advice. Plans for use of quarry sources, for traffic restrictions, and for construction waste disposal will also be required from various territorial agencies.

The Environmental Technician will also be the lead for the various permits that Yukon Electrical requires, including air emissions for all 11 Yukon Electrical power plants, special waste storage, Transportation Dangerous Goods air and diesel storage tank permits. This includes applying for amendments and renewals, maintaining compliance and reporting to the regulator as required.

YUB-YECL-21

Reference: Organizational Chart, YECL Application, Section 1, Attachment 1

Request:

(a) Please show the equivalent organization chart for YECL for 2009.

(b) The organization chart shows an allocation of 4.17 people from Head Office. How or by what positions was this work done in YECL's 2008-09 GRA? Where were those costs incurred?

(c) On page 2 of Attachment 1, please explain why there is a need for a supervisor for one person.

Response:

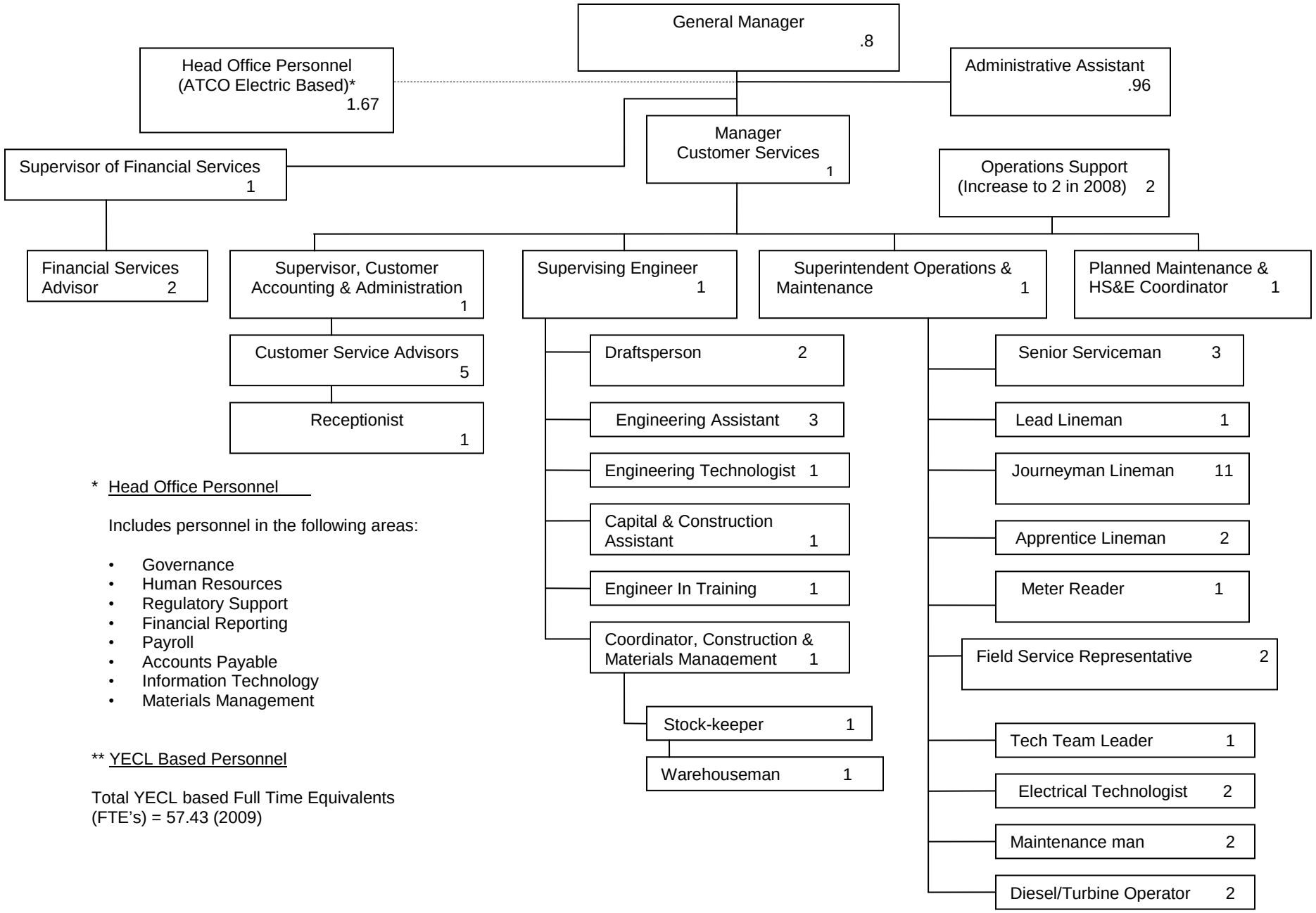
(a) Please refer to YUB-YECL-21(a) Attachment 1.

(b) Both Yukon Electrical's 2008-09 GRA and 2013-15 GRA include an allocation of 1.67 FTEs from Head Office for services related to Governance, Human Resources, Health & Safety, Regulatory Support, Payroll, Accounts Payable, and Materials Management. The allocation has increased to 4.17 since the 2008-09 GRA due to the addition of the Manager, Financial Reporting & Accounting, North of 60 (0.5FTE) and the Corporate Accountant (1.0FTE), which were added in 2012 to address increased workload. As well, the Supervisor, Financial Services (1.0FTE) position was relocated from Whitehorse to Edmonton in late 2011 as a sufficiently experienced and qualified candidate could not be recruited to be based in Whitehorse.

The costs of all of the FTEs allocated from Head Office are included in account 72100 – Administrative on Schedule 5.3 of the Application.

(c) Supervision of a Corporate Accountant is only one of the many duties assigned to the Supervisor, Financial Services. The title of Supervisor was given to the position to be consistent with other positions with a similar level of responsibility in the organization that include both individual contribution as well as supervisory responsibilities.

Organizational Chart
Yukon Electrical Company Limited
2009



* Head Office Personnel

Includes personnel in the following areas:

- Governance
- Human Resources
- Regulatory Support
- Financial Reporting
- Payroll
- Accounts Payable
- Information Technology
- Materials Management

** YECL Based Personnel

Total YECL based Full Time Equivalents (FTE's) = 57.43 (2009)

YUB-YECL-22

Reference: Staff Positions, YECL Application, page 1-7 to page 1-13, YECL Application, Attachment 1, page 1 to page 2

The Board needs more information regarding YECL's staff positions and the operational relationship between YECL and affiliates

Request:

(a) Please confirm that the Supervisor, Financial Services and the Corporate Accountant, who are based out of ATCO Electric's head office, work exclusively on YECL work.

(b) Please confirm that none of the costs associated with the employment of either the Supervisor, Financial Services or the Corporate Accountant are recovered by any other regulated affiliates.

(c) Please confirm that no more than 50% of the cost associated with the employment of the Manager, Financial Reporting and Accounting North of 60, for which YECL is requesting relief, are recovered by any of YECL's other regulated affiliates.

(d) Please explain in further detail the need for the Senior Corporate Communications Advisor. What changed in 2011 that required YECL to establish this position and staff it?

(e) Please provide an estimate of how much of the Senior Corporate Communications Advisor's efforts are spent on advertising campaigns and media relations.

(f) Please explain in further detail the need for the Financial Analyst. What changed in 2011 that necessitated this additional FTE?

(g) Please explain in further detail the need for the Administrative Assistant. What changed in 2011 that necessitated this additional FTE? Who was responsible for YECL's Safe Work Management System before this individual was hired?

(h) Please explain the reasoning for the Engineering Department's reorganization that lead to the creation of the Planning Supervisor position in 2012.

(i) For Meter Readers: Please quantify the increase in customers and further describe "to read meters effectively" (i.e., how was it not effective?).

(j) Once IFRS has been fully implemented, will the Manager, Financial Reporting and Accounting, North of 60 position be removed? If not, why not?

(k) Once IFRS has been fully implemented, will the Corporate Accountant position be removed? If not, why not?

(l) Please explain why YECL has decided to reinstate the Engineer-in-Training position in 2014 after it has been vacant since 2012?

(m) Please explain the need for the Construction Lead position. Before the Construction Lead was hired, who was responsible for overseeing external civil contractors and line crews? What has changed that has necessitated this position?

(n) Please compare the cost of outsourcing the work done by the Engineering Tech 1 Civil and bringing this work in house. If bringing this work in house is costlier than outsourcing to contractors, please provide YECL's justification for doing so. Please describe the offsetting cost savings of bringing this work in house and identify the account in schedule 5.1 that contains the forecast costs for this position.

(o) Please explain in further detail the functions of the Customer Service Advisor. How does this relate to the After-hours – Call Answering service that ATCO Electric provides to YECL? Are these functions redundant?

(p) Please explain the need for the Customer Service Representative. Before the position of Customer Service Representative was established and staffed who was responsible for this position's workload? What has changed that has necessitated this position?

(q) Please explain the need for the Environmental Technician. Before the position of Environmental Technician was established and staffed who was responsible for this position's workload? What has changed that has necessitated this position?

(r) YECL and YEC will jointly be administering the DSM plan and initiatives. Further, YEC is responsible for maintaining the Energy Conservation Office, which was part of its 2012-2013 GRA, and this office has two FTEs. Please explain whether YECL is responsible for any costs originating from the Energy Conservation Office?

(s) If YECL is responsible for any costs originating from the Energy Conservation Office, when were they recovered and is YECL trying to recover any of these costs in its 2013, 2014 or 2015 revenue requirement?

(t) Please confirm that most of the planning and research with regard to the DSM initiative has already been completed by consultants.

(u) Please confirm whether YECL has hired or plans on hiring a DSM Administrator in anticipation of approval of the DSM plan.

(v) Please confirm that the role of the DSM Administrator is to implement the DSM programs. If not, please explain what portion of this FTE is, or will be, dedicated to DSM program implementation. What other responsibilities will this position have?

Response:

(a) Confirmed.

(b) Confirmed.

(c) Confirmed.

(d) Until 2011, the functions of the Senior Corporate Communications Advisor were completed by part-time contractors who could not sufficiently fulfill the requirements or engage fully in the operations of Yukon Electrical. The Senior Corporate Communications Advisor is tasked to provide timely information and communication to the public regarding safety, outages, electricity conservation and customer billing. Additionally, this position provides internal communication to employees regarding updates and changes within Yukon Electrical and engages the service point communities for Yukon Electrical in providing community involvement and communication duties. This position requires

knowledge of the operations of Yukon Electrical to support communication when critical public safety situations arise. This position provides the same services to Yukon Electrical's Northwest Territories Affiliates, Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited. The responsibilities to the two Northland Utilities companies account for 0.4 FTE of this position. This position requires a senior level of experience in corporate communications to deliver the needs of the companies and to deliver the expected level of communication services by the customers of these companies.

(e) The Senior Corporate Communications Advisor's efforts related to media relations and education campaigns including developing and delivering communications to the public through print, web and radio media along with internal communications for employees accounts for approximately 60% of the role.

(f) In 2011, capital spending increased substantially over prior years. The annual forecast of capital spending for each year from 2012-2015 is similarly higher than Yukon Electrical has historically experienced. As a result of the increase in capital spending, an additional financial resource was required to ensure that all projects are properly forecast, monitored and reported.

(g) The Administrative Assistant provides direct administrative and clerical support to the Manager and the Health, Safety and Environment Coordinator. Prior to this position being implemented, administrative and clerical support for these positions was completed by various other office employees in other departments depending on availability and workload. Increasing workload throughout Yukon Electrical resulted in unavailability of support from other departments. The Safe Work Management System did not have a lead person identified prior to the Administrative Assistant, who now ensures that timely and accurate reporting occurs.

(h) The Engineering department was reorganized in 2012 to address the increased capital program and the workload. The Planning Supervisor assumed the responsibility and tasks to ensure Distribution and Generation System Improvements are identified, designed, scheduled and completed. This responsibility was previously assigned to the Supervisor Engineering, Yukon Electrical's only Professional Engineer on staff. The Supervisor Engineer's workload was too great due to major responsibilities including: complete reviews of system impedance data, fault data or other data throughout Yukon Electrical's service area; ensuring power quality, reliability and electrical

utility standards are designed and met; approving all electrical and system designs; as well as being the lead interface for Yukon Electrical with external standards associations and regulators. The tasks of the Supervising Engineer cannot be outsourced.

(i) The communities that are served directly by the additional Meter Reader position are Whitehorse, Marsh Lake, Tagish, and Carcross and surrounding areas, as well as Deep Creek. At the end of 2012, there were 13,688 meters to read every month for these areas. Increases in the number of meters on a number of routes increased the workload to more than the 8 hour work days for the two Meter Reader positions. This resulted in increased error rates and an increasing trend of vehicle incidents that had inattention or working speed identified as root causes. Yukon Electrical acted on this situation to increase the staffing to an appropriate level. Yukon Electrical has also experienced a high turnover rate for these positions due, in part, to the workload and work speed needed to complete the daily reads. As well, additional support to read meters was covered by Field Service Representatives or Powerline Technicians until the third Meter Reader position was created.

(j) This new 0.5 FTE manager position will not be eliminated once the transition to IFRS is completed. Yukon Electrical fully implemented IFRS at the beginning of 2011. The Manager, Financial Reporting and Accounting, North of 60 position was added in mid-2012. This position was added after the transition to IFRS was completed, once the increased volume of on-going work related to IFRS and project support work as well as forecast regulatory activities was known.

With respect to IFRS, Yukon Electrical is now required to maintain two sets of financial records as a result of the various items which require different treatment for regulatory and financial statements purposes. The transition to IFRS was not simply a one-time project that was completed and then workload returned to pre-IFRS levels. Maintaining two sets of records adds complexity and additional reconciliation requirements to reporting for both regulatory and financial statement purposes. As well, there are now two sets of “rules” that accountants at Yukon Electrical have to understand and consider when recording transactions.

With respect to new project support work, this position is responsible to provide complete financial and business support in the development of all new initiatives, including such projects as LNG, net metering and IPP development.

With respect to regulatory, it is clear to Yukon Electrical that interveners are looking for ever increasing levels of granularity when it comes to the testing of past as well as forecast expenditures. This situation is demonstrated in Yukon Electrical's recent GRAs. For its 2008-2009 GRA, Yukon Electrical submitted an Application that was 372 pages long. For its 2013-2015 GRA, Yukon Electrical submitted an Application that was 1,881 pages long. Even without the 1,221 pages of the Application that contained the Yukon Five Year Demand Side Management Plan, the Application included an additional 288 pages of content or 77% more than the previous Application. Despite the additional information provided in its Application, Yukon Electrical still received 60% more Information Requests (1,128 in the current proceeding versus 707 in the 2008-2009 GRA proceeding). Responding to such a high volume of detailed IRs is a significant undertaking that requires the involvement of this position especially when considering Yukon Electrical does not hire outside consultants when completing the vast majority of this work.

In addition to helping lead and complete Yukon Electrical's 2013-2015 GRA, this position is will also be a key resource in providing support for Yukon Electrical's next Phase II Application, currently forecast to occur in 2014, as well as any Yukon Electrical involvement in future Yukon Energy applications that impact Yukon Electrical and its customers such as: General Rate Applications, new Power Purchase Agreements, or other applications such as the recently directed Diesel Contingency Fund and Rate Schedule 42 process. With the exception of legal, Yukon Electrical does not use outside consultants to complete this work.

(k) As discussed in part (j), Yukon Electrical has already completed its transition to IFRS and the increase in workload, including that resulting from maintaining two sets of books, is on-going. The Corporate Accountant, similar to the Manager, Financial Reporting and Accounting, North of 60, was added in 2012 once it was clear that it was not sustainable to have only one position working on all accounting, financial reporting and regulatory issues. Please also refer to part (j) for comments on the ongoing work needed to be completed for regulatory purposes.

(l) The reinstatement of the Engineer-in-Training position is due mainly to transition and succession planning for our Supervisor Engineering position. Yukon Electrical is able to participate in the ATCO Electric Engineering Program that is focused on the training and development of talent that can provide transition and succession planning. As the Supervising Engineer is a critical

position and is the only Professional Engineer at Yukon Electrical, it is reasonable and prudent to ensure proper succession planning is in place.

(m) The need for the Construction Lead position is due to the increased workload of Yukon Electrical's Construction department. The Coordinator, Construction & Materials Management had the responsibilities previous to the Construction Lead position being created. With the increase in capital work, both system improvements and new customer extensions, the Construction Department was reorganized to match the workload. The responsibility of the Construction Supervisor (formerly Coordinator, Construction & Materials Management), as the head of the Construction Department, includes managing, supervising and providing overall direction to construction planning, resource management, project tendering, materials management and contractor management. Increased workload necessitated the split in responsibilities of directing the in field power line and civil contractors and crew management to the Construction Lead. The Construction Supervisor is able to concentrate on the overall management of the Construction Department.

(n) The comparative rate of contractors Yukon Electrical has used for this work is $60 - $225/hour as indicated in WL-YECL-5(j) Attachment 1. The hourly pay scale for Engineering Tech 1 Civil is $35.51 – $50.10/hour for 2013. The creation of the Engineering Tech Civil 1 was to reduce dependency on external contractors and consultants. This position has the lead responsibility for the Fish Lake Hydro system in estimating, designing, scheduling and managing each infrastructure project to completion. The position also ensures all water management reporting, ongoing monitoring and the necessary reports are completed and given to the proper regulatory body.

This position's time is mainly allocated to capital projects. The 33.6% of the costs of this position charged to operations and maintenance expense in Schedule 5.1 are primarily included in 62600 (Hydro Generation), with small percentages allocated to 87300 (Distribution Maintenance), 72500 (Employee Expenses), 72600 (Training and Safety) and 84600 (Diesel Maintenance).

(o) A Customer Service Advisor works directly with our customers on their account inquiries in person or over the phone. The Customer Service Advisors duties include responding to residential and commercial account service inquiries, complaints and service requests including clarification of billing related questions; following up on billing irregularities; receipt of payments; and updating customer accounts. A Customer Service Advisor responds to customer billing

inquiries by accessing the ATCO Customer Information System (CIS). They arrange for the connection and disconnection of electrical service as requested by the customer. They also follow up on all past due accounts as identified by ATCO-CIS.

This position's responsibilities do not include After Hours call answering, so the position is not redundant. The regular office hours are 8:30 AM to 4:30 PM. The Customer Service Advisors only answer customer inquiries and direct emergency calls during regular office hours. The After Hours call answering service is for all hours outside regular office hours and is for emergencies only as no customer account information is available after regular hours.

(p) The Customer Service Representative position is not established and staffed, it is planned for 2014. This position is being created to provide new customers a single point of contact and clear direction on the development of their project to connect to the Distribution System. Regular feedback from new customers indicates confusion and frustration due to required contact with multiple departments during implementation, design, scheduling and construction of their project to connect to the distribution system. The overall goal is to improve customer service to new customer extensions. The position is responsible for creating the project scope and design in consultation with the customer, ensuring field checks; estimates and project scope are consistent with customer expectations. They monitor the overall project execution across multiple departments and follow up with specific departments to meet their commitment on proposed timeline to customer. They also ensure the Terms and Conditions are applied correctly and that any project issues are followed up to closure with customer. Currently, new customers engage directly with multiple employees in different departments to have their project completed.

(q) The Environmental Technician position is not established and staffed, it is planned for 2014. The Environmental Technician position is needed to ensure various new mandated environmental and regulatory reporting activities are completed. This includes monitoring of environmental protection and regulatory compliance for capital projects, diesel emission permits as well as Fish Lake Hydro system ongoing monitoring and studies. The workload for this position is currently spread across a number of employees including project leads and Engineering Assistants. The reporting was inconsistent as a result. There has been increased monitoring, reporting and applications for regular capital and maintenance activities that have to be submitted for YESAB review.

Also, with the renewal of various permits and licences, the environmental reporting requirements continue to increase.

(r) Yukon Electrical is not responsible for any costs related to YEC's Energy Conservation Office.

(s) Yukon Electrical is not responsible for any costs related to YEC's Energy Conservation Office.

(t) Confirmed.

(u) Confirmed. Yukon Electrical has hired a term DSM Coordinator.

(v) Confirmed. The DSM Coordinator position is fully dedicated to the implementation and delivery of DSM programs.

YUB-YECL-23

Reference: Line item – Display Change to YECL Billing Statements, projected expenditure of $260,000, YECL Application, page 9-51

To provide customers with additional electrical consumption information about their own consumption and to provide additional transparency about the electrical rate structure in the Yukon and how customer consumption translates to their actual electrical costs.

Request:

(a) Please explain in further detail the expected benefit that both the company and consumers will receive from changing the display in the electrical billing statements.

(b) Please provide a cost breakdown of the actions and/or processes required to make the billing statement change (e.g. programming, capital acquisitions, graphic design).

Response:

(a) The energy charge for residential and general service customers is based on a block structure in which each energy block is at a progressively higher cost. This rate structure is currently invisible to the customer, other than on the Yukon Electrical website, and is currently displayed as a combined total on the monthly statement. Most customers are unaware of the current rate block structure.

The monthly billing statement is the primary method used to communicate with customers and presents a unique opportunity to provide customers with information specific to their own consumption.

Displaying the block calculations supports public education goals in the proposed DSM programs and can provide additional information to customers considering electricity conservation measures.

Providing the customer with the calculations in each applicable block will provide additional clarity in understanding the financial impact of using more electricity.

(b) The project will consist of the following steps, which include multiple programming changes, Central Processing Unit time, and extensive testing:

- $62,000 - Configure ATCO-CIS (Customer Information System) company parameters for Yukon Electrical to display energy block calculations on the statement. This requires programming changes to core components of the software.

- $79,250 - Configure the ATCO-CIS Statement display process to present the detailed calculation of the consumption used in each charge period on the customer's monthly bill. ATCO-CIS is currently configured to summarize the total of the energy block calculation as a single "energy charge". This requires changes to statement layout and design as additional space will be required for the block display.

- $54,000 - Configure rates for all customer classes to display blocks for the energy component, the programming changes impact twenty different rates.

- $54,750 - Perform user acceptance testing in the test environment before elevation of program changes to the production environment. This process involves testing various charging scenarios for all twenty rates including:

  - Normal billing period
  - Multiple billing periods
  - Multiple service accounts on a single statement
  - Initial bill
  - Final bill
  - Proration of energy block calculations over a rate change

- $10,000 - Elevation of all changes to production environment.

YUB-YECL-24

Reference: Demand-side management as it relates to revenue requirement, YECL Application, Business Case #30, page 1

Yukon Electrical, in partnership with Yukon Energy (YEC), has developed a five-year plan (2013-2018) to implement and measure demand-side management (DSM) programs for the Yukon that is being filed with this Application.

The Board seeks clarification on forecast costs related to DSM planning and implementation.

Request:

(a) Based on the quote above, please confirm that YECL anticipates implementing the DSM programs in 2013.

(b) On page 6 of Business Case #30, YECL submitted that Project Costs were $204,000, $143,000, $135,000, $522,000, $730,000 in 2011, 2012, 2013, 2014 and 2015 respectively. Please provide an update on how much YECL has actually spent on DSM to date since 2010. What were these costs for? Please delineate these costs.

(c) Have any costs related to DSM been expensed or gone into YECL's revenue requirement? If so, which accounts have been affected and by how much?

(d) Please provide the cost/benefit analysis for this business case.

Response:

(a) Yukon Electrical has been working with Yukon Energy collaboratively since 2011 to build a Demand Side Management plan for the Yukon. As part of the initial preparation for potential programs, a Conservation Potential Review (CPR) was completed. From that document, it was determined there was potential for electricity savings from DSM in the Yukon. The next stage involved developing a Program Portfolio, an Implementation Plan and an Evaluation, Measurement and Verification Plan. The utilities are now in the process of preparing for an anticipated public launch of DSM programs in late Q2 of 2014. This preparation

includes preparing internal systems and processes, engaging market actors, developing branding and marketing materials and developing an interactive customer website. This assumption is based on YUB approval of the programs as filed.

(b) Please refer to the *YECL-DSM Costs 2011-2015* spreadsheet, provided as YUB-YECL-24(b) Attachment 1, for details of Yukon Electrical costs related to DSM.

(c) Yes, costs related to DSM have gone into Yukon's Electrical revenue requirement. The DSM costs as outlined in Business Case #30 are included in capital additions for 2011-2015 and are included as additions to rate base beginning in 2013, on the assumption that the forecast costs will be approved as filed.

It is Yukon Electrical's intention to capitalize all costs associated with the DSM program. However, in preparing the responses to Information Requests, it was discovered that some costs had inadvertently been included in both Operations and Maintenance expenses and Capital. These amounts total $88,000 for 2013, $90,000 for 2014 and $92,000 for 2015. This duplication will be rectified by the removal of costs from O&M and this will be corrected and submitted as part of Yukon Electrical's compliance filing.

(d) The Yukon Electrical Business Case #30 is based on the *Yukon Five Year Demand Side Management Plan*. A cost/benefit analysis of the plan was completed and is based on the four standard cost effectiveness tests described in Appendix F of the *Yukon Five Year Demand Side Management Plan* included in the Application. The analysis of the cost/benefit ratios for each program as well as the total plan can be found in Exhibit 4 on page 15 and Exhibit 5 on page 16 of the *Yukon Five Year Demand Side Management Plan* included in the Application.

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2015

Expenditure Type		Amount
DSM ADMINISTRATOR	$	93,000.00
STAFF TRAINING AND DEVELOPMENT		
PROJECTED COSTS FOR STAFF EDUCATION	$	17,000.00
DSM GENERAL SERVICE PROGRAM COSTS		
LIGHTING REDESIGN AND EQUIPMENT INCENTIVE	$	75,000.00
NEW CONSTRUCTION INCENTIVE	$	3,000.00
ENERGY STAR COMPUTER INCENTIVE	$	38,000.00
HIGH EFFICIENCY REFRIGERATION INCENTIVE	$	38,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	120,000.00
PROGRAM MANAGEMENT	$	79,000.00
	$	353,000.00
DSM RESIDENTIAL PROGRAM COSTS		
LED LIGHTING AND AUTOMOTIVE TIMERS	$	38,000.00
LOW COST ENERGY EFFICIENT PRODUCTS	$	78,000.00
CCHP AND GSHP INITIATIVE	$	15,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	65,000.00
PROGRAM MANAGEMENT	$	71,000.00
	$	267,000.00
FORECASTED 2015	$	730,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2014

Expenditure Type		Amount
DSM ADMINISTRATOR	$	93,000.00
STAFF TRAINING AND DEVELOPMENT		
PROJECTED COSTS FOR STAFF EDUCATION	$	17,000.00
DSM GENERAL SERVICE PROGRAM COSTS		
LIGHTING REDESIGN AND EQUIPMENT INCENTIVE	$	26,000.00
NEW CONSTRUCTION INCENTIVE	$	11,000.00
ENERGY STAR COMPUTER INCENTIVE	$	17,000.00
HIGH EFFICIENCY REFRIGERATION INCENTIVE	$	12,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	87,000.00
PROGRAM MANAGEMENT	$	44,000.00
	$	197,000.00
DSM RESIDENTIAL PROGRAM COSTS		
LED LIGHTING AND AUTOMOTIVE TIMERS	$	25,000.00
LOW COST ENERGY EFFICIENT PRODUCTS	$	74,000.00
CCHP AND GSHP INITIATIVE	$	7,000.00
ENGAGEMENT, TRAINING AND COMMUNICATION	$	57,000.00
PROGRAM MANAGEMENT	$	52,000.00
	$	215,000.00
FORECASTED 2014	$	522,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2013

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
ENERGY BLOCK FEASIBILITY	$	20,000.00
STAFF		
DSM ADMINISTRATOR	$	47,400.00
CONSULTATION		
FIRST NATION ENERGY SUMMIT	$	1,400.00
CONSULTANT SERVICES		
ICF MARBEK - PROGRAM IMPEMENTATION / EM&V PLANS	$	30,000.00
LAUNCH CONTRACTOR	$	20,000.00
	$	50,000.00
STAFF TRAINING AND DEVELOPMENT		
STAFF TRAINING AND DEVELOPMENT	$	15,000.00
LED STREET LIGHT JOINT PROJECT		
MATERIALS PURCHASED - LIGHTS	$	1,200.00
FORECASTED 2013	$	135,000.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2012

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
EM&V DATA PREPARATION	$	19,000.00
EDUCATION		
DOLLARS TO SENSE WORKSHOP	$	2,000.00
COMMUNICATION & ENGAGEMENT		
COMMUNICATION SERVICES	$	2,000.00
INCHARGE BRANDING	$	3,800.00
	$	5,800.00
CONSULTANT SERVICES		
PROGRAM DESIGN - ICF MARBEK	$	75,000.00
ONE CHANGE COMMUNITY ENGAGEMENT	$	41,000.00
	$	116,000.00
LED STREET LIGHT JOINT PROJECT		
MATERIALS PURCHASED - LIGHTS	$	2,000.00
TOTAL FOR 2012	$	144,800.00

The Yukon Electrical Company Limited
Breakdown of DSM Costs - 2011

Expenditure Type		Amount
DATA / BILLING SYSTEM IMPROVEMENTS		
ENERGY BLOCK FEASIBILITY	$	42,000.00
DATA REQUEST FOR CPR STUDY	$	3,000.00
	$	45,000.00
EDUCATION		
DOLLARS TO SENSE WORKSHOP	$	5,000.00
STAFF TRAINING AND DEVELOPMENT		
STAFF TRAINING AND DEVELOPMENT	$	4,000.00
CONSULTANT SERVICES		
CPR STUDY - ICF MARBEK	$	87,000.00
ONE CHANGE COMMUNITY ENGAGEMENT	$	63,000.00
	$	150,000.00
TOTAL FOR 2011	$	204,000.00

YUB-YECL-25

Reference: Electricity consumption in the Yukon, Yukon Five Year Demand Side Management Plan, Page 4

The CPR shows that in 2010, Yukon's residential sector consumed about 146,000 MWh of electricity

The Board requires the most up-to-date information available.

Request:

(a) Do YEC and YECL have an update of how much electricity is consumed in the Yukon for both the residential and commercial classes?

(b) Has the DSM program been implemented yet?

(c) To date, what activities have YEC and YECL conducted with regard to implementation of DSM? What has YECL done?

(d) What elasticity studies has YECL undertaken with respect to the demand for electricity? Please provide the results of those studies.

Response:

(a) The most up-to-date sales numbers as provided by each utility are detailed below:

Yukon Energy	2011 Residential – 12,834,145 kWh
	2011 Commercial – 21,537,664 kWh
	2012 Residential – 13,288,643 kWh
	2012 Commercial – 22,445,877 kWh
Yukon Electrical	2011 Residential – 141,696 MWh
	2011 Commercial – 150,591 MWh
	2011 Lights – 4,179 MWh
	2012 Residential – 150,350 MWh
	2012 Commercial – 159,562 MWh
	2012 Lights – 4,331 MWh

(b) No, DSM programs have not been implemented; however activities to prepare for program implementation have been on-going since 2011. As part of initial preparation for potential programs a Conservation Potential Review (CPR) was completed. From that document it was determined there was potential for electricity savings from DSM in the Yukon. The next stage involved developing a Program Portfolio, an Implementation Plan and an Evaluation, Measurement and Verification Plan. The utilities are now in the process of preparing for an anticipated public launch of DSM programs in late Q2 of 2014. This preparation includes preparing internal systems and processes, engaging market actors, developing branding and marketing materials and developing an interactive customer website. This assumption is based on a YUB approval of the programs as currently submitted.

(c) Yukon Energy and Yukon Electrical have cooperatively developed: the Conservation Potential Review for the Yukon; the Program Portfolio; the Program Implementation Plan; and the Evaluation, Measurement and Verification Plan. These plans are the foundation of public programs to be delivered to residential and commercial customers in order to meet the utilities' goal of 8.5 GWh of sustained electricity savings by the end of the five-year program cycle. Yukon Electrical has partnered with Yukon Energy on all of these initiatives.

(d) Yukon Electrical has not performed an analysis of the elasticity of demand for electricity due to the complexity of the study, lack of appropriate data and extensive amount of time it would take to perform such a study. However, based on a survey of studies reported for some jurisdictions in the U.S. by the Electric Power Research Institute titled, "Price Elasticity of Demand for Electricity: A Primer and Synthesis", dated January 2008, the elasticity of demand for general electricity use is estimated in the range of -0.2% to -0.6% in the short-run (1-5 years), and -0.7% to -1.4% in the long-run for residential customers, and between -0.2% to -0.7% in the short-run, and -0.8% to -1.3% in the long-run for commercial customers. Based on these numbers, for example, a 10% increase in the price of electricity of the residential rate class in the short-run would result in, everything else being constant, a 2% to 6% drop in electricity consumption by residential customers. For commercial customers, the same increase in price in the short-run would result in, everything else being constant, a 2% to 7% drop in electricity consumption. It should be noted that these elasticity estimates were all derived for jurisdictions with enabling technologies that provide for some sort of time-variable pricing (dynamic pricing) such as Time of Use, Critical Peak Pricing, or Real Time Pricing. As such, these customers are more aware and capable to react to price changes, if they choose to do so.

YUB-YECL-26

Reference: Public messaging and programing, Yukon Five Year Demand Side Management Plan, Page 8

The working group will jointly agree to develop: a program delivery process, electricity conservation public messaging, youth education programming, stakeholder consultation, evaluation, measurement, and verification of programs.

The Board wants to further understand how YEC and YECL plan on evaluating, measuring, and verifying program effectiveness

Request:

(a) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the electricity conservation public messaging is effective.

(b) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the youth education programming is effective.

(c) Please describe how YEC and YECL plan on evaluating, measuring and verifying whether the stakeholder consultations have been effective.

Response:

(a) The utilities will retain a third-party evaluation, measurement and verification (EM&V) contractor to look over the entire program portfolio and report on its effectiveness to the YUB. The utilities have prepared a set of performance indicators related to conservation public messaging. For example, a number of new market actors being engaged with, number of people attending classroom training, 1-to-10 scale level of satisfaction with the training on average, etc. These examples can be found on pages 32 and 33 of the *DSM Program Evaluation Measurement and Verification Plan*, provided as YUB-YECL-26(a) Attachment 1.

(b) The youth education component of the program is captured in the residential sector engagement, education and communication plan on page 95, section 4.4

of the *Yukon Five Year Demand Side Management Plan* included with the Application. This program is also subject to the EM&V plan.

(c) The utilities do not intend to explicitly ask the independent evaluators to comment on the effectiveness of the stakeholder consultations in a direct manner. It will be left to the independent evaluators to decide if they want to comment on them. As part of the process evaluation, evaluators will be provided with full access to the program documentation including, but not limited to: the Conservation Potential Review report and the market consultation / characterization documentation (reports, interview guides, protocols, consultations notes and so on).

Demand-Side Management (DSM) Program Portfolio for the Yukon

FINAL

Evaluation, Measurement and Verification Plan

Date: May 30, 2013

Submitted to:
Yukon Energy Corporation
Yukon Electrical Company Limited

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1. Introduction

Yukon residents rely on electricity not only to live meaningful, healthy lives but also to support and strengthen the economy. Given the concerns over environmental implications including climate change, and the limited generating capacity in the Yukon, there is growing interest not only in how electricity is generated, transmitted and distributed but also how efficiently it is used at the customer's end. In the Yukon, as well as in a growing number of North American jurisdictions, how electricity is generated and used is being closely analyzed to find innovative ways of meeting individual and corporate energy service needs while minimizing pollution and the creation of greenhouse gases.

In response to these conditions, the Yukon Energy Corporation (YEC), Yukon Electrical Company Limited (YECL) and the Yukon Government collaboratively commissioned a comprehensive study of the opportunities for electricity demand-side management (DSM) within the Yukon. That study, entitled *Conservation and Demand Management Potential for the Yukon 2011*, was completed in January 2012 and revealed a significant cost-effective potential for electricity DSM in the Yukon.

Based on those findings, the YEC and YECL developed a suite of residential and commercial sector program offerings that will enhance the Yukon's electricity DSM program portfolio and provide incremental annual electricity savings of 9.3 GWh/yr by the fifth year of the program. The results of the development work are presented in a report, entitled *Demand-Side Management Program Portfolio for the Yukon* (also known as Program Design Document), which was completed in September 2012.

The final step in the DSM planning process involved the development of a program implementation plan (PIP) suitable for submission to the Yukon Utilities Board, together with an evaluation, monitoring and verification (EM&V) plan.

This report presents the recommended evaluation, measurement and verification (EM&V) plan for the Yukon DSM portfolio; it accompanies the PIP, which has been delivered under separate cover.

1.1 Objectives & Scope

The objectives of this EM&V plan are:

- To define an EM&V framework that will enable the Yukon Utility Board (YUB) to protect the interests of the ratepayers and maximize the value of DSM for all stakeholders, while also being compatible with the size of the Yukon market.
- To document the program's original theory and objectives for the evaluators to establish the basis for measuring success.
- To develop a high-level EM&V methodology and work plan to confirm the funding level, foresee data collection needs, and incorporate EM&V considerations into the regular program operations, accounting and management functions.
- To support the selection of program evaluators by providing a high-level description of the tasks and capabilities required.[1]

There are three audience groups for this report:

- The DSM program administration staff and the utility management committee.
- The Yukon Utility Board (YUB), the interveners, and other stakeholders.
- The selected evaluators.

The approach presented in this report is preliminary, and should be considered as a suite of options which, as a whole, represent EM&V best practice. The final evaluation scope will be determined through the stakeholder engagement process.

1.2 Report Presentation

The remainder of this report is organized and presented in the following sections:

- Section 2 introduces the recommended EM&V framework for electricity DSM in Yukon.
- Section 3 provides an overview of the Yukon DSM and defines a high-level approach, key milestones and deliverables, and a schedule for EM&V activities.
- Section 4 presents the description, program theory, management by objective (MBO) framework and methodological implications for each of the program elements within the DSM portfolio.
- Section 5 presents an approach, guidelines and criteria to select impartial and capable evaluators.

[1] The team developing this EM&V plan was also involved in the development of the program portfolio. Evaluators will be selected outside of the development team to avoid any conflict of interest. After being selected, the impartial evaluators will provide their expert opinion on the methodology and work plan, gather comments from relevant stakeholders, edit and finalize the EM&V plan.

2. EM&V Framework for DSM in Yukon

Section 2 sets out the recommended high-level characteristics of the DSM evaluation framework for the Yukon. The discussion is organized into the following sub sections:

- General approach
- Rationale for DSM evaluation
- Targets and performance indicators
- Level of rigor and funding
- Applicable evaluation best practices
- Roles and responsibilities
- Technical reference manual and deemed savings

2.1 General Approach

A sound evaluation framework should lay the ground for superior energy conservation policy planning and program management to increase the value of DSM for the Yukon ratepayers and society. The key is to balance:

- The Program's need for quick program performance feedback and for flexibility to adapt the DSM portfolio to changing market conditions.
- The expectation of the DSM program participants for excellent customer service from the Utilities which in many cases implies swift processing of a minimal amount of paperwork.
- The need of the regulator to ensure ratepayer monies are being used in an effective and efficient manner to achieve energy impacts.
- The need of the Yukon society for a self-improving DSM program portfolio, which monitors market feedback, and applies educated and evidence-based recommendations to improve the portfolio.

The recommended approach for the Yukon is a two-layer portfolio monitoring approach:

- **Internal Tracking and Performance Reporting:** DSM program administration staff will track a set of indicators as defined below. Indicators are monitored by diligently inputting data into a program tracking system (program database) and periodic reports are generated (quarterly, yearly) that compare actual results against targets. This will enable the program administrator, as applicable, to justify results, suggest corrective measures and update targets for the next period.
- **Third-Party Program Evaluation:** The Utilities will employ third-party evaluators that will carry out a set of verification, research and reporting activities as defined in this report. Third-party program evaluation provides a check and balance that is superimposed on internal tracking and performance reporting. The program evaluators will retrieve the program database and documentation; check that program procedures and eligibility criteria were complied with by the administration staff; retrieve additional market data through consultation, surveys and other research methods; use advanced energy analytics to improve the accuracy and precision of the impact estimates; and provide constructive criticism of the DSM portfolio.

This EM&V plan focuses primarily on the second layer: *third-party program evaluation*. The tracking and performance reporting infrastructure and functions were described extensively in the Program Implementation Plan. This EM&V plan will refer to tracking when tracking data is needed for evaluation purposes.

The EM&V plan was built based on a 5-year DSM portfolio planning and operation cycle; thus with a 5-year impact evaluation reporting cycle. A 3- to 5-year cycle is standard practice in the industry because it maximizes the value of evaluation. A 5-year cycle was preferred as a means of constraining the EM&V costs. This recognizes the relatively small size of the Yukon DSM market and, consequently, the relatively small size of the DSM budget.

2.2 Rationale for DSM Evaluation

Evaluation is meant to improve DSM program performance such that it sustainably obtains incremental electricity and demand savings. The high-level objectives of DSM evaluation are:

- **Establishment of DSM as a credible and reliable resource:** DSM evaluation increases the accuracy and precision of the impact estimates (e.g. avoided kWh and kW) thus making DSM impact claims worthy of being compared with supply-side resources. The power system planners need to trust in DSM if they are to postpone or curtail supply-side investments on the basis of the DSM projections; actually postponing and curtailing these investments is key to realizing a large portion of the societal benefits of DSM.
- **Explanation of the performance of the programs:** Evaluation helps DSM administration staff interpret the tracking data, and explains why certain programs have under-performed or over-performed. Evaluators consult with several market actors to obtain insights on the reactions of the market to the DSM programs and to seek solutions.
- **Recommendations to adapt and improve programs:** Evaluators will use the results of their research and consultation in Yukon, as well as their experience with DSM in other jurisdictions, to make educated recommendations to adapt and improve the DSM portfolio. For example, those recommendations can include the identification of: subtle tune-ups of operating practices; promising new tactics; ineffective tactics; new DSM opportunities: exit strategies for specific program elements; and, changes in the delivery approach.
- **Accountability of the DSM program administrator:** Evaluators will have access to all of the program documentation including the CPR report, the market characterization reports, the PIP, the tracking database, communication materials, meeting minutes, performance reports, budget and planning, etc. They will identify issues, if any, with the approach to planning and taking programs to market, record keeping practices, data quality control procedures, the timeliness of the application processing, performance indicators, mid-course portfolio adjustments, and ultimately the DSM management and administration practices.

2.3 Targets and Performance Indicators

The utilities will aim to achieve total net electricity savings that are equal to or greater than the total amounts presented in the DSM portfolio projections, and at a total cost that is equal to or less than the total amount presented in the DSM budget (see the Program Design document). However, the utilities will have the flexibility to move targets and budgets between the DSM program elements to adapt to changing market conditions and early program results. Quarterly budgets will also be flexible as long as annual budgets are complied with.

The performance of the program will be measured through the following three sets of activities:

- The performance will be periodically monitored by the DSM administration staff by comparing *key performance indicators* (KPIs) with pre-established targets – that will include kW and kWh savings, or *impacts*.
- The KPIs will be validated by the evaluators by conducting a desk review of the program database and the program documentation, additional research activities, and advanced energy analytics.
- The evaluators will also establish and monitor additional indicators (*evaluation indicators*) to verify that the DSM portfolio is being delivered effectively and that it generates sustainable positive changes in the market.

The program activities will be tracked and performance will be reviewed according to the report and planning schedule presented the Program Implementation Plan (See Section 4.4).

Tracking – Key Performance Indicators

The program accounting system and internal tracking systems will report on the KPIs for each of the program elements of the DSM portfolio. The most important KPIs are listed below.

1. Number of transactions and number of business days of average processing time
2. Incentive disbursement cost
3. Program cost and administration cost
4. kWh and kW savings (gross)[2]
5. Number of transactions being verified on site (to be determined with the DSM administration staff at the preparation stage and then validated by the EM&V contractor)
6. Direct-engagement indicators (to be determined with the program staff at the preparation stage)
7. Indirect communications indicators (to be determined with the program staff at the preparation stage)

The targets for KPIs (1) to (5) above were set out in the projection tables presented in the Program Design Document. KPIs (6) to (8) will be established during program set up in collaboration with the core program staff.

In addition to the information required to track the KPIs above, the evaluators will designate a limited number of information items to be collected for EM&V purposes.

[2] The tracking system will report on net impact if a stipulated net-to-gross ratio is used.

All KPIs computed by the DSM accounting system and the tracking system(s) will be verified by evaluators. The evaluators will also validate the approach to on-site verification, and the information items being collected through the applications and forms for verification purposes.

Evaluation – Evaluation Indicators

In addition to the KPIs stated above, evaluation indicators will be established and documented through EM&V to test the effectiveness of the DSM portfolio delivery mechanisms.

Both the KPIs and the evaluation indicators and targets will be laid out in detail in a management-by-objective framework (MBO framework). The suggested MBO Framework is presented in Section 4.

2.4 Level of Rigor and Funding

The value of EM&V can also to be maximized through setting realistic expectations for the precision and accuracy of the impact estimates. The cost of evaluation grows exponentially as the level of rigor is set higher, and since the cost of DSM remains lower than supply-side options it is common to tolerate a wider margin of error.

One common approach is to set the level of EM&V funding and then establish what is achievable in terms of evaluation scope as well as accuracy and precision of expectations. This is the approach used in this EM&V plan.

Most industry standards suggest allocating 3 to 10% of total program funds to EM&V, where the higher end of the range is for (1) newer programs and (2) smaller programs. It is expected that the Utilities' new DSM programs will be small programs relative to most other jurisdictions. Thus, the Utilities expect to invest between 5 and 8% of the DSM budget in EM&V. The current EM&V plan reflects this level of funding.

The accuracy and precision are to be recommended by the evaluation contractors when bidding on the evaluation work. The level of rigor is to be differentiated by program element. The evaluators shall seek to allocate more resources to program elements that have yielded the highest impact (based on KPIs).

2.5 Applicable Evaluation Best Practices

The Utilities intend to follow the general principles of the California Evaluation Framework[3] and the California Evaluation Protocols (a.k.a. Evaluators' Protocols)[4] but at a level of rigor that is consistent with the size of the overall program.

The two reference books noted above are suggested for the Yukon because:

- The North-American DSM evaluation industry is familiar with them. Few evaluation references are more used than these two California documents; they are the result of extensive work by dozens of evaluation professionals to collect and consolidate EM&V methods and options that had been used successfully at the time. The selected evaluators will be at ease.

[3] **CPUC**, *California Evaluation Framework*, TechMarket Works, USA, 2004, [ONLINE] As seen on March 25, 2013, URL: http://www.calmac.org/publications/California_Evaluation_Framework_June_2004.pdf
[4] **CPUC**, *California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals*, USA, 2006, [ONLINE] As seen on March 25, 2013, URL: http://www.calmac.org/events/EvaluatorsProtocols_Final_AdoptedviaRuling_06-19-2006.pdf

- They are comprehensive reference books with a wealth of methodological options from the most basic to the highest level of rigor, for many types of evaluation, and for a vast array of program designs. They are versatile and flexible.
- Both handbooks refer to the International Performance Measurement and Verification Protocol (IPMVP)[5] for larger projects that justify investing in actual field measurements, as required.
- In addition to project-level M&V, these handbooks accommodate one or many approaches to carrying out impact estimates: billing analysis, sampling and the use of statistics, deemed savings, and advanced engineering methods.

Most of the EM&V methods that will be put forward will need to be defined and/or positioned relative to the recommended approaches suggested in the Evaluation Framework and the Evaluators' Protocols.

Evaluators will be expected to make an educated use of the California handbooks. They will be able to suggest alternate approaches and methodologies, as appropriate.

2.6 Roles and Responsibilities

The Utilities intend to employ one third-party evaluation contractor for both the General Service Program and the Residential Program.[6]

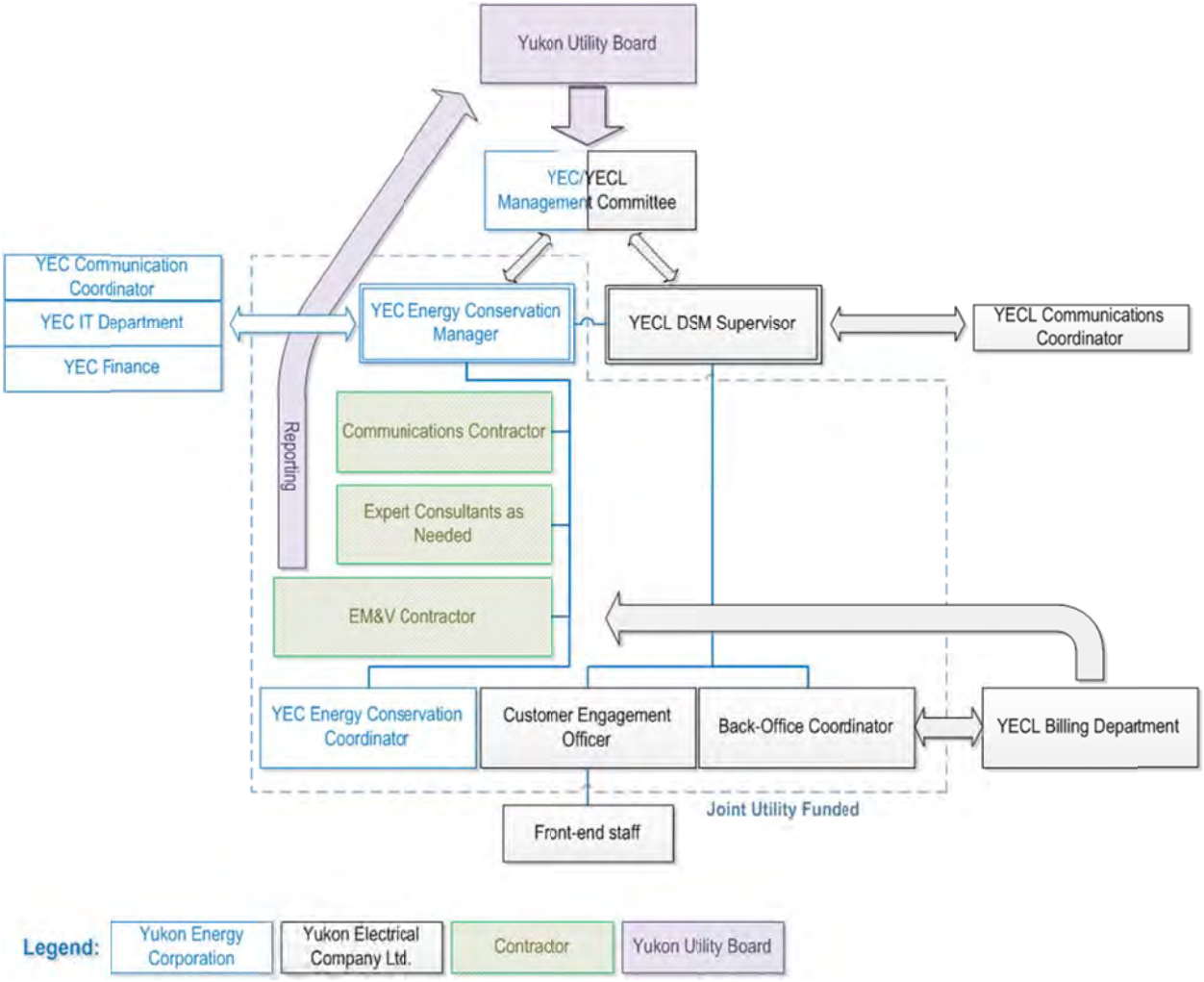
The value of EM&V will be maximized through a practical division of responsibilities between DSM administration staff and the EM&V contractor. For example, certain measurement or site-visit activities can be carried out and documented by the administration staff as part of regular tracking at a much lower cost than if they were to be performed by the EM&V contractor. In this case, the logs and documentation would be reviewed by the contractor.

[5] **EVO**, *International Performance Measurement and Verification Protocol, Volume I, 2012*, USA 2012, [ONLINE] As seen on March 25, 2013, URL: http://www.evo-world.org

[6] It is desirable to retain one EM&V contractor for both the General Service Program and the Residential Program because the total budget envelope for evaluation is relatively small and bundling will allow for economies of scale. In addition, DSM will benefit from the EM&V contractor having flexibility to assign resources among the program elements based on actual impact and/or expenses to date in order to maximize the value of evaluation.

Exhibit 1 outlines the anticipated organization of key roles once the program is fully launched and is in full operation. An explanatory note is presented in tabular format following the chart that presents the tracking and EM&V responsibilities for the key players involved in the operation of the DSM portfolio, and how they relate to the Management Committee and the YUB.

Exhibit 1: Organization Chart during Full Program Operation



Position	Payroll	Role/Responsibility with Regard to EM&V
YEC Energy Conservation Manager	YEC	• Jointly accountable with the YECL DSM Supervisor for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YECL DSM Supervisor. • Jointly develop the budget and the plan for next year and defend it in front of the YEC/YECL Management Committee with YECL DSM Supervisor. • Develop the initial EM&V plan – to be finalized through consultation with the EM&V Contractor, YECL DSM Supervisor, the YEC/YECL Management Committee, and the YUB.

Position	Payroll	Role/Responsibility with Regard to EM&V
		• Prepare reports and documents to be filed with the YUB under the supervision of YEC/YECL Management Committee (most likely made of extracts from the aforementioned reports, budgets and plans). • Procurement of the services of the EM&V contractors, and expert consultants when needed. • Coordination between the positions or resources shown in Exhibit 1. • Update the detailed work plan on a sliding quarterly basis. • Quality control/quality assurance of the EM&V Contractors' deliverables. • Monitor the customer engagement KPIs • Work jointly with the YECL DSM Supervisor to update and approve of the engagement plan updates by the YECL Customer Engagement Officer.
YEC/YECL Management Committee	YEC or YECL	• Review and comment on the reports, budgets and plans drafted by the YEC Energy Conservation Manager and the YECL DSM Supervisor. • Provide directions to the YEC Energy Conservation Manager and the YECL DSM Supervisor on the reports and documents to be filed with the YUB, review and approve these documents and file them. • Work with the YEC Energy Conservation Manager and YECL DSM Supervisor to address comments from the YUB and interveners.
YEC Energy Conservation Coordinator	YEC	• Maintain the tracking system, control the quality of the data inputted into the system. • Extract reports from the accounting system and the tracking system for the YEC Energy Conservation Manager (KPIs, charts, etc.). • Supports the YEC Energy Conservation Manager with the development of quarterly or annual reports. • Support the YEC Energy Conservation Manager with EM&V, with selecting the EM&V Contractor, and with the coordination with the EM&V Contractor. • Support the YEC Energy Conservation Manager with selecting technical experts as needed, and with the coordination with these experts. • Provide technical assistance to all inCharge personnel as needed.
YECL Back-Office Coordinator	YECL	• Handles applications and completion forms. • Feeds the tracking system with transactional information as required in the operation manual. • Proceeds with in-situ verification of a few transactions (spot-check verifications that are going to be selected randomly).
YECL Billing Department	YECL	• Send utility billing data to EM&V Contractor as needed and when needed, directly to the contractor, and under a confidentiality agreement with the contractor.
YEC Finance	YEC	• Support the YEC Energy Conservation Manager with program time and expense tracking based on the work package structure/budget breakdown structure (WPS/BBS).
YEC Information Technology (IT) Department	YEC	• Support the YEC Energy Conservation Coordinator with tracking system maintenance. • Collaborate with the Communication Contractor to monitor traffic on the inCharge website.

Position	Payroll	Role/Responsibility with Regard to EM&V
Communications Contractor	Contractor for YEC	• Record keeping on the engagement and communication activities to be determined during the set-up stage.
YECL DSM Supervisor	YECL	• Jointly accountable with YEC Energy Conservation Manager for deliverables (e.g. schedule, scope, budget, resources) as outlined in the Demand Side Management Program Portfolio. • Jointly report to YEC/YECL Management Committee in coordination with YEC Energy Conservation Manager. • Coordinate with YEC Energy Conservation Manager to ensure business needs are met. • Review and approve the detailed work plan when updated by the YEC Energy Conservation Manager. • QC/QA of all of the communication materials being generated by the YEC Energy Conservation Manager and the Communications Contractor. • Record keeping on the engagement and communication activities to be determined during the set-up stage.
YECL Communications Coordinator	YECL	• Support YECL DSM Supervisor as needed.
Customer Engagement Officer	YECL	• Log the events or actions in order to compute the engagement KPIs. • Log program transactions (for example: program applications) that YECL channels to YECL Back-Office Coordinator with time stamps. • Track incentive reimbursements coming from YEC; and make sure there are no discrepancies between the tracking information of YECL and that of YEC. • Regarding the above, investigate any discrepancy as soon as possible. • Gather data on direct program time and expenses on YECL side and provide to YEC as part of quarterly reporting, present the time and expenses based on the WPS/BBS.
Yukon Utility Board (YUB)	YUB	• Look out for the interests of the rate payers and authorize the use of rate payers' monies on DSM. • As such, the YUB requires DSM to be implemented in a rigorous, cost-effective and optimal manner. All documents filed with them should demonstrate these attributes. • They achieve the above by asking questions and making comments on the reporting and planning documents filed with them; in particular the EM&V reports.
Evaluation, Measurement and Verification (EM&V) Contractor[7]	Contractor for YEC	• Finalize the evaluation, measurement and verification plan. o Review the tracking system and procedures, and recommend changes to maximize the value of EM&V. o Establish key "deemed" values to be used in the tracking system such as deemed savings for certain prescriptive conservation measures, a deemed net-to-gross ratio, and so on (Refer to Section 2.7 for more details). o Collect some additional market baseline information if and as needed.

[7] Refer to Section 4 for more details.

Position	Payroll	Role/Responsibility with Regard to EM&V
		• Carry out a process evaluation study when the DSM portfolio will have had a few quarters of operation (2 to 6). o Do some quality control/quality assurance of the program impacts as computed by the tracking system. • Carry out an impact evaluation study during the last year of operation of the DSM portfolio to validate the program impacts as computed by the tracking system.
Expert Consultants	Contrac-tors for YEC	• Support inCharge staff as required, to update the prescriptive incentive lists (both the incentive level and the eligible products). • Carry out project-level M&V on larger projects (like HE Refrigeration projects, or the residential innovative heating system projects).

Readers can refer to Section 4 of the PIP for additional details about the roles and responsibilities of the above positions in the context of program launch and operation, including their roles and responsibilities beyond EM&V.

2.7 Technical Reference Manual and Deemed Savings

The Utilities envision working with the EM&V contractor to build and verify a technical reference manual (TRM)[8]. The TRM will then be used to track program performance and evaluate program impacts.

A TRM is a repository of all of the project inputs and assumptions (PIAs) used to compute the program impact of *prescriptive conservation measures*. Most of the "smaller" energy conservation measures in the program portfolio will be treated as prescriptive conservation measures (for example the residential LED lamps, automotive heater timer, and ENERGY STAR Computers).

Each PIA usually includes the following items:

- Data to estimate impact and compute cost-effectiveness tests: Annual electricity savings, peak demand savings, measure incremental cost, and measure lifetime.
- Other natural resource savings and interactive effects: for example water and fossil fuels.
- Justification of all of the above including: algorithms, engineering equations and/or engineering model, inputs and assumptions, detailed cost information, and sources.
- Logs of the changes in the PIAs and justifications.
- Estimates of expected program attribution percentage (stipulated net-to-gross-ratio or NTG ratio).

The use of PIAs to estimate program impact is often referred to as the "deemed savings approach". The deemed savings approach will be recommended when the savings and rebate per prescriptive measure will not justify investing in field measurements, when a sampling approach will be cost-prohibitive given the level of funding of evaluation in absolute terms, and when savings cannot be established through utility billing data analysis. For example, this will be the case for residential LED lamps, automotive heater timers, and ENERGY STAR Computers.

[8] Note: A preliminary version *of the TRM was created as part of the CPR and the program design report.*

The creation, verification and continuous update of a TRM is an organized approach to the use of deemed-savings estimates. Every month new evaluation reports are being filed in North America and some of these evaluations are performed in larger jurisdictions with more resources and – in some cases – they include actual field measurements, surveying or sophisticated billing analysis to back the assumptions. The TRM is a tool to ensure continuous improvement of the deem-savings estimates; with time, the DSM staff and evaluators will gather and aggregate better assumptions based on new evaluation results in other North-American jurisdictions, as relevant.

3. Overview of EM&V for the Proposed DSM Portfolio

This section introduces the general approach to evaluation for the proposed DSM portfolio during the next 5-year operation window. This introduction is organized into the following sub sections:

- Evaluation scope
- Main evaluation work packages
- Evaluation schedule

3.1 Evaluation Scope

Evaluation will encompass all of the programs and programs elements that are recommended for the Utilities' initial DSM portfolio. The EM&V contractor will be expected to allocate resources among the elements of the DSM portfolio to maximize the overall value of the evaluation work. Consequently, they will need to be provided with a broad description of the DSM portfolio, projections and budget, as provided below.

DSM Design Principles and Portfolio Structure

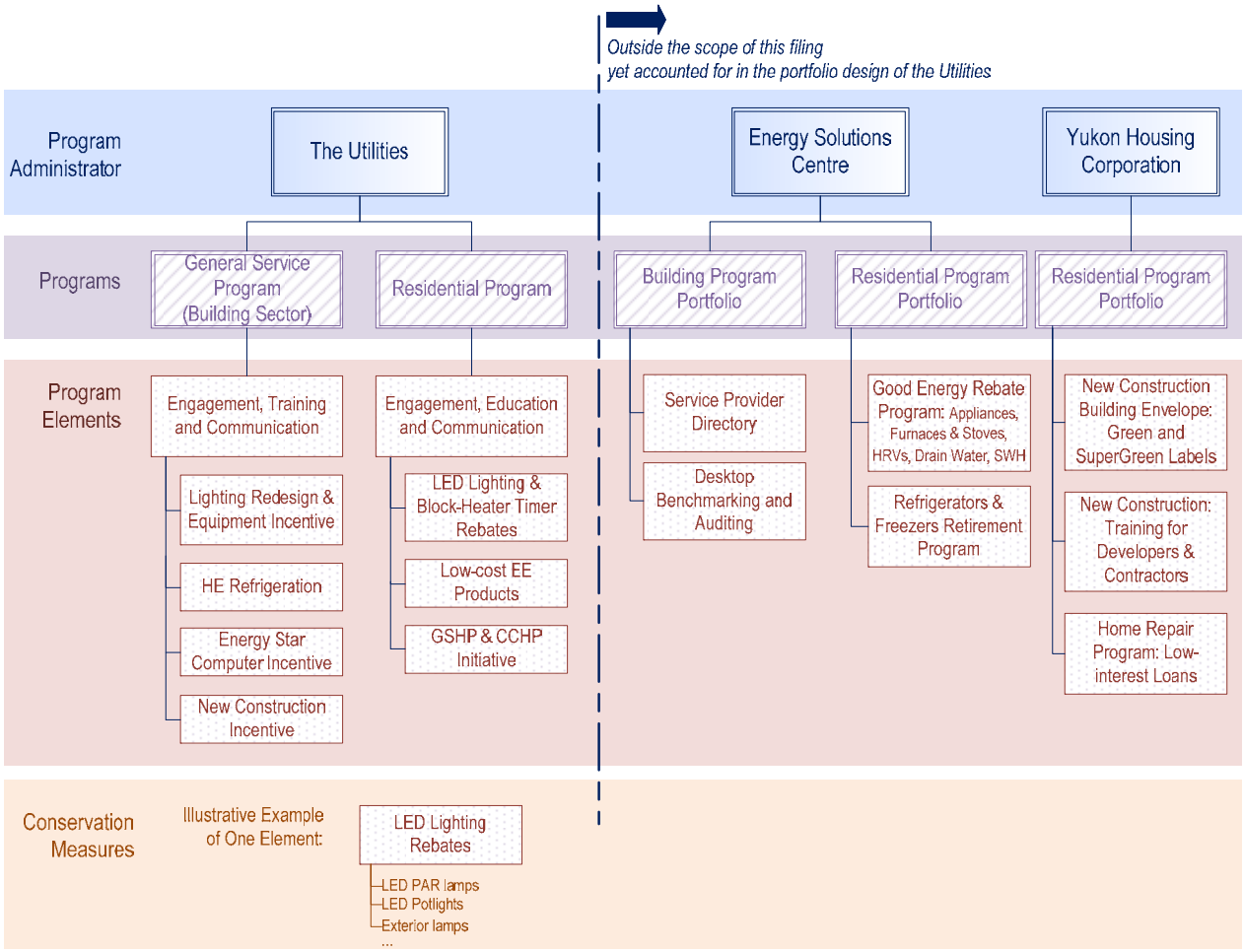
Two broad solutions-based programs are presented, each with multiple program elements: the General Service Program and the Residential Program. The objective was to offer customers a broad suite of options to meet their electricity management needs, rather than forcing customers to sort through a variety of individual programs.

Several specific design guidelines were applied to the programs presented. Those that are relevant to the evaluators are:

- The Utilities should retain design flexibility to enable program implementers to adjust specific designs as dictated by customer response and evaluation results.
- The Utilities should ensure that the program offerings complement existing energy initiatives in the Yukon and minimize duplication or potential customer confusion. To this end, there has been extensive collaboration with local entities such as the Energy Solutions Centre, Yukon Housing, City of Whitehorse and others.

Exhibit 2 presents the proposed overall portfolio of the Utilities' electricity programs. It also shows the current complementary energy programs offered by the Energy Solutions Centre and Yukon Housing.

Exhibit 2: Portfolio Structure



The portfolio in Exhibit 2 is the starting point for the Utilities. It is anticipated that timely adjustments will be made in response to feedback from customers and trade allies as well as the performance of individual programs. These changes will be documented through the internal performance reports, and annual budgeting and planning documentation.

DSM Portfolio Projections and Budget

Exhibit 3 and Exhibit 4 present an overview of the portfolio budget, impact projections, and Benefit/Cost results as anticipated before the preparation and launch stage.

The EM&V contractor should allocate evaluation resources among the program elements in a manner that is commensurate with the expected DSM expenditures and impacts for each. This EM&V plan already accounts for the importance of the program elements relative to each other based on budget and projections; however, the EM&V contractor will be provided with flexibility to further refine the methodology and resource allocation to reflect actual accounting reports, tracking results and KPIs.

The results are presented for the proposed five-year period by individual program element, program, as well as for the portfolio as a whole. The results are also organized within two scenarios:

- **Without Government Buildings:** This assumes that government owned buildings are not eligible to participate in the programs. Government buildings include buildings from all levels of government: federal, territorial, first nation, and municipal.
- **With Government Buildings[9]:** This assumes that all Yukon buildings are eligible to participate in the programs.

In each case, the results presented include:

- **Net Savings – Lifetime MWh:** These are the lifetime electricity savings attributed to (only) the measures implemented in the year shown and are inclusive of transmission and distribution losses.
- **Net Savings – Annual MWh**: These are the electricity savings that would occur in the milestone year shown due to the impacts of the measures implemented to date under the program. They are inclusive of T&D losses.
- **Utility Expenditure**: These show the associated incentive and non-incentive program costs that would be incurred in each milestone year.
- **Benefit/Cost Ratios:** These are the results of the standard benefit-cost tests. The acronyms refer to: the TRC – Total resource cost test; the PAC – Program administrator cost test; the PC – Participant cost test; and the RIM – Rate impact measure test. Seasoned evaluators will be accustomed to them. Explanations on these were provided in the Program Design Document. The definitions that were used are compliant with the 2001 California Standard Practice Manual.[10]

Notes to support the interpretation of Exhibit 3 and Exhibit 4:

- There is no incremental cost to the Participant to purchase an ENERGY STAR computer.
- In case of inconsistencies, the Exhibit in the Program Design Report should prevail.

[9] For example, the DSM plan could include a caveat that some level(s) of government will not participate in DSM programs that are funded from rate-base.

[10] **CPUC**, *California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects*, October 2001, USA, [ONLINE] as seen on March 26, 2013, URL: http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

Exhibit 3: Portfolio Results Excluding Government Buildings

Program Elements		Net Savings with T&D Losses							Utility Expenditure ($1,000s)						Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - excluding gov. buildings	Lifetime MWh:	0	2,476	6,240	7,132	7,132	22,981	Incentive:	$4	$96	$213	$239	$222	$773	1.1	2.8	2.5	0.9
	Annual MWh:	0	333	1,140	2,062	2,985	N/A	Non-Incen.:	$77	$78	$81	$85	$111	$432				
	Coincident kW:	0	79	269	486	703	N/A	Total:	$81	$175	$294	$323	$333	$1,205				
New Construction Incentive - excluding gov. buildings	Lifetime MWh:	0	306	1,377	2,142	2,448	6,273	Incentive:	$0	$4	$19	$30	$34	$87	4.2	4.9	6.3	1.0
	Annual MWh:	0	15	84	191	314	N/A	Non-Incen.:	$4	$31	$5	$31	$12	$82				
	Coincident kW:	0	3	19	44	72	N/A	Total:	$4	$35	$24	$60	$46	$169				
High-Efficiency Refrigeration Incentive - excluding gov. buildings	Lifetime MWh:	0	0	6,301	0	6,301	12,602	Incentive:	$0	$0	$122	$0	$122	$243	3.2	4.5	4.2	1.0
	Annual MWh:	0	0	630	630	1,260	N/A	Non-Incen.:	$10	$91	$17	$54	$42	$214				
	Coincident kW:	0	0	72	72	143	N/A	Total:	$10	$91	$138	$54	$163	$458				
Energy Star Computer - excluding gov. buildings	Lifetime MWh:	32	205	335	0	0	573	Incentive:	$2	$10	$17	$0	$0	$29	1.8	1.2	*	0.6
	Annual MWh:	8	59	143	143	135	N/A	Non-Incen.:	$26	$12	$15	$2	$5	$60				
	Coincident kW:	1	11	26	26	24	N/A	Total:	$28	$22	$32	$2	$5	$89				
Engagement, Education and Communication - excluding gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$167	$251	$224	$175	$217	$1,034				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$167	$251	$224	$175	$217	$1,034				
Total General Service Program excl. gov. buildings	Lifetime MWh:	32	2,988	14,253	9,274	15,881	42,428	Incentive:	$5	$111	$371	$268	$377	$1,132	1.3	2.1	3.2	0.8
	Annual MWh:	8	408	1,997	3,027	4,693	N/A	Non-Incen.:	$284	$463	$341	$346	$387	$1,822				
	Coincident kW:	1	93	385	627	942	N/A	Total:	$290	$574	$712	$615	$764	$2,954				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,747	10,294	21,319	17,243	23,504	75,108	Incentive:	$56	$219	$474	$380	$477	$1,606	1.3	2.1	2.9	0.8
	Annual MWh:	221	1,167	3,287	4,887	7,098	N/A	Non-Incen.:	$706	$824	$670	$703	$815	$3,718				
	Coincident kW:	77	363	845	1,290	1,800	N/A	Total:	$762	$1,043	$1,145	$1,083	$1,292	$5,325				

Exhibit 4: Portfolio Results Including Government Buildings

Program Elements	Net Savings with T&D Losses							Utility Expenditure ($1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
Lighting Redesign and Equipm't Incentive - including gov. buildings	Lifetime MWh:	0	4,314	10,711	12,241	12,241	39,506	Incentive:	$6	$135	$294	$327	$299	$1,062	1.2	3.8	2.4	0.9
	Annual MWh:	0	507	1,731	3,128	4,526	N/A	Non-Incen.:	$81	$77	$66	$72	$127	$425				
	Coincident kW:	0	127	432	781	1,129	N/A	Total:	$88	$213	$360	$400	$427	$1,487				
New Construction Incentive - including gov. buildings	Lifetime MWh:	0	471	2,118	3,295	3,766	9,651	Incentive:	$0	$6	$25	$39	$45	$115	4.7	6.1	6.7	1.0
	Annual MWh:	0	24	129	294	483	N/A	Non-Incen.:	$28	$9	$6	$33	$16	$93				
	Coincident kW:	0	5	30	67	110	N/A	Total:	$28	$15	$32	$72	$61	$208				
High-Efficiency Refrigeration Incentive - including gov. buildings	Lifetime MWh:	0	0	7,580	0	7,580	15,161	Incentive:	$0	$0	$132	$0	$132	$263	3.2	4.3	4.6	1.0
	Annual MWh:	0	0	694	694	1,388	N/A	Non-Incen.:	$36	$100	$19	$86	$49	$290				
	Coincident kW:	0	0	80	80	161	N/A	Total:	$36	$100	$151	$86	$180	$553				
Energy Star Computer - including gov. buildings	Lifetime MWh:	107	681	1,111	0	0	1,899	Incentive:	$6	$35	$57	$0	$0	$98	2.0	1.3	*	0.6
	Annual MWh:	27	197	475	475	448	N/A	Non-Incen.:	$36	$52	$74	$6	$17	$185				
	Coincident kW:	5	35	85	85	80	N/A	Total:	$41	$88	$131	$6	$17	$284				
Engagement, Education and Communication - including gov. buildings	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen.:	$202	$290	$255	$200	$252	$1,199				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$202	$290	$255	$200	$252	$1,199				
Total General Service Program incl. gov. buildings	Lifetime MWh:	107	5,466	21,520	15,536	23,587	66,217	Incentive:	$12	$176	$508	$367	$476	$1,538	1.3	2.5	3.2	0.8
	Annual MWh:	27	728	3,029	4,591	6,845	N/A	Non-Incen.:	$383	$529	$420	$398	$461	$2,192				
	Coincident kW:	5	167	627	1,013	1,480	N/A	Total:	$395	$705	$928	$765	$937	$3,730				
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	718	3,149	3,207	3,207	3,207	13,487	Incentive:	$12	$51	$52	$52	$52	$217	1.9	3.0	2.5	1.0
	Annual MWh:	36	199	368	537	705	N/A	Non-Incen:	$82	$84	$55	$59	$107	$387				
	Coincident kW:	13	71	131	191	252	N/A	Total:	$94	$135	$106	$111	$159	$604				
Low-cost Energy Efficient Products	Lifetime MWh:	1,849	3,969	3,672	3,540	3,342	16,371	Incentive:	$34	$48	$43	$36	$30	$192	1.8	2.7	2.8	1.0
	Annual MWh:	169	543	896	1,236	1,558	N/A	Non-Incen:	$165	$179	$145	$153	$169	$811				
	Coincident kW:	60	194	319	441	556	N/A	Total:	$199	$227	$188	$189	$199	$1,003				
New-construction CCHP and GSHP Initiative	Lifetime MWh:	148	188	188	1,223	1,075	2,821	Incentive:	$5	$9	$9	$24	$19	$65	0.9	1.7	1.2	0.8
	Annual MWh:	7	17	26	87	141	N/A	Non-Incen:	$18	$34	$28	$39	$24	$144				
	Coincident kW:	3	6	9	31	50	N/A	Total:	$23	$43	$37	$63	$43	$209				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	$0	$0	$0	$0	$0	$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	$113	$130	$134	$138	$142	$657				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	$113	$130	$134	$138	$142	$657				
Total for the Residential Program	Lifetime MWh:	2,715	7,306	7,066	7,969	7,623	32,679	Incentive:	$51	$108	$104	$112	$100	$474	1.4	2.0	2.4	0.9
	Annual MWh:	213	759	1,289	1,860	2,405	N/A	Non-Incen:	$379	$427	$361	$389	$443	$1,999				
	Coincident kW:	76	271	460	664	858	N/A	Total:	$429	$535	$465	$501	$543	$2,473				
Grand Total All Programs Portfolio	Lifetime MWh:	2,822	12,772	28,586	23,505	31,210	98,896	Incentive:	$63	$284	$612	$478	$576	$2,012	1.4	2.3	2.9	0.8
	Annual MWh:	240	1,487	4,318	6,451	9,250	N/A	Non-Incen.:	$762	$957	$782	$787	$904	$4,191				
	Coincident kW:	81	438	1,087	1,677	2,338	N/A	Total:	$824	$1,240	$1,393	$1,266	$1,480	$6,203				

3.2. Main Evaluation Work Packages

Section 3.2 provides a description of the types of evaluation required, summarizes the experimental approach anticipated, and then lists of all the physical deliverables that will be part of the EM&V work.

The approach presented in Section 3.2 is preliminary, and should be considered as a suite of options which, as a whole, represent EM&V best practice.

The general approach is based on four main work packages:

- **Finalization of the EM&V Plan** – to be initiated between the fourth and the sixth quarter after the start of the program operation window (that is: between Y1-Q4 and Y2-Q2).
- **Process Evaluation Study** (EM&V Study #1) – to be initiated two to six quarters after the first DSM incentive transaction (that is: sometime between Y2-Q2 and Y3-Q2 if the first-transaction milestones are passed according to the plan).
- **Impact Evaluation Study** (EM&V Study #2) – to be initiated five to eight quarters before the end of the program window (that is: between Y4-Q1 and Y4-Q4 based on a 5-year operation window).
- **Project-Level M&V Studies** – the evaluators will be convened to perform certain project-level M&V planning, analysis and reporting tasks as needed many times thorough the program operation window.

The four work packages are described below. They are also laid out in a Gantt chart in Section 3.3 Evaluation Schedule.

Finalization of the EM&V Plan

The final evaluation scope will be determined through initial collaboration with the EM&V contractor once selected, and consultation with the YEC/YECL management committee and YUB. It is expected that the contractor will be selected and under a contract between the fourth or sixth quarter of program operation. Finalizing the EM&V plan should take about three months to complete.

Finalizing the EM&V Plan encompasses the following activities:

- Review, edit, and adapt the EM&V plan based on the outcomes of the activities below.
- Collect and review all program documentation so far: the CPR report, market characterization reports, program design document, PIP, early reports from the preparation and launch stage, transactional and operational materials, communication materials and meeting minutes.
- Carry out a few in-depth interviews with YEC and YECL staff, as needed.
- Narrow down the methodological options or suggest other innovative methods to maximize value of EM&V, while in compliance with the California Evaluation Framework.
- Compute the detailed EM&V budget using the actual professional rates of the contractor staff, based on the final recommended approach and based on the rate inflation forecast.
- Identify gaps in the market characterization reports, recommend and carry out some early baseline data collection tasks, as needed.

- Check the logic models for soundness and suggest improvements, based on the result of the activity and above and as needed.
- Review, edit and adapt the TRM based on a desk review of the TRM, on a comparison with other North-American TRMs and on a jurisdictional scan of relevant evaluation reports.
- Establish stipulated net-to-gross ratios for all program elements and measures based on a jurisdictional scan of relevant evaluation reports, and experience.
- Review the transactional and operational materials (application and internal forms), and the tracking system and identify: (i) superfluous information items, and (ii) missing information items that will be required for EM&V purpose. Suggest corrective actions as needed.
- Review and edit the protocols regarding site verification of conservation measures under the responsibility of the administration staff.
- Use the existing program theory and logic models to assess whether the theory is plausible and suggest improvements.

The final EM&V plan should include the following items either in the body of the document or as part of the appendix:

- A verified TRM that will be used to generate KPIs and performance reports for all program elements.
- A revised list of incentive levels for all prescriptive measures.
- Stipulated NTG ratios for all program elements accounting for the above.
- A new version of evaluation indicators and baseline levels (as required) to assess the effectiveness of the delivery mechanism.
- A list of corrective actions on the transactional materials and tracking system, as needed.
- A formal approval of the site-verification protocols and approach to documenting the verifications.

Process Evaluation Study

The following paragraphs provide a description of the type of evaluation required and summarize the experimental approach anticipated, the major deliverables and special methods sought from the evaluation contractor.

The process evaluation study (EM&V Study #1) will be initiated two to six quarters after the first DSM incentive transaction. It should take about six months to complete.

The purpose of a process evaluation is to identify corrective actions to improve the program uptake, impact and cost-effectiveness. The rationale behind carrying out the process evaluation early after the launch of the program is to achieve the benefits of the corrective actions before the end of the current program operation window.

Evaluators will be asked to suggest corrective actions applicable to the incentive levels, communication strategy, transactional infrastructure, tracking and performance reporting, site verifications, delivery approach and institutional framework, and program management practices. Evaluators can go as far as suggesting pulling some program elements out of the market if these elements are deemed ineffective.

Evaluators will suggest corrective actions in light of:

- A consultation with relevant market actors (e.g.: participants, non-participants, supply-side actors and relevant stakeholders) through surveying, interviewing and/or others.
- The desk review of the program database content, accounting reports, communication tactics and materials, performance reports, and site verification documentation.

EM&V Study #1 will also include a few impact-evaluation and cost-effectiveness evaluation components.

- Evaluators will work on updating and tuning the TRM based on any new information that might have come up since the finalization of the EM&V plan – like new relevant evaluation reports from other jurisdictions, new information collected through program tracking, observations made during site verification, or market insights gained during market consultation.
- Evaluators will work on carrying out the ex-post cost-effectiveness tests based on the most recent program data. Evaluators are encouraged to use the same modeling tool used by the administration staff to generate the annual performance report, modify it as required, and validate it to make sure that the reports being filed with the YUB by the administration staff are sound.

Generic Process Evaluation Research Questions: The following are generic research questions that evaluators will be asked to answer as part of the process evaluation study. An answer will be asked for each of the program elements that are laid out in Section 4. Where specific questions or nuances to the generic questions below are needed for each program element, they are laid out in Section 4.

1. Is the program design (theory, strategy, tactics and incentive level) effective at realizing savings (kWh and kW)?
2. Are the program management and operational and transactional infrastructure effective and efficient at delivering the tactics, mitigating risks (fraud and the like), supporting tracking and evaluation, and improving customer satisfaction?
3. Is the program communication strategy effective and efficient at generating uptake in the program element?
4. Is the approach to estimating the impacts as part of program tracking rigorous and effective at establishing DSM as a credible and reliable resource?
5. How much of the impact should be attributed to the program administrator – early estimate for program tracking purposes? (that is: an early stipulated NTG ratios)
6. Is the approach to carrying out the ex-post cost-effectiveness tests sound and effective at supporting DSM planning decisions?

When answering all of the questions above, evaluators will seek to recommend solutions to the issues that might be uncovered and improvements to make the DSM portfolio more effective and efficient.

The main deliverable of EM&V Study #1 will be a Process Evaluation Report at the culmination of the study. The report should include the following items either in the body of the document or as part of the appendix:

- A list of corrective actions, a justification for each, and advice on how to roll these out (who? when? how? how much?).
- A new version of verified TRM.

- A new version of stipulated NTG ratios.
- Verified KPIs for program operation up to a month before the delivery of the report;
- Cost-effectiveness test results based on actual program data for program operation up to a month before the delivery of the report.
- A list of recommendations applicable to EM&V Study #2 and an updated EM&V plan accounting for these recommendations.

Impact Evaluation Study

The impact evaluation study (EM&V Study #2) will mostly consist of impact evaluation research questions. Specific research questions will be laid out for each project element in Section 4. Study #2 will be initiated five to eight quarters before the end of the program window. It is expected that the study will take about twelve months to complete; a first draft should be presented to the YEC/YECL management committee three months before the end of the program operation window (about Y5-Q3) and the final report should be filed with the YUB three months after the end of the program window at the most (about Y6-Q1).

The purpose of impact evaluation is to increase the level of precision and accuracy of the impact estimates filed with the YUB. Evaluators will increase the accuracy and precision of the impact estimates through:

- Additional data collection activities and impact evaluation methods as presented in Section 4.
- Updating and tuning the TRM based on any new information that might have come up since the culmination of EM&V Study #1. The approach will be similar to the one used during Study #1.

Evaluators will generate verified KPIs for program operation up to the end of the program operation window, and then they will carry out the ex-post cost-effectiveness tests based on these KPIs.

Evaluators will observe the changes in the market – whether induced by the DSM portfolio or otherwise – through consultation with relevant market actors through surveying, interviewing and/or other means. It is expected that the same evaluation contractors will have cumulated sufficient relevant market observations to provide an insightful and educated opinion regarding the evolution of the Yukon market and the implications on the current and future DSM portfolio. The evaluators will have accumulated these observations through accessing the market characterization reports as well as research and consultation in Yukon as part of the finalization of the EM&V plan, the process evaluation study, the project-level M&V work, and the impact evaluation study.

Evaluators will be expected to provide an opinion on whether program elements became irrelevant or whether new opportunities have arisen. Program evaluators will be able to make high-level recommendations on the future of DSM in Yukon that will be used to design the next generation of programs.

Generic Impact Evaluation Research Questions: The following are generic research questions that evaluators will be asked to answer as part of the impact evaluation study. Specific questions for each of the program elements are laid out in Section 4.

1. How much of the impact claimed by the program administrator has actually been realized? (i.e. the realization ratio)
2. How much of the impact should be attributed to the program administrator – what is the final estimate? (i.e. the final stipulated NTG)

3. What are the actual ex-post results of the cost-effectiveness tests?
4. Have the program operation standards and procedures been complied with and properly documented?
5. What are the implications of the evolution of the Yukon market on the program design and delivery mechanisms?

When answering all of the questions above, evaluators will seek to make high-level recommendations to make the next generation of Yukon DSM programs more effective and efficient.

The main deliverable of EM&V Study #2 will be an Impact Evaluation Report at the culmination of the study. The report should include the following items either in the body of the document or as part of the appendix:

- A new version of verified TRM.
- A new version of stipulated NTG ratios.
- A realization ratio for each of the program elements.
- Verified KPIs for program operation up to the end of the program operation window based on the above.
- Cost-effectiveness test results based on actual program data for program operation up to the end of the program operation window.
- Evaluation indicators, comparison with baseline levels, comparison with targets and conclusions on the effectiveness of the DSM portfolio at transforming the market.
- Recommendations on the next generation of programs in Yukon including but not limited to: programs that became (or are about to become) irrelevant, ineffective or counter-productive; exit strategies or overhaul of existing program elements; significant changes in the delivery approach; and new DSM opportunities to be investigated.

The evaluators will provide a justification for each of the recommendations they make.

Project-Level M&V Studies

The *Project-Level M&V Studies* work package consist of a series of call ups for the evaluators to perform project-level M&V activities including the planning of project-level M&V, the interpretation and analysis of measurements, and drafting of M&V reports. The outcomes of this work are to be integrated in EM&V Study #2; however the program administrators should be able to trigger these activities independently from the course of Study #1 and #2.

Projects that will need M&V are:

- **General Service high-efficiency refrigeration projects in food retail stores and ice rinks.** These projects are planned to occur in two waves: a first wave is planned to start around Y2-Q2, construction is to end on Y3-Q3, and the post-retrofit measurement period – expected to last for one year – is to end around Y4-Q3. The second wave will start on Y4-Q2 then follow a similar schedule. The completion of the M&V work for that second wave falls outside of the program window.
- **Residential innovative heating projects.** These projects are planned to be implemented between Y1-Q4 and Y3-Q2, and thus the post-retrofit measurement period – expected to last for one year – is to end between Y2-Q4 and Y3-Q3.

The notional schedules presented above depend on the willingness of participants and market stakeholders to carry out these projects and thus the administrator will need flexibility from the evaluators on the timeline.

In addition to impact-evaluation purposes, project-level M&V work has the following objectives:

- Feedback verified information on project savings to the market through case studies and other communication tactics to boost the uptake of the programs. – It is assumed that actual M&V results will reinforce the case studies by making them more credible.
- Validate the viability of technologies in the Yukon, identify risks, and provide insights that will be fed in the planning and decision whether to roll out a full-scale residential innovative heating incentive program.

The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days.

The specific M&V tasks for each project include:

- Collect pre-retrofit utility bills and information about the project and building.
- Draft a project-specific M&V plan.
- Collect post-retrofit utility-bills, as well as routine and non-routine adjustment parameters.
- Supervise or carry out at least one site visit and document field observations.
- Carry out M&V analysis in accordance with the plan.
- Draft an M&V report.

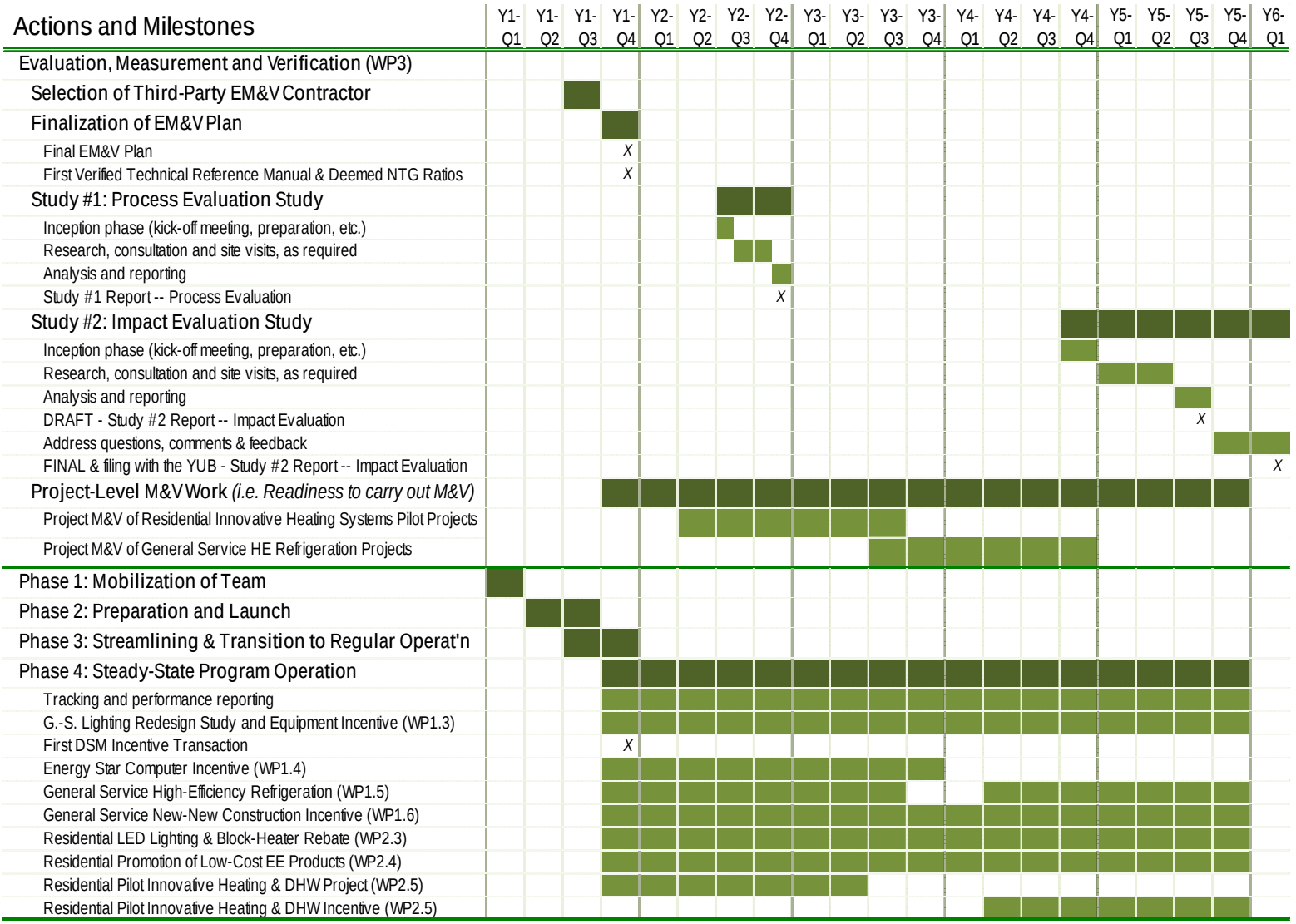
The deliverables for each project include: an M&V plan, and a final M&V report.

Evaluators will be able to suggest other methodological options and approaches they deem relevant, as long as the suggested approaches align with the IPMVP methodological options.

3.3 Evaluation Schedule

Exhibit 5 shows a schedule for EM&V as part of the 5-year program operation window. The EM&V activities, deliverables and milestones are stacked up above a high-level schedule of the program implementation and operations.

Exhibit 5: High-Level Gantt Chart of the Evaluation, Measurement and Verification Work



The schedule for EM&V shown in Exhibit 5 is approximate. The DSM administration will have the flexibility to shuffle the work packages in the 5-year operation window depending on the status of the DSM portfolio; for example the *Finalization of the EM&V Plan* could be postponed by up to two quarters, *Study #1* could be postponed by up to three quarters and/or *Study #2* could be started up to three quarters earlier. However, Y6-Q1 for the filing of the impact evaluation report is a hard deadline.

4. Program-Specific Evaluation Implications

This section provides a description of the specific EM&V requirements for each of the seven program elements that, together, make up the Yukon DSM program portfolio. The discussion is organized and presented by program element, as outlined below.

- General Service Program, which consists of the following four program elements:
  - Lighting Redesign and Equipment Incentive
  - High Efficiency Refrigeration Program
  - Energy Star Computer Incentive
  - New Construction Incentive
- Residential Program, which consists of the following three program elements:
  - LED Lighting and Automotive Heater Timer Rebate
  - Promotion of Low-Cost Energy Efficient Products
  - GSHP and CCHP Initiative

For each program element noted above, the discussion addresses the following areas:

- **Program Description Summary**

  It is standard practice to provide a program description summary as part of EM&V plans. This enables the evaluators to appreciate the program type and the nature of the conservation measures/projects being promoted and, therefore, to more easily establish their evaluation approach. The program theory is also essential to developing indicators that will enable performance-based management and planning.

- **Evaluation Considerations**

  The evaluation considerations are specific to each of the seven program elements. They build on the general approach presented in Section 3. All of the seven program elements will concurrently be subjected to a process evaluation (Study #1), and then an impact evaluation (Study #2). The discussion of evaluation considerations for each program element is further organized into the following areas:
  - Management-by-objective framework
  - Evaluation research questions
  - Suggested evaluation methods and level of rigor

4.1 General Service Lighting Redesign and Equipment Incentive

4.1.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers to have their lighting systems retrofitted. The total incentive will be the sum of three layers:

- Lighting redesign incentive
- Custom lighting incentive
- Prescriptive LED lighting incentive

The Utilities will pay an incentive to building owners/managers to have a lighting redesign conducted in their building. The purpose of the lighting redesign will be to design the optimal lighting system in term of visual comfort, ease of maintenance, and electricity savings considering the existing spaces, windows and fixtures. The incentive for the redesign work will be determined using a dollar-per-square foot rate. The lighting designers will be required to develop designs that meet minimum power density thresholds.

The custom lighting incentive includes a base incentive for the equipment and installation determined using a dollar per kilowatt-hour of annual savings rate. This approach provides flexibility in choice of lighting technologies and also allows contractors and designers to be innovative.

For the prescriptive LED incentive layer, the Utilities will add a flat amount of money per unit for LED products selected from a prescriptive list of eligible products.

Building owners/managers will be able to combine the custom incentive layer, the LED prescriptive incentive layer, and the lighting redesign incentive layer to best suit their needs and to generate a larger incentive for LED technologies: the initial-cost hurdle is higher for the LED technologies and the Utilities have a goal of accelerating market penetration of these products. The prescriptive list of eligible LED products will be consistent with that used in the Residential Program.

Eligible Measures

The proposed incentive levels as well as archetype projects are presented in Exhibit 6 to Exhibit 9.

Exhibit 6: Archetype Lighting Conservation Projects – Custom Incentive Layers for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM91	Lighting Redesign Study	0.00 kWh/ft2	.00000 kW/ft2	110%	$1.20/ft2	16.0 yr	$0.40/ft2	11,759 ft2
ECM80	Typical Lighting Project in	1.99 kWh/ft2	.00060 kW/ft2	95%	$1.40/ft2	15.4 yr	$0.16/ft2	15,000 ft2
ECM81	Typical Lighting Project in Existing Bldg - Food Retail	4.85 kWh/ft2	.00092 kW/ft2	95%	$2.30/ft2	15.4 yr	$0.39/ft2	30,000 ft2
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail	3.64 kWh/ft2	.00072 kW/ft2	95%	$1.90/ft2	15.4 yr	$0.29/ft2	10,000 ft2
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel	1.84 kWh/ft2	.00036 kW/ft2	95%	$2.10/ft2	11.5 yr	$0.15/ft2	20,000 ft2
ECM86	Typical Lighting Project in Existing Bldg - Restaurant	6.65 kWh/ft2	.00140 kW/ft2	95%	$3.10/ft2	13.0 yr	$0.53/ft2	4,000 ft2
ECM87	Typical Lighting Project in Existing Bldg - Recreation	1.79 kWh/ft2	.00043 kW/ft2	95%	$1.90/ft2	15.7 yr	$0.14/ft2	25,000 ft2
ECM88	Typical Lighting Project in Existing Bldg - Warehouse	1.85 kWh/ft2	.00045 kW/ft2	95%	$2.00/ft2	15.7 yr	$0.15/ft2	30,000 ft2

Exhibit 7: Prescriptive LED Incentive Layer for Non-Government Buildings

ID	Measure Short Name	Level of Incentive
ECM92	Commercial 12W LED A19 Bulb	$18.00/unit
ECM93	Commercial 8W LED A19 Bulb	$12.00/unit
ECM94	Commercial LED MR16 Bulbs	$10.00/unit
ECM95	Commercial LED PAR30 Bulbs	$20.00/unit
ECM96	Commercial LED PAR38 Bulbs	$20.00/unit
ECM97	Commercial Spot or task lighting	$10.00/unit

Exhibit 8: Archetype Lighting Conservation Projects – Custom Incentive Layer for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM912	Gov. Lighting Redesign Study	0.00 kWh/ft2	.00000 kW/ft2	100%	$1.20/ft2	20.0 yr	$0.24/ft2	26,209 ft2
ECM802	Gov. Typical Lighting Project in	1.99 kWh/ft2	.00060 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.10/ft2	15,000 ft2
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health	2.45 kWh/ft2	.00035 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.12/ft2	95,000 ft2
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education	1.15 kWh/ft2	.00042 kW/ft2	95%	$1.40/ft2	20.0 yr	$0.06/ft2	33,000 ft2
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation	1.79 kWh/ft2	.00043 kW/ft2	95%	$1.90/ft2	20.0 yr	$0.09/ft2	25,000 ft2
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse	1.85 kWh/ft2	.00045 kW/ft2	95%	$2.00/ft2	20.0 yr	$0.09/ft2	30,000 ft2

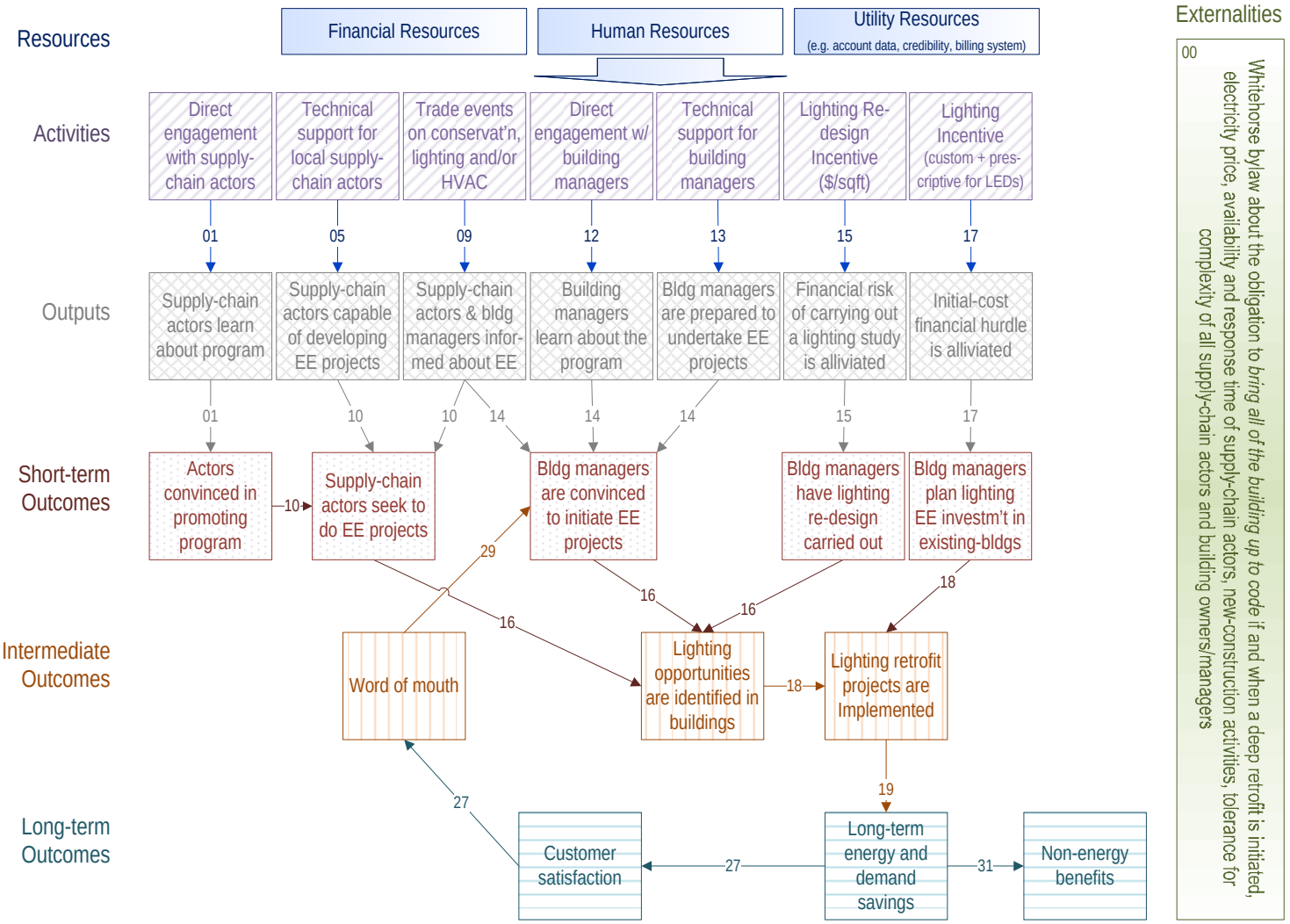
Exhibit 9: Prescriptive LED Incentive Layer for Government Buildings

ID	Measure Short Name	Level of Incentive
ECM922	Gov. Commercial 12W LED A19 Bulb	$10.80/unit
ECM932	Gov. Commercial 8W LED A19 Bulb	$7.20/unit
ECM942	Gov. Commercial LED MR16 Bulbs	$6.00/unit
ECM952	Gov. Commercial LED PAR30 Bulbs	$12.00/unit
ECM962	Gov. Commercial LED PAR38 Bulbs	$12.00/unit
ECM972	Gov. Commercial Spot or task lighting	$6.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below. The offering logic model is annotated from top (resource allocation) to bottom (intended impacts) in the table following the chart.

Exhibit 10: Logic Model for the General Service Lighting Redesign and Equipment Incentive



Link #	Narrative
00	Externalities: The program effectiveness and impact will be influenced by the following externalities: Whitehorse bylaws on the obligation to bring all of the buildings up to code if and when deep retrofits are initiated, the price of electricity, the availability and response time of supply-chain actors, new-construction activities, and tolerance for complexity of all supply-chain actors and building owners/managers. The program administrator should monitor these externalities and adapt the implementation approach as necessary.
01	Direct engagement with supply-chain actors: The Utilities will carry out direct engagement with electrical distributors, lighting designers, electrical contractors, as well as with HVAC contractors, HVAC designers, control designers and architects through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and engage with supply-chain actors so that they promote them.

Link #	Narrative
05	Technical support for local supply-chain actors: The Utilities will offer technical support to the supply-chain actors in two different forms: (1) hands-on training on the program tools, forms and procedures; on advanced electricity efficiency lighting design; and on the business aspects of electricity efficiency: energy audits, business cases, energy performance contracting, and electricity efficiency financing. (2) The Utilities will act as a broker to procure technical expertise from highly specialized lighting experts recruited throughout North America upon request from the local actors. In addition, the Utilities will disseminate information on recommended lighting equipment (brand-neutral, to the extent possible) in the form of printed brochures, newsletters or web content.
09	Trade events on conservation, lighting and/or HVAC: The Utilities propose to support any form of trade organizations or trade events by sponsoring and attending trade events that gather local building owners/managers and/or supply-chain actors. The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories, and share their lessons learned.
10	Supply-side actors will actively seek to develop projects because they were engaged with by the Utilities, because they were trained and are capable of offering electricity-efficiency services, and because they were provided with networking opportunities with potential clients (building owners/managers) at trade events.
12	Direct engagement with building managers: The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings; and through public relations activities like media advisories sent to the local newspapers and radio, web content, and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
13	Technical support for building managers: The Utilities will offer customized technical support to building owners/managers to help them to initiate projects. The Utilities could include support to plan investment in assets, and to identify in which buildings to develop projects; support to make optimal decisions on implementation and procurement approach, and support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities, because they were provided with technical support to decide where to start and how to do it, and because they networked with supply-side actors, perhaps at the trade events supported by the Utilities.
15	Lighting redesign incentive: The Utilities will pay an incentive to building owner/managers to have a lighting redesign study conducted in their building. The purpose of the lighting redesign study will be to design an optimized lighting system in term of visual comfort, ease of maintenance, and electricity savings, considering the existing spaces, windows and fixtures. The incentive will reduce the financial risk of investing in a pre-investment study, and will reduce the initial-cost hurdle of doing business with designers. The building managers will have lighting redesign studies carried out.
16	Electricity-efficient lighting opportunities are identified in the building because the supply-chain actors were seeking to develop new lighting projects, because building owners/managers agreed to initiate an electricity efficiency project and because the financial risk of carrying out a redesign study was alleviated.
17	Lighting equipment incentive: The Utilities will pay an incentive to building owners/managers to have their lighting systems retrofitted. This incentive will include a custom incentive layer and a prescriptive LED incentive layer. The custom incentive allows for flexibility in lighting technologies as well as the use of occupancy control, dimming and day lighting, etc. It pushes distributors, contractors and designers to be innovative. The purpose of the prescriptive LED incentive layer is to increase the level of incentive when LED technologies are used because the initial-cost hurdle is higher for LED technologies than for other technologies; and because LED lighting is a technology for which the Utilities would like to accelerate market penetration.
18	Electricity-efficient lighting retrofit projects are implemented because electricity-efficient lighting opportunities were identified and because the equipment and installation initial-cost financial hurdle was alleviated.
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings.

Link #	Narrative
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry; perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and have increased property value.

4.1.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 10 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 11. Performance indicators should be reviewed by the EM&V contractor to validate the theory.

Explanatory notes on Exhibit 11 and MBO frameworks in sections 4.2 to 4.7 are provided below:

- **Part A & Part B.** The MBO framework was divided into two parts:
  - Part A is for the key performance indicators (KPIs) that will be monitored by the administration staff through operations, application and incentive processing, and minimal record keeping of communications and engagement work. Then these KPI results are to be validated by the evaluators.
  - Part B is for the evaluation of market performance indicators. These indicators will be established by evaluators through surveying, consultation, research and analysis as part of the two main evaluation studies: process evaluation and impact evaluation.

- **Components of the MBO Framework:**
  - *Link # and Narrative* refers to the Logic Model for the program element. See Exhibit 10.
  - *Performance Indicators* are the metrics used as KPIs, the evaluation indicator.
  - *Sources* will tell the evaluators where the data needed to compute the indicators must come from. In Part A, most of this data is internal to the program administration: it will be contained either in the program documentation, tracking system or logs of communication and engagement activities.
  - Targets for Year 1 to 5: Goals the actual indicators will be compared against. Those presented below are preliminary and will be validated as laid out below.

- **Starting Point and Later Stages.** The MBO framework presented below is a starting point. After the delivery of this EM&V plan, it will go through various stages of validation and transformation: These stages are:
  - During startup, the launch team will review it and adapt it to its preferences and based on the record-keeping standards that are agreed on. This is why, in many cases, performance indicators are referred to as "*Suggested indicators or KPIs*".

- During the finalization of the EM&V plan, the launch team and evaluators will review the MBO framework and goals, and then sign off on it.
- During operation and on an annual basis, the program administration staff will be able to change the MBO framework and targets based on early results, challenges and market conditions. Whenever changes will be made, the administration staff will document the justifications for the evaluators to review.
- With each program evaluation report, the evaluators will present the MBO Framework with actual indicators against the latest targets.

- **Sum of Section 4.1 to 4.7.** Section 4.1 to 4.7 will present a MBO framework for each of the seven program elements in the portfolio. Such a breakdown creates an appearance of redundancies and overlaps on paper when in many cases the indicators will be the same. The selected evaluation contractor will harmonize and streamline these when collapsing the program-specific research topics and methods into one coherent work plan.

Exhibit 11: Management-by-Objective Framework for the Lighting Redesign and Equipment Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Direct engagement with supply-chain actors	Suggested KPI(s):	Direct engagement & communication logs					
		# of new actors being engaged with for the 1st time		10	25	5	5	5
		# of actors solicited for market intel & updates		10	35	35	35	35
		# of actors signing up as trade ally		5	5	1	1	1
05	Technical support for local supply-chain actors	Suggested KPI(s):	Program documentation & Direct engagement & comm. logs					
		# people attending classroom training		0	20	0	20	0
		# of 1-on-1 webinar or training sessions		5	10	10	5	5
		# of unsolicited calls for help		0	3	5	5	5
09	Trade events on conservation and lighting	Suggested KPI(s):	Program documentation					
		# of events with high level of visibility of inCharge brand		1	3	2	1	1
10	Supply-side actors develop projects	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s):	Direct engagement & comm. logs					
		# of new building manager being engaged with for the 1st time		10	10	5	5	5
		# of bldg managers solicited for market intel & updates		10	20	20	20	20
		# updates of web content		1	4	4	4	4
		# press releases		1	0	1	0	0
		# bill insert		1	1	1	1	1

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
13	Technical support for building managers	Suggested KPI(s): # of one-on-one webinar or training session with bldg managers # of unsolicited calls for help & % of calls that are successfully resolved	Direct engagement & comm. logs	2 0 n/a	5 2 100%	3 3 100%	3 2 100%	2 1 100%
14	Building owners/managers agree to initiate electricity efficiency projects	# of transactions in the lighting redesign incentive	Tracking System	Refer to the Program Design Report Exhibit 16, 17, 18, & 19				
15	Lighting redesign incentive	$ of incentive disbursement for lighting redesign	Tracking System	Refer to the Program Design Report Exhibits 20 & 21				
16	Electricity-efficient lighting opportunities are identified in the building	# of transactions in the lighting equipment incentive	Tracking System	Refer to the Program Design Report Exhibits 16, 17, 18, & 19				
17 & 18	Lighting equipment incentive and thus electricity-efficient lighting retrofit projects are implemented	$ of incentive disbursement for lighting equipment	Tracking System	Refer to the Program Design Report Exhibits 20 & 21				
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Tracking System	Refer to the Program Design Report Exhibits 22 & 23				
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed in under 10 business days	Tracking System	70%	80%	90%	95%	95%
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Direct engagement with supply-chain actors	No evaluation indicator	-			-		-
05	Technical support for local supply-chain actors	Suggested evaluation indicators: 1-to-10 scale, level of satisfaction with the training on average.	Supply-chain actors			7/10		n/a
09	Trade events on conservation, lighting and/or HVAC	Suggested evaluation indicators: % of market who can recall having seen inCharge at events	Participants, non-participants and supply-chain actors			60%		80%

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
10	Supply-side actors will actively seek to develop projects	Suggested indicator(s): % supply-chain actors who know the program	Supply-chain actors			90%		100%
		% of supply-chain actors who recommend the program to their customers				60%		80%
		% of relevant supply-side actors mapped out contributed to at least one transaction	Tracking system			30%		60%
		% of building manager who recall their provider telling them about program	Participants & non-participants			40%		
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction	Tracking system			40%		60%
		% of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants			70%		
13	Technical support for building managers	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the training on average.	Building managers (participants & non-part.)			7/10		
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
15	Lighting redesign incentive	Suggested indicator(s): % of participants who agree that the lighting redesign incentive got them to do a more sophisticated retrofit of their lighting system then they would have otherwise	Participants			60%		60%
		% of participating suppliers who confirm the above	Supply-chain actors			60%		60%
16	Electricity-efficient lighting opportunities are identified in the building	No evaluation indicator	-			-		-
17	Lighting equipment incentive	Suggested indicator(s): % of participants who agree that the incentive got them to install the energy efficient equipment in part or in full	Participants			60%		60%
		% of suppliers who agree that the incentive got their client to pursue with the install energy efficient equipment rather than the base in part or in full	Supply-chain actors			60%		60%
18	Electricity-efficient lighting retrofit projects are implemented	No evaluation indicator	-			-		-

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
19	The electricity-efficient lighting retrofit projects will yield long-term electricity and demand savings.	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants			7/10		7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the lighting quality	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy				8/10		8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service Lighting Redesign and Equipment Incentive. No additional questions are needed.

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service Lighting Redesign and Equipment Incentive* have implications on the evaluation methods being employed:

- No savings are attributed to the redesign incentive; savings will be attributed only when the participants actually implement the projects and file a final incentive claim.
- The projects that will be partially financed by the Utilities through the program elements are “custom” projects. Participants and their service providers will provide an estimate of the savings – based on engineering calculations, no measurement required – this estimate will be verified by the program administrator and input in the tracking system as is. Thus, there will be a specific impact for each project. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on “archetype projects”; those are not going to be used as part of ex-post evaluation.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis will not be an option.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: lighting designers (population≈2), electrical/lighting

distributors (p=2), electrical contractors (p≈26), property managers (p≈8 large, ≈32 small) and the Yukon Energy Solutions Center.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the forms and tools (job aids) provided to participants and supply-chain actors to estimate the savings for each projects and review of the procedures to validate the savings as part of regular program operations.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Quality assurance of a sample of projects selected thorough all the transactions during the 5-year program operation window to establish the actual realized savings for each project in the sample, and ultimately establish the realization ratio for all of the population of projects.
    - It is assumed that manufacturer estimates of the demand (W) for each lamp/fixture as provided in the equipment specification sheets will not have to be measured.
    - Evaluators will be asked to spend more effort validating the running time estimates because this is where most of the inaccuracies will reside; either through research and scans of relevant evaluation reports thorough North America, surveying with the participants, or actual running time measurements.
    - The sample size will be established by the evaluators in order to achieve a level of precision on the realization ratio of ±15% with a one-tailed confidence interval of 90%. Evaluators are suggested to stratify the population by project impact and use a differentiated sampling approach for each stratum in order to maximize value of impact evaluation.
- Review of site visit reports generated by the administration staff to estimate installation/removal rates and uncover issues related with persistence of the savings and the alike.
- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.2 General Service High Efficiency Refrigeration Program

4.2.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers who retrofit their refrigeration systems and/or install refrigeration controls. This will be a custom incentive for equipment and installation, i.e. it will be determined using a dollar per kilowatt-hour rate for each kilowatt-hour

of savings realized annually as compared with the pre-retrofit consumption and demand level. In addition to the incentive, the Utilities will provide extensive refrigeration-specific technical assistance to identify the opportunities, to develop the projects, to manage the construction works, and to measure and monitor the performance of the projects. It is expected that this program element will aim at hockey and curling arenas and grocery stores in particular.

Eligible Measures

The proposed incentive levels and archetype refrigeration projects are presented in Exhibit 12 and Exhibit 13.

Exhibit 12: Archetype High Efficiency Refrigeration Projects – Custom Incentive for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM98	Typical Low-Cost No-Cost Refrigeration Project - Food	6.55 kWh/ft2	.00074 kW/ft2	95%	$1.73/ft2	10.0 yr	$1.31/ft2	30,000 ft2
ECM99	Typical Deep Retrofit Refrigeration Project - Food	13.48 kWh/ft2	.00153 kW/ft2	95%	$5.87/ft2	10.0 yr	$2.70/ft2	30,000 ft2

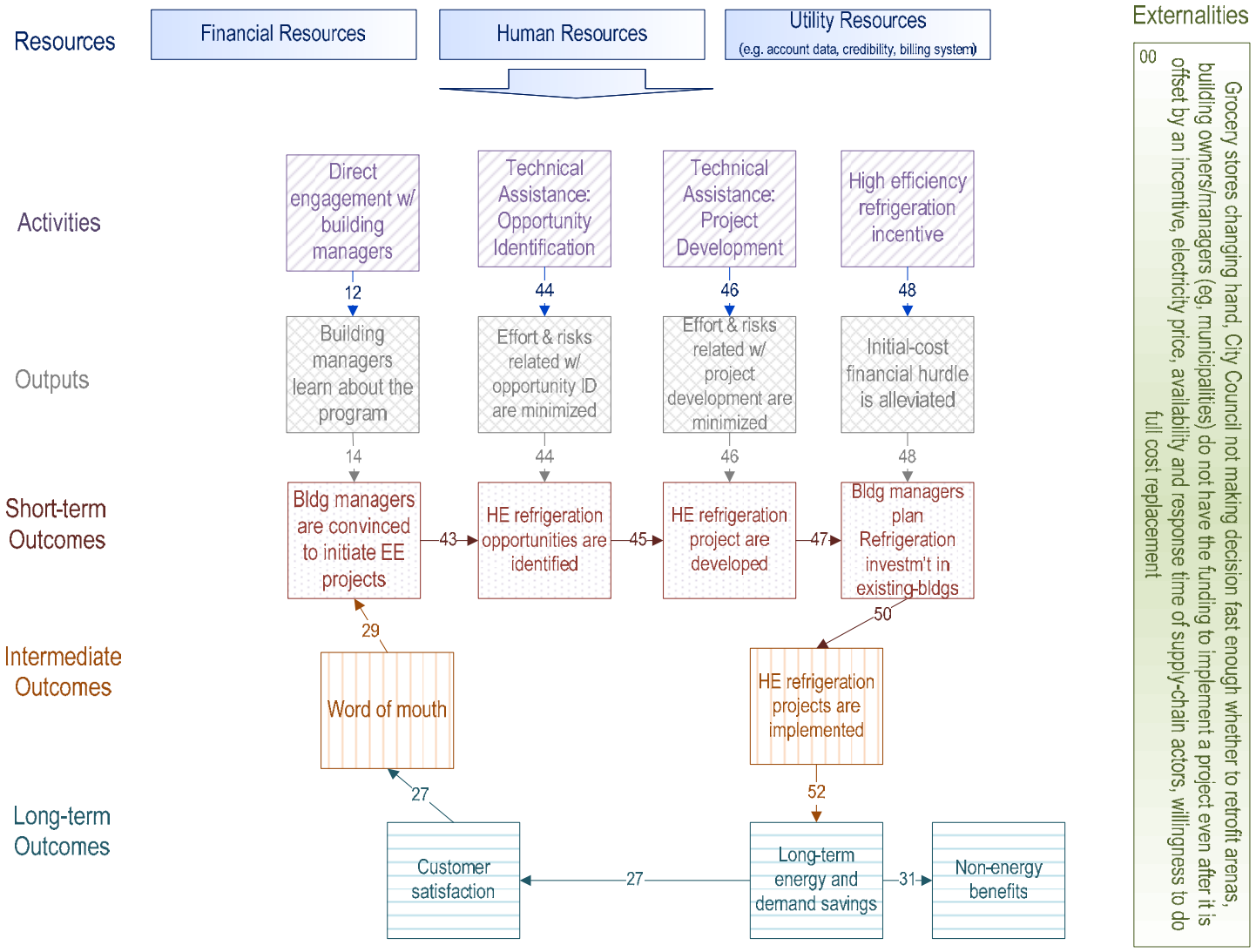
Exhibit 13: Archetype High Efficiency Refrigeration Projects – Custom Incentive for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM1002	Typical Refrigeration Project - Ice Rink	2.49 kWh/ft2	.00034 kW/ft2	95%	$0.72/ft2	20.0 yr	$0.40/ft2	25,000 ft2

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 14: Logic Model for the General Service High Efficiency Refrigeration Element



Link #	Narrative
00	Externalities: The program effectiveness and impact will be influenced by the following externalities: grocery store ownership changes, slow decision-making on the part of City Council regarding whether or not to retrofit arenas, a lack of funding for building owners/managers (e.g., municipalities) to implement a project even after it is offset by an incentive, the price of electricity, the availability and response time of supply-chain actors, and the willingness to do a full cost replacement.
12	Direct engagement with supply-chain actors. The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings, and through public relations activities like press releases sent to the local newspapers and radio stations, web content and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities.

Link #	Narrative
43	Building owners/managers are offered the free services of energy engineers representing the Utilities to assess their refrigeration system to identify efficiency opportunities. They participate because their risk exposure and level of effort are minimized.
44	The Utilities provide technical assistance to the building owners/managers in the form of an assessment of the refrigeration system to identify energy efficiency opportunities. As a result, high efficiency refrigeration opportunities are identified. It is assumed that the Utilities are offering services NOT being offered for profit by other market actors because the target market niche is too small to be lucrative. It is not displacing or blocking free-market mechanisms (i.e. not blocking an existing mechanism or mechanism in the making).
45	After the high efficiency refrigeration opportunities are identified, the participant is offered more support to develop the project. The participant is asked to make a commitment. If the resulting project is a cost-effective investment, the participant agrees to carry on and implement the project. Otherwise, the participant will have to pay part of the cost of the technical assistance. The participant accepts because the level of risk he/she is asked to take is fair.
46	The Utilities provide technical assistance to develop the high efficiency refrigeration project in the form of a feasibility study and/or an investment-grade audit. If the participant implements the proposed design, the feasibility study will be free of charge.
47	The participants are presented with investment- and implementation-ready high efficiency refrigeration projects.
48	The Utilities will pay an incentive to participants who implement the high efficiency refrigeration projects that are identified. The incentive will alleviate the initial-cost hurdle of the high-efficiency refrigeration retrofit projects.
50	Because high-efficiency projects will have been subsequently identified and then developed by the Utilities, and because the Utilities will alleviate the initial-cost hurdle, high-efficiency refrigeration retrofit projects will be implemented.
52	The high-efficiency refrigeration retrofit projects will yield long-term electricity and demand savings.
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry, perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits and/or maintain the benefits they used to have with baseline systems. For example, the Utilities will seek to ensure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and increase property value.

4.2.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 14 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 15. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 15 are provided in Section 4.1.2.

Exhibit 15: Management-by-Objective Framework for the General Service High Efficiency Refrigeration Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building manager being engaged with for the 1st time # of bldg managers solicited for market intel & updates	Direct engagement & comm. logs	10 10	- 10	- 10	10 10	- 10
14, 43 & 44	Building owners/managers are offered free energy engineering services to identify opportunities	Suggested KPI(s): # opportunity identification studies	Program documentation	0	10	0	10	0
45 & 46	Building owners/managers are offered support to develop the project	Suggested KPI(s): # feasibility studies	Program documentation	0	3	3	3	3
47, 48 & 50	High efficiency refrigeration incentive and thus electricity-efficient refrigeration retrofit projects are implemented[11]	$ of incentive disbursement for HE refrigeration	Program documentation	$0K *w/gov* $0	$0K $0	$122K $132K	$0K $0K	$122K $132K
52	The electricity-efficient refrigeration retrofit projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Program documentation	Refer to the Program Design Report Exhibits 35 & 36				
27	Building owners/managers will be satisfied by the projects that they implemented	No associated tracked KPIs	-	-	-	-	-	-
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction % of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Project documentation Participants & non-participants			40% 70%		60%

[11] Refer to the Program Design Report Exhibits 33 & 34

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
43, 44, 45, & 46	Building owners/managers are offered free energy engineering services to identify opportunities	% of participants who agree that the technical assistance got them to do a more sophisticated retrofit of their refrigeration system then they would have otherwise	Participants			60%		60%
47, 48 & 50	High efficiency refrigeration incentive and thus electricity-efficient refrigeration retrofit projects are implemented	% of participants who agree that the incentive got them to install the energy efficient equipment in part or in full	Participants			60%		60%
52	The electricity-efficient refrigeration retrofit projects will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-	-	-	-	-	-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants			7/10		7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants	Participants in any GS program elements			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the refrigeration quality	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy				8/10		8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service High Efficiency Refrigeration Program. In addition, the following question should be explored:

- How effective was the technical assistance at supporting prospective participants in making a decision with regard to energy efficiency projects?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service High-Efficiency Refrigeration Incentive* have implications on the evaluation methods being employed:

- Relatively few projects are anticipated (5 to 10), therefore transactional infrastructure will be basic and documentation will be on a project-by-project basis.
- No savings are attributed to the technical assistance phases of the project; savings will be attributed only when the participants actually implement the projects.
- An aggregate of the M&V results from the technical assistance phases of each project can be fed into the program-level evaluation.
- Participants and their service providers will provide an estimate of the savings – based on engineering calculations, no measurement required – this estimate will be verified and documented by the program administrator. Thus, there will be a specific impact for each project. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on "archetype projects"; those are not going to be used as part of ex-post evaluation.
- These projects are planned to occur in two waves: a first wave is planned to start around Y2-Q2, construction is to end on Y3-Q3, and the post-retrofit measurement period – expected to last for one year – is to end around Y4-Q3. The second wave will start on Y4-Q2 then follow a similar schedule. The completion of the M&V work for that second wave falls outside of the program window.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: store managers (population≈4); hockey/curling arena operators (p≈9); refrigeration contractors (p≈3); and the high-efficiency refrigeration consultant. Based on the results of the first half of the program period, the second half of the program period may involve: convenience stores, small grocery stores, and restaurants (p≈35).

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the technical assistance reports provided to participants to assess soundness of calculations and the proposed solutions, and effectiveness of the documents produced at supporting prospective participants in making a decision with regard to energy efficiency projects.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact of this program element will be evaluated based on the aggregated results of all of the project-level M&V reports completed as part of technical assistance components of the program. The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of

utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days. Please refer to Section 3.2 for additional details.

- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.

- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.3 General Service ENERGY STAR Computer Incentive

4.3.1 Program Description Summary

The Utilities will pay an incentive to companies and organizations to have their computer equipment replaced with ENERGY STAR computer equipment.

A prescriptive incentive approach will be as follows: the Utilities will pay a flat amount of money per unit to owners/managers when computers and computer equipment from a prescriptive list of eligible products are purchased.

Equipment eligibility is tracked using a prescriptive list, so a pre-approval step is not necessary. The participation process is therefore very straightforward: the participant will submit a simple application form and provide backup documentation (e.g. invoices) to receive the incentive payment.

Eligible Measures

The proposed incentive level and archetype projects for the ENERGY STAR computer incentive are presented in Exhibit 16 and Exhibit 17.

Exhibit 16: Prescriptive List of ENERGY STAR Computer Conservation Measures for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM101	ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	95%	$0.00/unit	4.0 yr	$30.00/unit
ECM102	ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	95%	$0.00/unit	4.0 yr	$10.00/unit

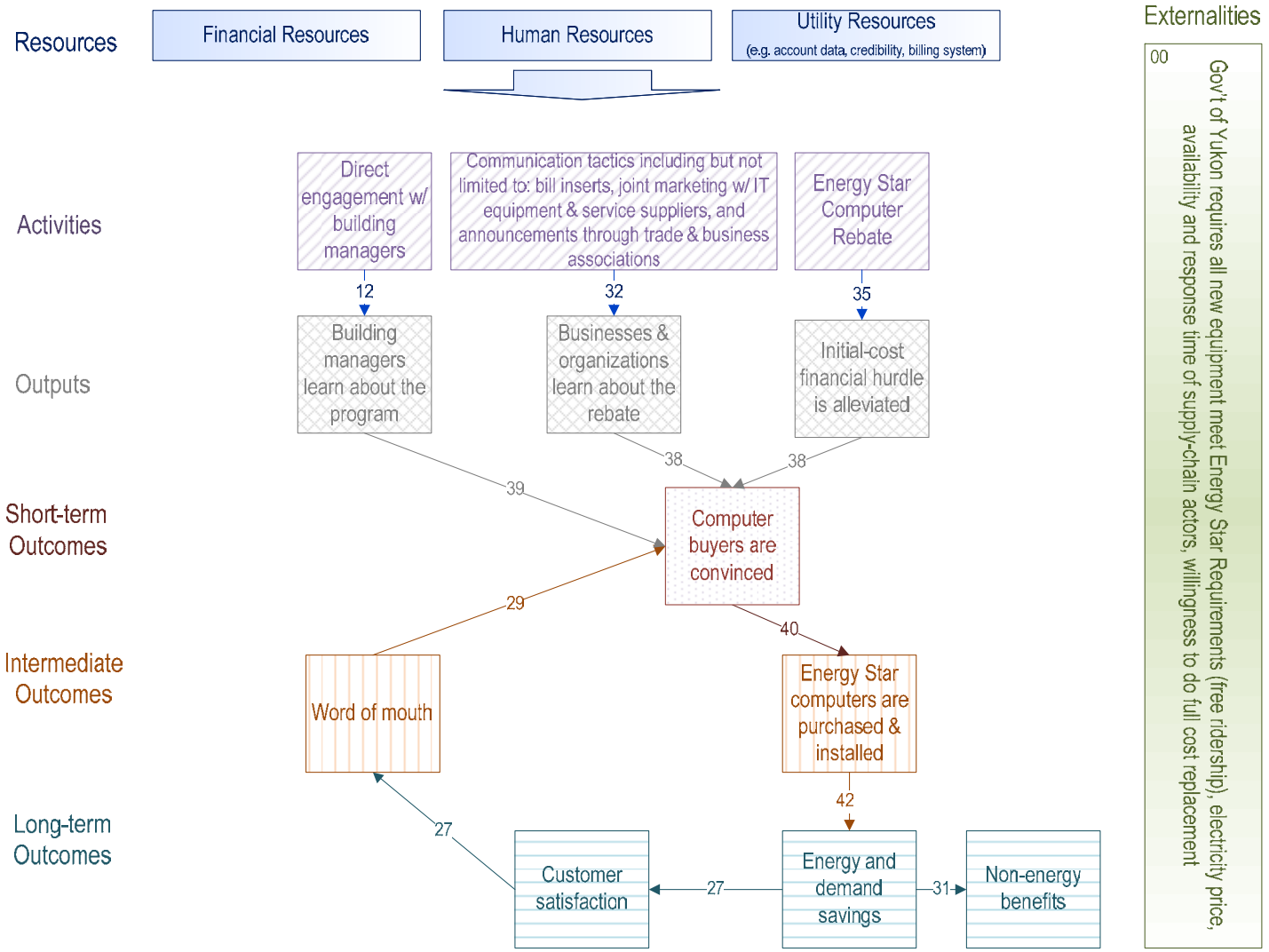
Exhibit 17: Prescriptive List of ENERGY STAR Computer Conservation Measures for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM1012	Gov. ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	55%	$0.00/unit	4.0 yr	$18.00/unit
ECM1022	Gov. ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	55%	$0.00/unit	4.0 yr	$6.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 18: Logic Model for the General Service ENERGY STAR Computer Element



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: the Gov't of Yukon's requirement that all new equipment meets ENERGY STAR standards (free ridership), the price of electricity, the availability and response time of supply-chain actors, and the willingness to do full cost replacements.
12	The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program. Some building owners/managers also make IT equipment purchase decisions.
32	The Utilities carry out many tactics to inform computer buyers at businesses and organizations based in the Yukon. As a result, the computer buyers will learn about the incentive offering.
35	The Utilities will pay an incentive to computer buyers in exchange for the purchase of an ENERGY STAR Computer. The incentive will alleviate the initial-cost hurdle of the ENERGY STAR Computer and will be a convincing selling point.

Link #	Narrative
38	Because computer buyers will know about the offering and because they are offered a rebate designed to influence them, they will buy ENERGY STAR computers.
40	ENERGY STAR computers are purchased instead of standard computers.
42	The ENERGY STAR computers will yield electricity and demand savings during their 4-year lifetime.
27	Participants will be satisfied with the ENERGY STAR computer that they purchased. They will relay their experiences to other computer buyers in the Yukon, generating word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause computer buyers to buy more ENERGY STAR computers.
31	It is assumed that the staff using ENERGY STAR computers will have the same user-experience as with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems turn on and off as fast as non-ENERGY STAR computers, and that their processors are as fast, etc.

4.3.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 10 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 19. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 19 are provided in Section 4.1.2.

Exhibit 19: Management-by-Objective Framework for the General Service ENERGY STAR Computer Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building managers being engaged with for the 1st time	Direct engagement & communication logs	10	10	5	-	-
		# of building managers contacted with program intel & updates		10	20	20	-	-
32	Utilities carry out many communication tactics to inform businesses & organizations about the rebate	# updates of web content	Tracking System	1	4	4	-	-
		# press releases		1	0	1	-	-
		# joint marketing w/IT equip suppliers		1	1	1	-	-
		# bill insert		1	1	1	-	-
		# email blasts		0	2	4	-	-
35 & 40	Participants receive a rebate[12]	$ of incentive disbursement for ENERGY STAR computers/monitors	Tracking System	$2K	$10K	$17K	-	-
				w/gov: $6K	$35K	$57K	-	-

[12] Refer to the Program Design Report Exhibits 45 & 46

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
38 & 39	ENERGY STAR computers are purchased & installed[13]	Suggested KPI(s): # of rebates claimed + stipulated 30% "spillover"[14]	Tracking System	96 *w/gov:* 386	612 2449	999 3996	- -	- -
42	The ENERGY STAR computer installations will yield electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand		Refer to the Program Design Report Exhibits 47 & 48				
27	Participants will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in under 10 days		70%	80%	90%	-	-
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-

Part B -- To Be Visited, Checked and Reported On by Evaluators			Baseline ↓	Process Eval. ↓		Impact Eval. ↓	
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction	Tracking system			40%		
32	Utilities carry out many communication tactics to inform businesses & organizations about the rebate	Suggested indicator(s): % of building managers who can recall one of the following: bill inserts, web content, or contact from IT suppliers	Participants & non-participants			70%		
35 & 40	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate got them to purchase the energy efficient products	Participants			60%		
38 & 39	ENERGY STAR computers are purchased & installed	No evaluation indicator	-			-		-
42	The ENERGY STAR computer installations will yield electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
27	Participants will be satisfied by the products that they bought	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program 1-to-10 scale, level of satisfaction with their energy efficient products	Participants Participants			8/10 7/10		
29	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		

[13] Refer to the Program Design Report Exhibits 43 & 44 (they do not include the estimated spillover)
[14] This is one way to extrapolate the total number of shoppers influenced by the program (including those that purchased and installed rebate-eligible products without claiming a rebate)

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
31	Non-energy benefits	Suggested indicator(s): % of participants who believe that performance of the ENERGY STAR computer is equal to that of a standard computer % of participants who believe that buying an ENERGY STAR computer will be important or very important to them next time they buy a computer, even in the absence of a rebate program.	Participants			90% 70%		

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service ENERGY STAR Computer Incentive without nuance. No additional questions are needed.

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service ENERGY STAR Computer Incentive* have implications on the evaluation methods employed:

- Participants will receive a flat incentive per unit after they purchase computers and computer equipment from a prescriptive list of eligible products. Deemed savings and the use of a TRM are recommended.
- The ENERGY STAR computer incentive will close in Q4 of Y3.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis or whole-building M&V will not be an option.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: IT equipment suppliers and retail stores (p≈20), property managers (p≈8 large, ≈32 small) and the Yukon Energy Solutions Centre.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Primarily, the impact will be computed based on the number of rebate transactions, deemed savings and the content of the TRM. The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.

- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.4 General Service New Construction Incentive

4.4.1 Program Description Summary

The Utilities will pay an incentive to building owners/managers for high performance new buildings. The incentive will have two paths: a prescriptive path for small buildings and a custom path for large buildings. The prescriptive incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard. The custom incentive will be determined using a dollar per kilowatt-hour of annual savings rate for each kilowatt-hour of savings realized above a minimum level. Savings will be determined through building modeling.

Eligible Measures

The proposed incentive level as well as archetype projects are presented in Exhibit 20 and in Exhibit 21.

Exhibit 20: Archetype Electricity-Efficient Non-Government New Construction Projects

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM89	Typical High-Performance New Building - 25% Better	5.93 kWh/ft2	.00135 kW/ft2	95%	$2.00/ft2	20.0 yr	$1.50/ft2	11,759 ft2
ECM90	Typical High-Performance New Building - 40% Better	9.49 kWh/ft2	.00217 kW/ft2	95%	$6.00/ft2	20.0 yr	$4.00/ft2	11,759 ft2

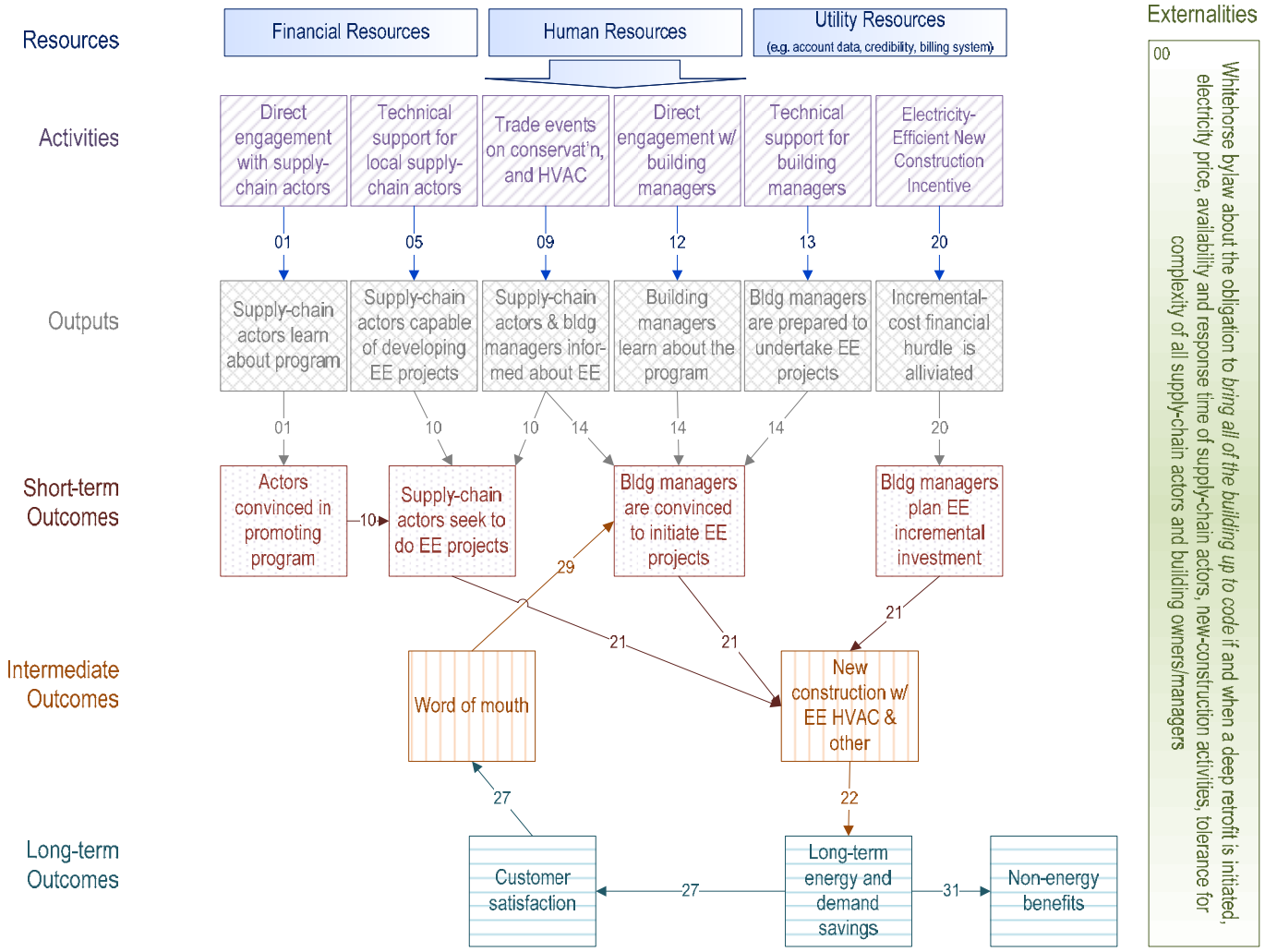
Exhibit 21: Archetype Electricity-Efficient Government New Construction Projects

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive	Size of Archetype Building
ECM892	Gov. Typical High-Performance New Building - 25% Better	5.93 kWh/ft2	.00135 kW/ft2	95%	$2.00/ft2	20.0 yr	$0.90/ft2	26,209 ft2
ECM902	Gov. Typical High-Performance New Building - 40% Better	9.49 kWh/ft2	.00217 kW/ft2	95%	$6.00/ft2	20.0 yr	$2.40/ft2	26,209 ft2

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 22: Logic Model for the General Service New Construction Incentive



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: Whitehorse bylaws on the obligation to bring all of the buildings up to code if and when deep retrofits are initiated, the price of electricity, the availability and response time of supply-chain actors, new-construction activities, and tolerance for complexity of all supply-chain actors and building owners/managers. The program administrator should monitor these externalities and adapt the implementation approach as necessary.
01	The Utilities will carry out direct engagement with electrical distributors, lighting designers, electrical contractors, as well as with HVAC contractors, HVAC designers, control designers and architects through emails, phone calls and in-person meetings. The Utilities will present their incentive offerings and engage with supply-chain actors so that they promote them.

Link #	Narrative
05	The Utilities will offer technical support to the supply-chain actors in two different forms: (1) hands-on training on the program tools, forms and procedures; on advanced electricity efficiency lighting design; and on the business aspects of electricity efficiency: energy audits, business cases, energy performance contracting, and electricity efficiency financing. (2) The Utilities will act as a broker to procure technical expertise from highly specialized lighting experts recruited throughout North America upon request from the local actors. In addition, the Utilities will disseminate information on recommended lighting equipment (brand-neutral, to the extent possible) in the form of printed brochures, newsletters or web content.
09	The Utilities propose to support any form of trade organizations or trade events by sponsoring and attending trade events that gather local building owners/managers and/or supply-chain actors. The Utilities intend to strengthen or create platforms that allow local energy conservation practitioners to present their success stories, and share their lessons learned.
10	Supply-side actors will actively seek to develop projects because they were engaged with by the Utilities, because they were trained and are capable of offering electricity-efficiency services, and because they were provided with networking opportunities with potential clients (building owners/managers) at trade events.
12	The Utilities will carry out direct engagement with building owners/managers through emails, phone calls and in-person meetings; and through public relations activities like press releases sent to the local newspapers and radio, web content, and joint events with the Whitehorse Chamber of Commerce. The Utilities will present their incentive offerings and make the owners/managers aware of the benefits so that they participate in the program.
13	The Utilities will offer customized technical support to building owners/managers to help them to initiate projects. The Utilities could include support to plan investment in assets, and to identify in which buildings to develop projects; support to make optimal decisions on implementation and procurement approach, and support before and during the tendering of project design services, particularly if the procurement approach is energy performance contracting (EPC).
14	Building owners/managers agree to initiate electricity efficiency projects because they were informed about the program components by the Utilities, because they were provided with technical support to decide where to start and how to do it, and because they networked with supply-side actors, perhaps at the trade events supported by the Utilities.
20	The Utilities will pay an incentive to new building owners/managers for electricity-efficient new buildings construction. The incentive will alleviate the initial-cost hurdle of the construction of electricity-efficient buildings. The incentive will be performance-based and be paid for buildings that are more electricity efficiency than the combination of the 2011 National Energy Code of Canada for Building and the City of Whitehorse's Building and Plumbing Bylaw.
21	Electricity-efficient new buildings constructions are implemented because the supply-chain actors were seeking to work on electricity-efficient new construction projects, and because the initial-cost hurdle of the construction of electricity-efficient buildings was alleviated.
22	The electricity-efficient new buildings will yield long-term electricity and demand savings.
27	Building owners/managers will be satisfied by the projects that they implemented. They will tell other people in the building industry; perhaps at the trade events supported by the utilities. This will generate word-of-mouth advertisement.
29	With time, word-of-mouth will become an important information channel that will cause building owners/managers and supply-chain actors to implement more projects.
31	It is assumed that owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. For example, the Utilities will seek to make sure that participants perceive that their new systems are more comfortable, are less costly to maintain, have higher tenant satisfaction and retention, generate fewer complaints, and have increased property value.

4.4.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 22 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 23. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 23 are provided in Section 4.1.2.

Exhibit 23: Management-by-Objective Framework for the General Service New Construction Incentive

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Direct engagement with supply-chain actors	Suggested KPI(s): # of new actors being engaged with for the 1st time	Direct engagement & communication logs	6	12	-	-	-
		# of actors solicited for market intel & updates		6	18	18	18	18
		# of actors signing up as trade ally		5	5	1	1	1
05	Technical support for local supply-chain actors	Suggested KPI(s): # people attending classroom training	Program documentation & Direct engagement & comm. logs	0	10	0	10	0
09	Trade events on conservation and HVAC	Suggested KPI(s): # of events with high level of visibility of inCharge	Program documentation	1	1	1	1	1
10	Supply-side actors develop projects	No associated tracked KPIs	-	-	-	-	-	-
12	Direct engagement with building managers	Suggested KPI(s): # of new building manager being engaged with for the 1st time	Direct engagement & comm. logs	10	10	5	5	5
		# of bldg managers solicited for market intel & updates		10	20	20	20	20
		# updates of web content		1	4	4	4	4
		# press releases		1	0	1	0	0
		# bill insert		1	1	1	1	1
13	Technical support for building managers	Suggested KPI(s): # of one-on-one webinar or training session with bldg managers	Direct engagement & comm. logs	2	5	3	3	2
		# of unsolicited calls for help & % of calls that are successfully resolved		0 n/a	2 100%	3 100%	2 100%	1 100%

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
14	Building owners/managers agree to initiate electricity efficiency projects	# of transactions in the new construction incentive	Tracking System	Refer to the Program Design Report Exhibits 56 & 57				
20 & 21	New construction incentive and thus electricity-efficient projects are implemented[15]	$ of incentive disbursement for new construction	Tracking System	$0 *w/gov* $0K	$4K $6K	$19K $25K	$30K $39K	$34K $45K
22	The electricity-efficient projects will yield long-term electricity and demand savings	kWh of avoided electricity consumption kW of avoided coincident electricity demand	Tracking System	Refer to the Program Design Report Exhibits 60 & 61				
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed below 10 business days	Tracking System	70%	80%	90%	95%	95%
29	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
31	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Suggested evaluation indicators: Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Direct engagement with supply-chain actors	No evaluation indicator	-			-		-
05	Technical support for local supply-chain actors	Suggested evaluation indicators: 1-to-10 scale, level of satisfaction with the training on average.	Supply-chain actors			7/10		n/a
09	Trade events on conservation and HVAC	Suggested evaluation indicators: % of market who can recall having seen inCharge at events	Participants, non-participants and supply-chain actors			60%		80%
10	Supply-side actors will actively seek to develop projects	Suggested indicator(s): % supply-chain actors who know the program % of supply-chain actors who recommend the program to their customers % of relevant supply-side actors mapped out contributed to at least one transaction % of building manager who recall their provider telling them about program	Supply-chain actors Tracking system Participants & non-participants			90% 60% 30% 40%		100% 80% 60%
12	Direct engagement with building managers	Suggested indicator(s): % of relevant building managers who have had at least one transaction % of building managers who can recall one of the following: bill inserts, web content, or inCharge in the news	Tracking system Participants & non-participants			40% 70%		60%

[15] Refer to the Program Design Report Exhibits 58 & 59

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
13	Technical support for building managers	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the training on average.	Building managers (participants & non-part.)			7/10		
14	Building owners/managers agree to initiate electricity efficiency projects	Suggested indicator(s): % of participants who agree that utility technical assistance got them to implement project in full of in part	Participants			60%		60%
20	New construction incentive	Suggested indicator(s): % of participants who agree that the incentive got them to work on an energy efficient building design in part or in full % of suppliers who agree that the incentive got their client to increase the energy performance of their building	Participants Supply-chain actors			60% 60%		60% 60%
21	Electricity-efficient projects are implemented	No evaluation indicator	-	-	-	-	-	-
22	The electricity-efficient projects will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-	-	-	-	-	-
27	Building owners/managers will be satisfied by the projects that they implemented	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall program 1-to-10 scale, level of satisfaction with their energy efficient equipment	Participants Participants			8/10 7/10		8/10 7/10
29	Word-of-mouth will become an important information channel	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		60% 30%
31	Owners/managers will perceive new non-energy benefits; and/or the maintenance of benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the lighting quality 1-to-10 scale, level of satisfaction with the operations, ease of maintenance, & life expectancy	Participants			9/10 8/10		9/10 8/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the General Service New Construction Incentive. In addition, the following questions will be explored:

- Is the baseline building standard for this program sound, and should the baseline be changed mid-course?
- Is the market ready for a more stringent building code?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *General Service New Construction Incentive* have implications on the evaluation methods employed:

- Under the prescriptive path, the incentive will be determined using a dollar-per-square foot rate if the building complies with a certain standard. The standard will be designed to be slightly more stringent than the Model National Energy Building Code minus 25% (MNEBC -25%) and the City of Whitehorse's Building and Plumbing Bylaw.
- Under the custom-incentive path (or performance path), the custom incentive will be determined using a dollar per kilowatt-hour of annual savings rate for each kilowatt-hour of savings that are realized above a minimum level. Savings will be determined through building energy modeling. The baseline and modeling requirements will be the same as those for the Canada Green Building Council's LEED building certification. Deemed savings and the use of a TRM are irrelevant. Impact and incentive cash flow projections were based on "archetype projects"; those are not going to be used as part of ex-post evaluation.
- The program performance was modeled before the launch using the archetype projects presented in Exhibit 20 and in Exhibit 21Exhibit 21. However, during program implementation, each transaction is treated as a custom project, with a specific level of electricity and demand savings, and a specific total incentive amount.
- This is an incentive for new building constructions, and since there are no "pre-build" utility bills or measurements, whole-building M&V is not applicable (Option C of the IPMVP).
- Calibrated building energy modeling might be practical (that is: Option D according to the IPMVP). The Utilities are working under the assumption that the number of transactions will not be large enough to justify an Option-D methodology; and regular building energy modeling will be sufficient. For the benefit of the readers: under the calibrated building energy modeling approach, building analysts adjust their project-scenario model ex post so that the model reflects early utility bills. Many changes that are uncovered then must also be applied to the base-case scenario. The resulting "calibrated" saving estimate is then considered to be more accurate. It is expected that the program element will involve or have implications on the following market actors and stakeholders: HVAC/control designers and contractors (p≈18), property managers (p≈8 large), architects (p≈3), and the Yukon Energy Solutions Centre.

Based on the above, the suggested process evaluation methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Literature review and jurisdictional scan to establish valid stipulated NTG ratios.
- Review of the forms and tools (job aids) provided to participants and supply-chain actors to estimate the savings for each projects and review of the procedures to validate the savings as part of regular program operations.

- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Quality assurance of a sample of projects selected thorough all the transactions during the 5-year program operation window to establish the actual realized savings for each project in the sample, and ultimately establish the realization ratio for all of the population of projects.
    - Verification will be based on “as-built” blueprints that shall be collected as part of program operations.
- Stipulated measure lifetime will be assumed to be 20 years and stipulated net-to-gross ratio will be assumed to be 95%. These stipulated values are to be validated by the evaluators during the finalization of the EM&V plan.
- New, updated and expanded literature review and jurisdictional scan to establish valid stipulated NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.5 Residential LED Lighting & Automotive Heater Timer Rebates

4.5.1 Program Description Summary

The Utilities will provide a flat incentive per unit to shoppers and housing developers after they purchase LED lighting lamps or fixtures or a timer for an automotive heater, car warmer and/or battery blanket selected from a prescriptive list of eligible products.

The Utilities will explore three possible rebate delivery mechanisms: (1) instant rebate at the point of purchase, (2) mail-in rebate, or (3) both. Instant-rebates are generally preferred by participants and will, therefore, be pursued first. However, the Utilities retain the option to complete a mail in rebate if market or regulatory conditions preclude from using instant rebates.

The Utilities retain the right to modulate the rebate though the same fiscal year to be able to react to market conditions and use marketing tactics to drive up the demand. In addition, the Utilities retain the right to update the incentive levels, the list of eligible products and the LED incentive budget on an annual basis.

Automotive heater timers gained a bad reputation in the Yukon because they reportedly failed. In order to address this, the Utilities envision applying the following tactics:

- The Utilities will start by promoting indoor automotive heater timers with the housing developers. Indoor timers are not subjected to cold weather and are therefore more reliable.
- The Utilities know that outdoor automotive heater timers are being promoted by utilities in Alaska. The Utilities intend to research the automotive heater timers that the Alaskan utilities are promoting, to test them in the Yukon. The Utilities will start promoting these automotive heater timers once the reliability issue is resolved.

Eligible Measures

The first list of prescriptive measures will include the items presented in Exhibit 24.

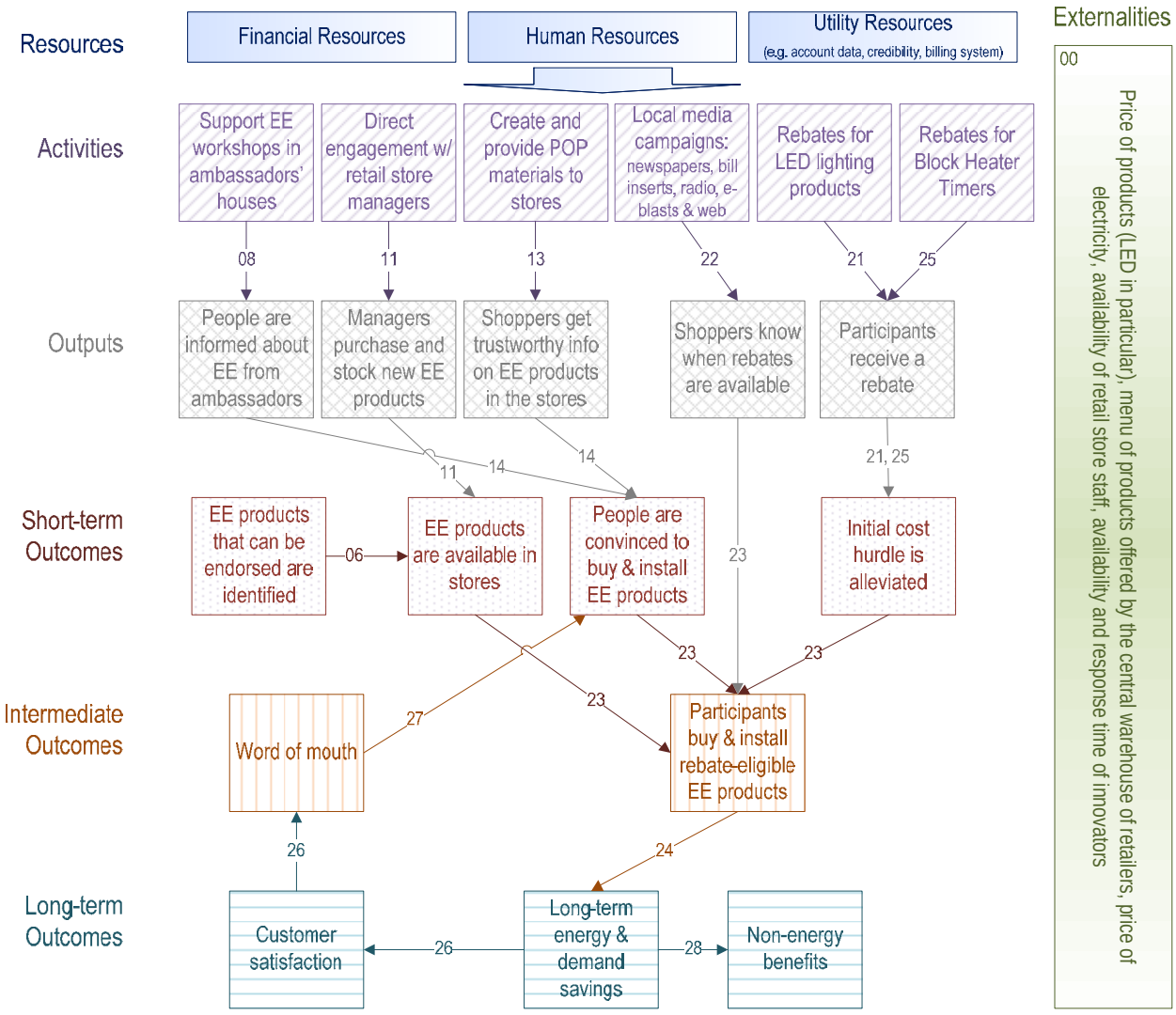
Exhibit 24: Prescriptive List of Residential LED Lighting and Automotive Heater Timer Energy Conservation Measures

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM151	Block Heater Timer	130 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$20.00/unit
ECM24	12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	110%	$44.00/unit	20.0 yr	$18.00/unit
ECM60	8W LED A19 Bulb	32.0 kWh/unit	0.011 kW/unit	110%	$30.00/unit	20.0 yr	$12.00/unit
ECM61	LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	110%	$20.00/unit	20.0 yr	$10.00/unit
ECM62	LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	110%	$51.00/unit	20.0 yr	$20.00/unit
ECM63	LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	110%	$43.00/unit	20.0 yr	$20.00/unit
ECM44	Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	80%	$25.00/unit	10.0 yr	$10.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 25: Logic Model for the Residential LED Lighting & Automotive Heater Timer Rebates



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, availability of retail store staff, availability and response time of innovators The program administrator should monitor these externalities and adapt the implementation approach based on them.
06	The consumer responses provided on the scorecards will be aggregated, analyzed and provided to the store managers. The Utilities will be able to endorse certain EE products because customer satisfaction will be good. The results will be presented to the retail store managers, and feed the communication and POP materials. It is expected that store managers will react by stocking more of these products and allocate more shelf space.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, automotive heater timers and innovative heating and DHW systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign starting in June of each year through local radio, local newspapers, co-op advertisement with retailers and in stores, email blast, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available. The marketing tactics used will create a sense of urgency and push Yukon shoppers to make the right purchase decision; it is expected to boost overall program uptake as compared a continuously available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (indoor or outdoor) from selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	It is assumed that shoppers will perceive new non-energy benefits; and/or the maintenance of benefits they used to h baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

4.5.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 25 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 26. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 26 are provided in Section 4.1.2.

Exhibit 26: Management-by-Objective Framework for the Residential LED Lighting and Automotive Heater Timer Rebates

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
06	Scorecard results will be analyzed and provided to store managers	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	10	5	3	2	0
		EE products that can be endorsed by the Utilities are reviewed and identified (Yes/No)		Yes	Yes	Yes	Yes	Yes
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	0	2	4	10	0
		# people attending workshops		8	8	8	8	-
11	Direct engagement with retail store managers	Suggested KPI(s): # of new store managers being engaged with for the 1st time	Direct engagement & communication logs	20	-	-	-	-
		# of store managers contacted with program intel & updates		20	20	20	20	20
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s): # stores with POP materials	Program documentation	5	10	10	10	10
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	Yes	Yes	Yes	Yes
14 & 23	Shoppers buy and install rebate-eligible products[16]	Suggested KPI(s): # of units claimed + estimated 30% "spillover"[17]	Tracking System	1019	4439	4491	4491	4491
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[18]	MWh of avoided lifetime electricity consumption	Estimate based on rebates processed + spillover	718	3149	3207	3207	3207
		MWh of avoided annual electricity consumption		36	199	368	537	705
		MW of avoided coincident electricity demand		13	71	131	191	252
21 & 25	Participants receive a rebate[19]	$ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	$12K	$51K	$52	$52K	$52K

[16] Refer to the Program Design Report Exhibit 70 (they do not include the estimated spillover)
[17] This is one way to extrapolate the total number of shoppers influenced by the program (including those that purchased and installed rebate-eligible products without claiming a rebate).
[18] Refer to the Program Design Report Exhibit 72
[19] Refer to the Program Design Report Exhibit 71

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
22	Shoppers learn about rebates through local media campaigns	# updates of web content # newspaper/radio advertisements # bill insert # email blasts	Tracking System	1 1 1 1	4 1 1 1	4 1 1 1	4 1 1 1	4 1 1 1
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	80%	90%	95%	95%
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
06	Scorecard results will be analyzed and provided to store managers	Suggested indicator(s): % store managers who agree that scorecards helped influence purchasing and/or shelf space decisions	Store managers			70%		70%
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
11	Direct engagement with retail store managers	Suggested indicator(s): % store managers who know the program % of store managers contributed to at least one transaction	Store managers Tracking system			100% 60%		100% 70%
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials % of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product	Shoppers and Participants			70% 50%		70% 50%
14 & 23	Shoppers buy and install rebate-eligible products	No evaluation indicator	-			-		-
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants			60%		60%
22	Shoppers learn about rebates through local media campaigns	Suggested indicator(s): % of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants			70%		

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s):						
		1-to-10 scale, level of satisfaction with the overall rebate program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient products	Participants			7/10		7/10
27	Word-of-mouth	Suggested indicator(s):						
		% heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
28	Non-energy benefits	Suggested indicator(s):	Participants					
		1-to-10 scale, level of satisfaction with the lighting/automotive heater timer quality				9/10		9/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential LED Lighting and Automotive Heater Timer Rebate. In addition, the following questions will be explored:

- How shoppers are influenced by the rebate, but do not ultimately redeem the rebate?
- Has the engagement with the retailers, including sharing the scorecards and the research performed on their behalf, influenced their habits (such as stocking, merchandizing, promotions, and adding new products) to sell more energy efficient products?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential LED Lighting and Automotive Heater Timer Rebates* have implications on the evaluation methods employed:

- Participants will receive a flat incentive per unit after they purchase LED lighting lamps or fixtures or a timer for an automotive heater timer, car warmer and/or battery blanket from a prescriptive list of eligible products. Deemed savings and the use of a TRM are recommended.
- It is unlikely that the savings per building will be above 10% of the total building electricity consumption; therefore utility billing analysis or whole-building M&V will not be an option.
- Shoppers who are influenced to purchase rebate-eligible products in many cases will not claim the rebate. Hence, the amount of rebate disbursements will not provide a complete indicator of the program impact.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: retail store managers (p≈20), landlords (p≈50),

shoppers (p≈20,000), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews with supply-chain actors, and phone or online surveys with participants and non-participants, but evaluators will be able to suggest an alternative approach if necessary. Mystery shoppers and retail intercepts might also be considered. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the point-of-purchase materials, scorecard feedback, and media campaign material to review their quality and quantity (refer to the KPIs specified in the MBO framework).
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Primarily, the impact will be computed based on the number of rebate transactions, deemed savings and the content of the TRM. The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.
- There is potential for claiming savings over and above the savings realized by those who will redeem the rebates: that is the savings resulting from incremental sales in LED lighting equipment and automotive heater timers from shoppers influenced by the program but who do not ultimately redeem the rebate. Evaluators refer to commonplace occurrence as ‘spillover’. The approach to estimating these savings involve the following:
  - Consult with the store managers during the finalization of the EM&V plan and confirm their commitment to provide sales data for rebate-eligible products during the 5-year DSM operations window. It is recommended to obtain a detailed commitment; agree on how and when the data will be available and what measures are going to be taken to ensure confidentiality.
  - If the evaluators are successful with the above, then the evaluators will lay out the method to estimate the savings based on the expected data in the final EM&V plan.
- For this program element only, because of the above, and if the evaluators are successful at securing the sales data, the evaluators might choose not to use stipulated NTG ratios. Instead, the evaluators will estimate the spillover ratio based on the sales data and use 1 + Spillover as NTG ratio.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.6 Residential Promotion of Low-Cost Energy Efficient Products

4.6.1 Program Description Summary

The Utilities will prepare and disseminate information on products that generate electricity savings but do not have a perceptible price increment as compared with the baseline equipment. The Utilities will disseminate information through point of purchase displays and brochures in retail stores, and through community engagement. Certain low-cost items will be provided by the Utilities to community volunteers to test and showcase: for example certain LED lamps, low-flow showerheads, faucet aerators, etc. The Utilities will give out a limited number of these items free of charge; volunteers will try them out, fill out a scorecard and send it back. The results will be fed back first to the store managers, and then to the consumers through point of purchase displays and brochures and through community engagement.

Eligible Measures

The preliminary list of low-cost EE products that the Utilities intend to promote includes the items presented in Exhibit 27.

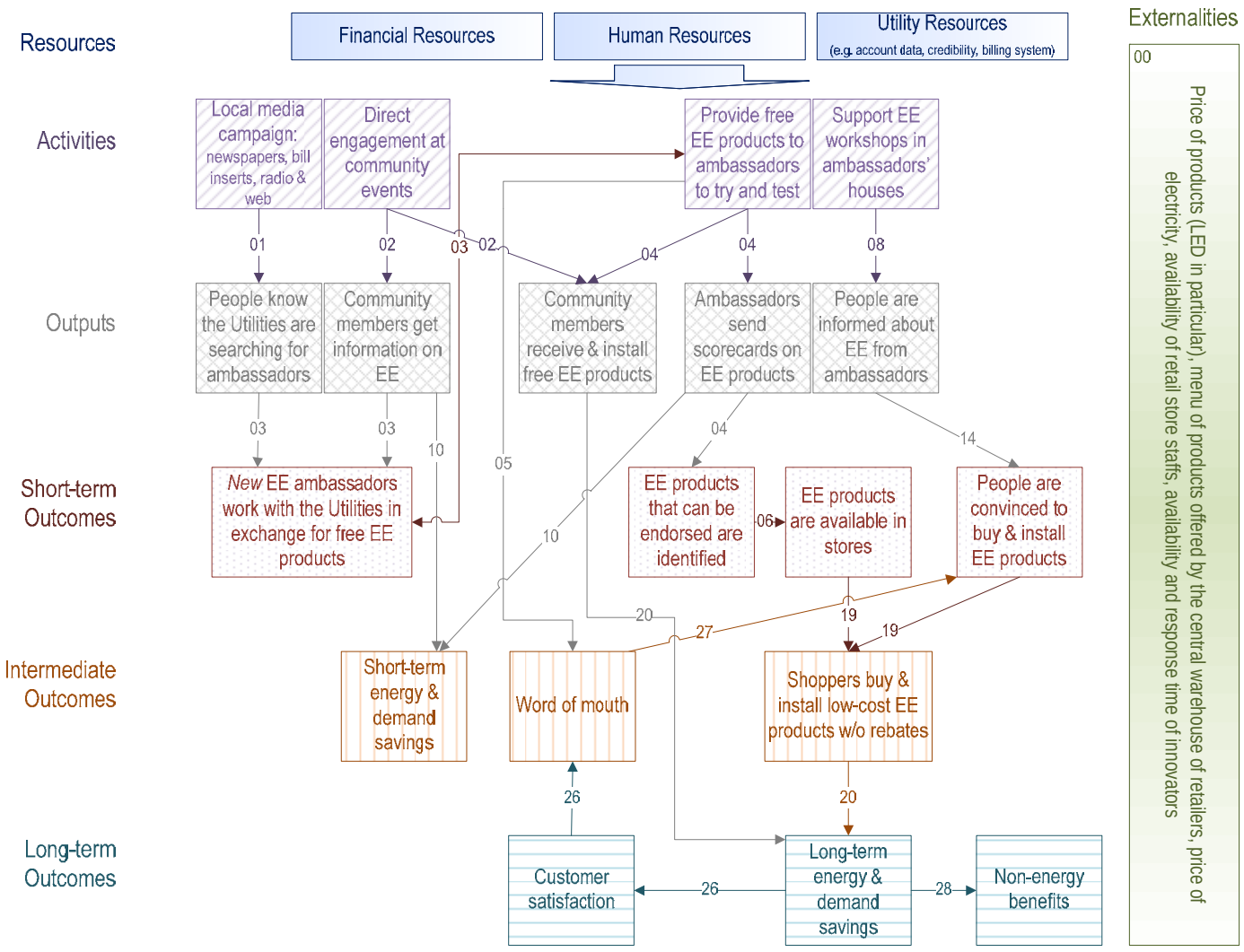
Exhibit 27: List of Energy Conservation Measures Based on Low-cost EE Products

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM242	Pilot 12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	100%	$44.00/unit	20.0 yr	$44.00/unit
ECM602	Pilot 8W LED A19 Bulb	32 kWh/unit	0.011 kW/unit	100%	$31.00/unit	20.0 yr	$31.00/unit
ECM612	Pilot LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	100%	$25.00/unit	20.0 yr	$25.00/unit
ECM622	Pilot LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	100%	$64.00/unit	20.0 yr	$64.00/unit
ECM632	Pilot LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	100%	$53.00/unit	20.0 yr	$53.00/unit
ECM442	Pilot Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	100%	$25.00/unit	10.0 yr	$25.00/unit
ECM092	Pilot Ultra Low-flow Showerheads	325.0 kWh/unit	0.116 kW/unit	100%	$16.01/unit	10.0 yr	$16.01/unit
ECM112	Pilot Smart, Surge Protected Power Bars for PCs and TVs	67.8 kWh/unit	0.024 kW/unit	100%	$50.00/unit	10.0 yr	$50.00/unit
ECM182	Pilot DHW Tank Insulation	62.0 kWh/unit	0.022 kW/unit	100%	$37.58/unit	14.0 yr	$37.58/unit
ECM202	Pilot DHW Pipe Insulation	34.0 kWh/unit	0.012 kW/unit	100%	$0.79/unit	15.0 yr	$0.79/unit
ECM482	Pilot Motion Detectors - Indoor and Outdoor	66.0 kWh/unit	0.024 kW/unit	100%	$22.94/unit	10.0 yr	$22.94/unit
ECM152	Pilot Auto Heater Timers	129.8 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$37.50/unit
ECM142	Pilot Prog. Thermostats (Central)	827.0 kWh/unit	0.295 kW/unit	100%	$62.50/unit	11.0 yr	$62.50/unit
ECM212	Pilot Prog. Thermostats	826.0 kWh/unit	0.295 kW/unit	100%	$285.43/unit	11.0 yr	$285.43/unit
ECM062	Pilot E-Star TVs	69.0 kWh/unit	0.025 kW/unit	100%	$1,125.00/unit	10.0 yr	$1,125.00/unit
ECM082	Pilot ESTAR Printers and Fax	31.7 kWh/unit	0.011 kW/unit	100%	$200.00/unit	6.0 yr	$200/unit
ECM091	Ed. Ultra Low-flow Showerheads	325.0 kWh/unit	0.116 kW/unit	100%	$8.62/unit	10.0 yr	$0/unit
ECM111	Ed. Smart, Surge Protected Power Bars for PCs and TVs	68 kWh/unit	0.024 kW/unit	100%	$25.00/unit	10.0 yr	$0/unit
ECM181	Ed. DHW Tank Insulation	62 kWh/unit	0.022 kW/unit	100%	$37.58/unit	14.0 yr	$0/unit
ECM201	Ed. DHW Pipe Insulation	34.0 kWh/unit	0.012 kW/unit	100%	$0.79/unit	15.0 yr	$0.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 28: Logic Model for the Residential Low-Cost Energy Efficient Products



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, availability of retail store staff, availability and response time of innovators The program administrator should monitor these externalities and adapt the implementation approach based on them.
01	The Utilities will advertise their intention of building an EE community network through the local press, and applicable non-profit and community organizations. It is expected that this tactic will ease the development of the network.
02	The Utilities will carry out outreach activities in community events (eg. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; offer to new home buyers to pilot CCHPs, or GSHPs; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
03	The Utilities will build new relationships and an EE community network that the Utilities will be able to use to extend its communication and community direct engagement footprint.
04	The Utilities will have low-cost EE products tested through volunteers and/or the EE community network. The Utilities will give out a limited number of these items free of charge; the ambassadors will try them out, fill out a simple scorecard and send the scorecard back. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction in other program components such as the LED rebate component, the automotive heater timer rebate component and the low-cost EE product education component.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
06	The consumer responses provided on the scorecards will be aggregated, analyzed and provided to the store managers. The Utilities will be able to endorse certain EE products because customer satisfaction will be good. The results will be presented to the retail store managers, and feed the communication and POP materials. It is expected that store managers will react by stocking more of these products and allocate more shelf space.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, automotive heater timers and innovative heating systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products might have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	It is assumed that shoppers will perceive new non-energy benefits; and/or the maintenance of benefits they used to h baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

4.6.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 28 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 29. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 29 are provided in Section 4.1.2.

Exhibit 29: Management-by-Objective Framework for the Residential Promotion of Low-Cost Energy Efficient Products

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Utilities advertise their request for EE ambassadors	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 2 2 2	 1 1 1	 1 1 1	 1 1 1	 - - -
02	Utilities conduct outreach activities at community events[20]	Suggested KPI(s): # of events w/Program booth # of units of free products given away	Program documentation	 2 522	 4 627	 4 553	 4 532	 2 438
03	Utilities build an EE community network	Suggested KPI(s): # of EE ambassadors	Program documentation	 10	 15	 18	 18	 18
04	EE ambassadors test low-cost EE products[22]	Suggested KPI(s): # of units of free products provided	Program documentation	 20	 45	 54	 54	 54
06	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received EE products that can be endorsed by the Utilities are reviewed and identified (Yes/No)	Direct engagement & communication logs	 10 Yes	 5 Yes	 3 Yes	 2 Yes	 0 Yes
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	 0 8	 2 8	 4 8	 10 8	 0 -
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	-
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-	-

[20] Refer to the Program Design Report Exhibit 77 (Measures referred to as "Pilot")

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
20	The low-cost EE products will yield long-term electricity and demand savings (free products given away to increase the sales)	MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	1,064 91 32	1,667 237 84	1,454 362 129	1,141 460 164	928 538 192
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback1-to-10 scale, level of satisfaction with the products	Tracking System	7/10	7/10	7/10	7/10	-
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Utilities advertise their request for EE ambassadors	Suggested indicator(s): % EE ambassadors that heard about the opportunity through media / email / bill insert	EE ambassadors			80%		80%
02	Utilities conduct outreach activities at community events	No evaluation indicator	-			-		-
03	Utilities build an EE community network	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the EE ambassador network	EE ambassadors			7/10		7/10
04	EE ambassadors test low-cost EE products	No evaluation indicator	-			-		-
06	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation			70%		70%
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
14 & 19	Shoppers buy and install low-cost EE products[21]	Suggested indicator(s): # units sold	Retail store sales info (if available)	425	1,089	1,119	1,169	1,179
20	The low-cost EE products will yield long-term electricity and demand savings (increased sales achieved through education)	KPIs to be verified by evaluators. Suggested indicator(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Retail store sales info (if available)	785 78 28	2,302 306 109	2,218 533 190	2,399 776 277	2,413 1,020 364
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program 1-to-10 scale, level of satisfaction with their energy efficient products	Participants Participants			8/10 7/10		8/10 7/10

[21] Refer to the Program Design Report Exhibit 78 (Measures referred to as "Ed.")

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%		60% 30%
28	Non-energy benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the low cost EE product quality	Participants			9/10		9/10

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential Promotion of Low-Cost Energy Efficient Products. In addition, the following question will be explored:

- How effective are rebates, POP material, direct engagement at community events, and through the EE community network at increasing the sales of the low-cost EE products?
- How willing/able are retail store managers to share sales data to monitor the impact of the program?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential Promotion of Low-cost Energy Efficient Products* have implications on the evaluation methods employed:

- The Utilities will distribute many EE products free of charge (e.g. low-flow showerhead, faucet aerators, DHW tank insulation, DHW pipe insulation, etc.); and these alone will generate savings.
- This program element will promote the increase of market penetration and sales of low-cost energy efficient products as compare with “base” products. These incremental sales will generate significant impacts, much larger than that for the giveaways alone.
- None of the products will realize savings per building of over 10% of the total building electricity consumption, therefore utility billing analysis or whole-building M&V will not be an option.
- Site visit or field measurement campaign will not be practical for a jurisdiction of the size of Yukon. Hence it is recommended to follow a deemed savings approach and to use a TRM.
- Primarily, the impact will be computed based on the number of free low-cost EE products distributed. But the impact is not expected to be bound to the giveaways only. The evaluators will have to establish how the marketing, education, communication and the giveaways influenced the sales and increased the penetration of the targeted electricity efficient products.

- In addition, the education provided to Yukon residents as part of the direct community engagement activities will influence their behavior and may cause them to reduce their peak demand and electricity use. However, quantifying behavior-based electricity and demand savings is will not be estimated.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: retail store managers (p≈20), landlords (p≈50), shoppers (p≈20,000), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews with retail store managers, EE ambassadors, and phone or online surveys with participants and non-participants, but evaluators will be able to suggest an alternative approach if necessary. Mystery shoppers and retail intercepts might also be considered. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the community event booth materials, scorecard feedback, and media campaign material to review their quality and quantity (refer to the KPIs specified in the MBO framework).
- Review and validation of the approach and internal procedures to issuing rebates; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact evaluation for this program element needs to be carried out by monitoring the sales of low-cost electricity efficient products and their respective base cases. Therefore, it is critical to:
    - Consult with the store managers during the finalization of the EM&V plan and confirm their commitment to provide sales data for identified low-cost EE products during the 5-year DSM operations window. It is recommended to obtain a detailed commitment; agree on how and when the data will be available and what measures are going to be taken to ensure confidentiality.
    - If the evaluators are successful with the above, then the evaluators will lay out the method to estimate the savings based on the expected data in the final EM&V plan.
- Evaluators will estimate the incremental sales of EE products; then turn these figures and the number of giveaways in savings estimates using the program portfolio TRM.
- The TRM will be updated at three stages of the evaluation work to ensure the soundness of these estimates and to reduce the evaluation risk: at the EM&V plan finalization stage, at the evaluation process stage and at the final impact evaluation stage.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

4.7 Residential GSHP & CCHP Initiative

4.7.1 Program Description Summary

The Utilities will pilot cold climate heat pumps (CCHPs) and ground-source heat pumps (GSHPs). The pilot systems will be subsidized, not provided free of charge, and the results will be disseminated through different channels, such as HVAC contractors, electrical contractors, housing developers and municipalities.

After the completion of these pilot projects, the Utilities will provide a flat amount of money to buyers of new houses or condominium units if they buy a home with a cold climate heat pump (CCHP) or a ground-source heat pump (GSHP) system, or to owners of homes with electric central air heating systems to retrofit their home with a CCHP or a GSHP.

Eligible Measures

The preliminary list of technologies that the Utilities intend to promote includes the items presented in Exhibit 30.

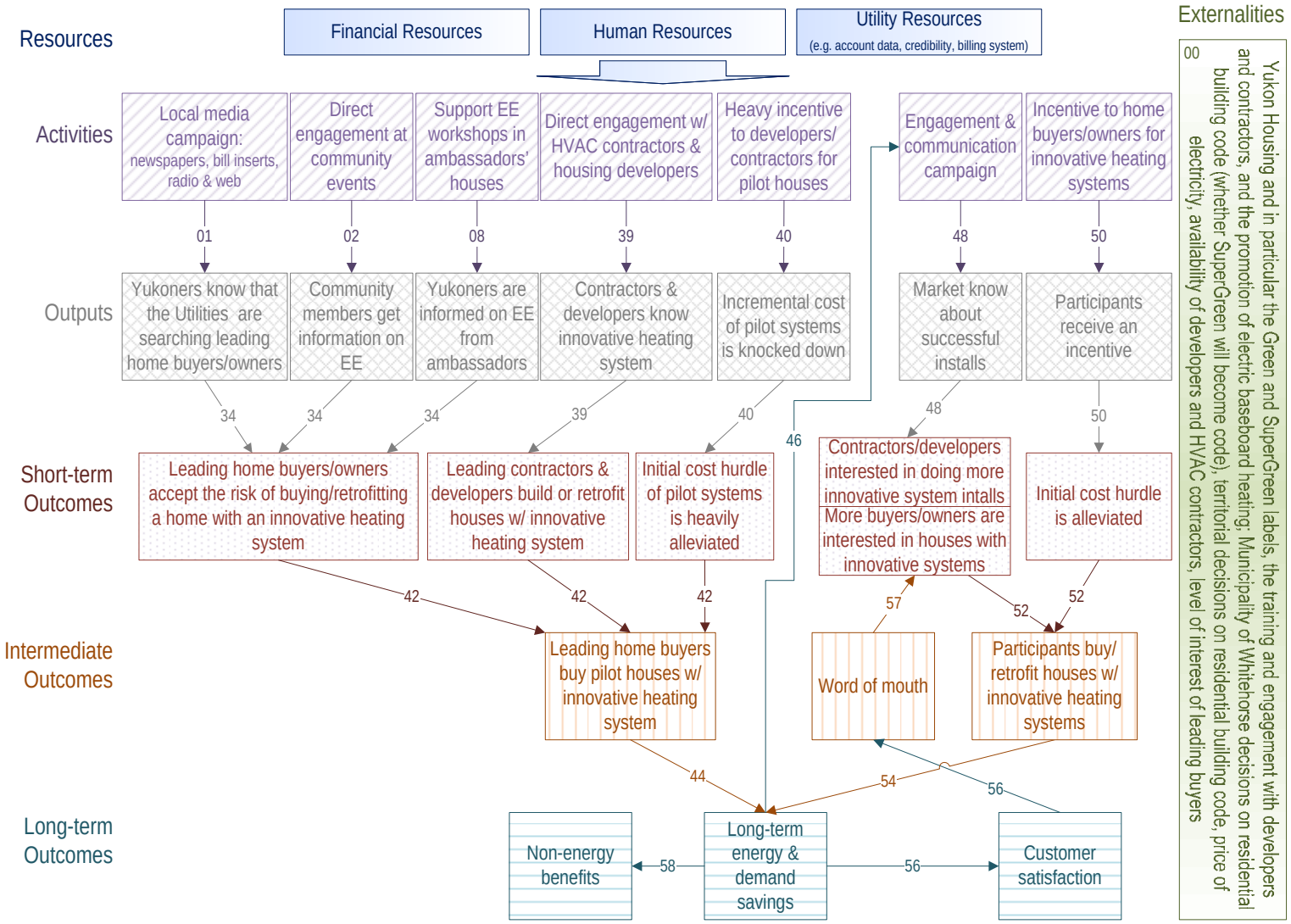
Exhibit 30: Inputs and Assumptions of Residential New-Construction GSHP and CCHP Initiative

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM032	Pilot Cold Temp Heat Pumps	6,780 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$5,000.00/unit
ECM372	Pilot Ground Heat Pumps - Closed	8,605 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$9,000.00/unit
ECM03	Cold Temp Heat Pumps	6,780.0 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$2,500.00/unit
ECM37	Ground Heat Pumps - Closed	8,605.0 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$3,500.00/unit

Program Theory

The program element theory is portrayed in the Logic Model below.

Exhibit 31: Logic Model for the Residential GSHP and CCHP Initiative



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: Yukon Housing, in particular the Green and SuperGreen labels, the training and engagement with developers and contractors, and the promotion of electric baseboard heating; Municipality of Whitehorse decisions on residential building code (whether SuperGreen will become code); territorial decisions on residential building code; price of electricity; availability of developers and HVAC contractors and level of interest of leading buyers. The program administrator should monitor these externalities and adapt the implementation approach accordingly.
01	The Utilities will advertise their intention to build an EE community network through the local press and applicable non-profit and community organizations. It is expected that this tactic will ease the development of the network.

Link #	Narrative
02	The Utilities will carry out outreach activities in community events (e.g., sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; offer to new home buyers to pilot CCHPs or GSHPs; and promote the idea of supporting a EE workshop at their home or a at local venue.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and innovative heating systems. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
34	Through community direct engagement tactics as detailed in links #01, #02 & #03, the Utilities will find leading home buyers or leading home owners who will accept the risk of buying a home with an innovative heating system.
39	The Utilities will engage directly with all of the HVAC contractors and housing developers in the Yukon. Because there only a few, it is realistic to speak with all of them. The Utilities will find leading developers and HVAC contractors who are willing take on the risk of building houses with innovative heating systems; or to retrofit existing homes with CCHP and GSHP systems. Their risk exposure will be reduced because the Utilities will help them find clients.
40	The Utilities will provide an incentive to the developers and contractors that will significantly reduce the total incremental cost of the technologies: not only the cost of the heat pump and the bore wells, but also the cost of the central air ductwork. The initial-cost hurdle of pilot houses will be heavily alleviated.
42	Developers will build pilot houses with innovative heating systems; and new home buyers will buy them because the Utilities will have found the buyers, matched them with the developers/contractors, and heavily subsidized the projects to address the initial-cost hurdle. Alternatively, innovative contractors will retrofit existing homes with innovative heating systems. The home owners will be willing to have their house pilot the system because the Utilities will have found leading home owners, matched them with innovative contractors, and heavily subsidized the projects to address the initial-cost hurdle.
44	The pilot houses with innovative heating systems will yield long-term electricity and demand savings. This electricity and demand savings will be verified and documented through state-of-the art project performance measurement and verification (M&V) activities.
46	The results of the pilot projects and of the M&V activities will feed the program planning; and will feed the engagement and communication campaign of the CCHP and GSHP incentive program component.
48	The Utilities deliver an engagement and communication campaign primarily through already-established channels: community direct engagement; and HVAC contractors and developers engagement. In addition, the Utilities will launch a local media campaign through local newspapers, local radios, brochures to be passed to prospective buyers by developers and contractors, email blasts, bill inserts and web content development. The Utilities will publicize the results of the pilot projects so that the market knows that the installations were successful and that CCHP and GSHP are viable technologies in the Yukon. As a result, developers and contractors will be interested in doing more CCHP and GSHP system installations, more home buyers will be interested in houses with these heating systems; and more home owners will be interested in retrofitting their houses with CCHP and GSHP systems.
50	The Utilities will provide a flat amount of money adjusted based on the capacity of the CCHP or the GSHP (per tons of refrigeration) installed and attributed to buyers of new houses or condominium units heated with a CCHP or a GSHP system; or to home owners willing to retrofit their houses with a CCHP or a GSHP system. The incentive level of CCHP and GSHP will differ. The incentive will alleviate the initial cost hurdle of CCHP and GSHP systems.
52	Because the supply and the demand will be stimulated, and because the initial-cost hurdle is alleviated, the participating home buyers or home owners (the participants) will buy houses with CCHP or GSHP systems.

Link #	Narrative
54	The houses of participants in the CCHP and GSHP incentive program component will yield long-term electricity and demand savings.
56	Participants will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
57	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy new houses with CCHP or GSHP systems; or to retrofit their houses with CCHP or GSHP systems.
58	It is assumed that the participants (pilot projects and incentive) will perceive new non-energy benefits; and/or the maintenance of benefits they used to have with baseline systems. The Utilities will seek to see the participants perceive that the comfort provided by CCHPs, and GSHPs is equivalent to what would be provided by baseboards heating.

4.7.2 Evaluation Considerations

Management-by-Objective Framework

Each connecting line in Exhibit 31 is associated with one or more performance indicators in the management by objective (MBO) framework shown in Exhibit 32. Performance indicators should be reviewed by the EM&V contractor to validate the theory. Explanatory notes on Exhibit 32 are provided in Section 4.1.2.

Exhibit 32: Management-by-Objective Framework for the Residential GSHP & CCHP Initiative

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	-
01	Utilities advertise their request for EE ambassadors	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 2 2 2	 1 1 1	 1 1 1	 1 1 1	 - - -
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth	Program documentation	2	1	1	1	1
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	0 8	1 8	1 8	1 8	0 -
34	Utilities identify leading home owners/buyers	Suggested KPI(s): # of leading home owners	Program documentation	1	1	1	1	-
39	Direct engagement with HVAC contractors and housing developers	Suggested KPI(s): # of HVAC contractors and developers contacted	Direct engagement & comm. logs	18	18	-	-	-
40 & 42	Utilities provide incentive for GSHP and CCHP pilot projects[22]	$ of incentive disbursement for pilot projects	Tracking System	$5K	$9K	$5K	$0	-

[22] Refer to Program Design Report Exhibit 84

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
46	Results of the pilot projects inform the innovative heating system incentive	No associated tracked KPIs	-	-	-	-	-	-
48	Utilities publicize results of the pilot projects	Suggested KPI(s): # updates of web content # press releases # bill insert	Program documentation	 - - -	 - - -	 - - -	 2 1 1	 2 1 1
50	Utilities provide incentive for innovative heating systems[23]	$ of incentive disbursement for innovative heating systems	Tracking System	$0	$0	$0	$19K	$19K
52	Home owners/managers agree to purchase innovative heating systems[24]	# of transactions in the innovative heating system incentive	Tracking System	-	-	-	7	7
44 & 54	The GSHP and CCHP pilot projects will yield long-term electricity and demand savings[25]	MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	148 7 3	188 17 6	188 26 9	1,223 87 31	1,075 141 50
57	Participants will be satisfied by the projects that they implemented	Suggested KPI(s): % of applications processed in under 10 business days	Tracking System	-	-	80%	80%	80%
56	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	-
58	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	-
Part B -- To Be Visited, Checked and Reported On by Evaluators				Baseline ↓		Process Eval. ↓		Impact Eval. ↓
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	Done
01	Utilities advertise their request for EE ambassadors	Suggested indicator(s): % EE ambassadors that heard about the opportunity through media / email / bill insert	EE ambassadors			80%		80%
02	Utilities conduct outreach activities at community events	No evaluation indicator	-			-		-
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees			7/10		7/10
34	Utilities identify leading home owners/buyers	No evaluation indicator	-			-		-
39	Direct engagement with HVAC contractors and housing developers	Suggested indicator(s): % HVAC contractors and developers who know the program	HVAC contractors and developers			90%		100%

[23] Refer to Program Design Report Exhibit 85
[24] Refer to Program Design Report Exhibit 84
[25] Refer to the Program Design Report Exhibit 86

Link #	Narrative	Performance Indicator	Sources	Target Year 1	Target Year 2	Target Year 3	Target Year 4	Target Year 5
40 & 42	Utilities provide incentive for pilot projects[26]	Suggested indicator(s): % HVAC contractors/developers (that did not participate in the pilot projects) that heard about the results	Non-participants			80%		80%
46	Results of the pilot projects inform the innovative heating system incentive	Suggested indicator(s): Yes/No pilot project results provided ground to proceed with a full-fledge incentive program for innovative heating system in Yukon	Program documentation			Yes		
48	Utilities publicize results of the pilot projects	Suggested indicator(s): % HVAC contractors/developers (that did not participate in the pilot projects) that heard about the results	Non-participants					100%
50	Utilities provide incentive for innovative heating systems[27]	Suggested indicator(s): % of participants who agree that the incentive got them to install a more sophisticated heating system then they would have otherwise	Participants					60%
		% of participating suppliers who confirm the above	Supply-chain actors					60%
52	Home owners/managers agree to purchase innovative heating systems[28]	No evaluation indicator	-			-		-
44 & 54	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator KPIs to be verified by evaluators.	-			-		-
57	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program	Participants			8/10		8/10
		1-to-10 scale, level of satisfaction with their energy efficient products	Participants			7/10		7/10
56	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants			30%		60%
		% heard of the program positively from past participants	Non-participants			10%		30%
58	Non-energy benefits	Suggested indicator(s): 1-to-10 scale, level of satisfaction with interior comfort provided	Participants			9/10		9/10
		1-to-10 scale, level of satisfaction with the level of effort and cost to maintain the system				8/10		8/10

[26] Refer to Program Design Report Exhibit 84
[27] Refer to Program Design Report Exhibit 85
[28] Refer to Program Design Report Exhibit 84

Program-Specific Research Questions

Evaluators will be asked to conduct a review of program data and documents, market research, stakeholder consultation, literature review and analysis in order to answer research questions. Many questions will find partial answers through monitoring the performance indicators in the MBO Framework above, but evaluators will research additional issues to make sure their answers are exhaustive, useful and well substantiated.

The generic research questions presented in Section 3.2 are applicable to the Residential CCHP and GSHP Initiative. In addition, the following question will be explored:

- Based on the pilot projects, should the Utilities proceed with a full-fledged incentive program for CCHP and/or GSHP?

Suggested Evaluation Methods and Level of Rigor

The following key observations and characteristics of the *Residential GSHP & CCHP Initiative* have implications on the evaluation methods employed:

- Relatively few projects are anticipated (4 pilot projects and 14 incentive projects), therefore transactional infrastructure will be rudimentary and documentation will be on a project-by-project basis.
- An aggregate of the project-level M&V results of each of the pilot projects can be fed into the program-level evaluation.
- The later incentive-eligible projects will be few (14 projects are estimated). Thus, it is recommended to have the inCharge staff (for example: the YEC Energy Conservation Coordinator) use the same M&V method as were used for the pilot projects.
- The pilot projects are planned to be implemented between Y1-Q4 and Y3-Q2, and thus the post-retrofit measurement period – expected to last for one year – is to end between Y2-Q4 and Y3-Q3.
- It is expected that the program element will involve or have implications on the following market actors and stakeholders: HVAC/control designers and contractors (p≈18), property managers (p≈8 large), housing developers (p≈8), the Yukon Energy Solutions Centre, and the Yukon Housing Corporation.

Based on the above, the suggested *process evaluation* methods are:

- Consult with the relevant market actors listed above. The evaluators are to suggest sample sizes. The most likely approach to consultation will be directed in-depth interviews, but evaluators will be able to suggest an alternative approach if necessary. Evaluators should have a fair level of confidence in the representativeness of the answers based on their expertise and experience.
- Review of the technical assistance reports provided to participants to assess soundness of calculations and the proposed solutions.
- Review and validation of the approach and internal procedures to site visits; review of the documentation to date.

Also based on the observations above, the suggested *impact evaluation* methods are:

- Impact of this program element will be evaluated based on the aggregated results of all of the project-level M&V reports completed for each of the pilot projects and for each of the later projects. The approach to M&V will follow an Option-C methodology of the IPMVP; that is: whole-building electricity consumption measurement using the main utility meter. The baseline will be established based on at least 12-months' worth of

utility bills prior to construction; and the post-retrofit measurement period is to last for 12 months. The baseline will be adjusted based on one or many relevant independent parameters including at least the heating degree-days. Please refer to Section 3.2 for additional details.

- Since the M&V estimates for the later projects are going to be made by inCharge staff, the evaluators are to carry out a desk review of these calculations.
- GSHP & CCHP systems are very new in Yukon, thus there will be very few distortion effects. Consequently it is recommended to use a stipulated NTG ratio of 1.
- Consultation (2nd consultation) with relevant market actors and stakeholders to revisit a few relevant evaluation indicators as laid out in the MBO framework.

5. Procurement of Third-Party Evaluation Services

The Utilities intend to select one independent EM&V contractor through a competitive tendering process who will evaluate both the General Service Program and the Residential Program. A committee of staff from both Utilities will select the contractor. The following observations are provided for consideration by the Utilities in this procurement process.

- Potential bidders can be identified through the International Energy Program Evaluation Conference (IEPEC) as most active North-American evaluators participate in this bi-annual conference. Their names will appear among the sponsors and in the conference proceedings.
- DSM evaluation contractors are usually multi-disciplinary teams with capabilities in social science research, marketing, energy policy, economics, statistics, energy analytics, energy engineering and project-level M&V. It is good for an evaluation contractor to have Certified Measurement and Verification Professionals (CMVP) among the team.
- Some Utilities employ a two-step procurement process. The first step is to submit a Request for Qualifications (RFQ). Qualifying firms would be placed on a short list of two to five bidders. Creating a short-list of bidders has the following benefits:
  - Reduces the level of effort required by the selection committee.
  - Limits the dissemination of information about the program – some that might be confidential – to fewer companies.
  - Tends to increase the response rate and overall proposal quality as the respondents know that they are bidding against a smaller, select number of competitors.
- It is standard practice to share program information with the evaluation bidders. If desirable, the information can be shared on a confidential basis. Increasing the information that is shared before the bid will allow the evaluators to prepare proposals with a greater level of detail.
- This EM&V plan can also serve as an information package for the bidders. If it is not possible to share the EM&V plan with the bidders, then it is suggested that the Utilities include the following items in their request for proposals:
  - The scale of the program in terms of impact and budget. This will allow bidders to estimate the level of effort, to decide on the preferable level of rigor, and to get a general feel for the total evaluation budget.
  - The applicable evaluation best practices (See section 2.5). This would help standardize the terminology among proposals.
  - The program documentation that will be available to them early after signing the EM&V contract. Knowing what pieces of documentation and information exist will make bidders appreciate the professionalism of the approach. This should reduce their perception of risk and in turn increase the number of serious contenders.[29]

[29] The Utilities could inform bidders about the availability of the following information: an EM&V plan; a CPR report; market characterization reports; program design document; PIP and Year-1 program startup progress reports; program theory, logic models, KPIs and targets; program tracking system and program database; the deemed-savings estimates, an ex-ante cost-effectiveness model, and a draft technical reference manual; and, draft with site verifications protocols for use by DSM staff on a routine basis.

- Bidders should be allowed to propose methods that are different from those in the current EM&V plan, if they deem it appropriate. This approach will allow the Yukon stakeholders to tap into the creativity of a larger pool of methodologists.
- The bidders should be asked to present a list of data that they plan to collect, either as part of the proposal or during the inception of the EM&V work. Typically, these data are presented as a table of researchable issues.

YUB-YECL-27

Reference: Allocation of promotional and educational costs, Yukon Five Year Demand Side Management Plan, page 14

Benefit/Cost results are not calculated for program elements that are promotional or educational in nature; however, their associated costs are captured and distributed among those program elements that do create electricity savings.

The Board wants to better understand how these promotional or educational costs will be allocated among the different programs.

Request:

Please describe the methodology that YEC and YECL used to decide how much of the promotional or educational costs are allocated to each program.

Response:

In the model used to design the programs, these costs are allocated to the residential or the general service segment using bottom-up budgetary estimates. These costs are not allocated to the direct-impact program elements. Program administration costs are accounted for in the non-incentive level costs per measure and can be found in the *DSM Program Incentive Level Justification*, provided as YUB-YECL-27 Attachment 1.

Appendix D Incentive Level Justification

Energy Conservation Measure - Justification of the Incentive Level

The purpose of this worksheet is to explain the metholodogy used to calculate the incentive levels for measures in the General Service Program requiring an alternative approach compared to the the one used for the other measures in the Program portfolio.

Redesign Measures

ECM91	Lighting Resdeign Study
ECM912	Gov. Lighting Redesign Study

The incentive levels for the resdesign measures were computed using a trial and error method. Because there are no savings associated with these measures, the cost effectiveness results were computed at the program level instead of at the individual measure level.

Lighting Measures

ECM80	Typical Lighting Project in Existing Bldg - Office
ECM82	Typical Lighting Project in Existing Bldg - Non Food Retail
ECM83	Typical Lighting Project in Existing Bldg - Hotel/Motel
ECM86	Typical Lighting Project in Existing Bldg - Restaurant
ECM87	Typical Lighting Project in Existing Bldg - Recreation
ECM88	Typical Lighting Project in Existing Bldg - Warehouse
ECM92	Commercial 12W LED A19 Bulb
ECM93	Commercial 8W LED A19 Bulb
ECM94	Commercial LED MR16 Bulbs
ECM95	Commercial LED PAR30 Bulbs
ECM96	Commercial LED PAR38 Bulbs
ECM97	Commercial Spot or task lighting
ECM802	Gov. Typical Lighting Project in Existing Bldg - Office
ECM842	Gov. Typical Lighting Project in Existing Bldg - Health
ECM852	Gov. Typical Lighting Project in Existing Bldg - Education
ECM872	Gov. Typical Lighting Project in Existing Bldg - Recreation
ECM882	Gov. Typical Lighting Project in Existing Bldg - Warehouse
ECM922	Gov. Commercial 12W LED A19 Bulb
ECM932	Gov. Commercial 8W LED A19 Bulb
ECM942	Gov. Commercial LED MR16 Bulbs
ECM952	Gov. Commercial LED PAR30 Bulbs
ECM962	Gov. Commercial LED PAR38 Bulbs
ECM972	Gov. Commercial Spot or task lighting

The total lighting incentive is made up of a custom portion and a prescriptive portion. The custom incentive provides flexibility in the choice of lighting technologies and also encourages contractors and designers to be innovative. The custom incentive was calculated using a dollar value per annual kilowatt hour of savings. This value was established using a trial and error procedure and evaluation of the cost-effectiveness results on the program-element level. The purpose of the prescriptive incentive is to increase the incentive total if LED lamps are used, since the initial-cost hurdle is higher for LED technologies than for other technoclogies. The prescriptive incentive also aims to accelerate the market penetration of LEDs. The prescriptive lighting incentive levels in the General Service Program are idential to those in the Residential Program.

Due to limitations of the model, it was not possible to compute the cost-effectiveness test results for the lighting measures on a measure by measure basis. However, the model did allow for the accurate calculation of the cost-effectiveness test results for these measures on the program level.

Energy Conservation Measure - Justification of the Incentive Level

ECM98

Inputs - Measure Considerations	
Measure Name: Typical Low-Cost No-Cost Refrigeration Project - Food Retail	
Incentive Amount:	$1.31/ft2
Measure/Project Cost:	$1.73/ft2
Gross Consumption Savings:	6.6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7.1 kWh/ft2/yr
Gross Demand Savings:	.00074 kW/ft2
Gross Demand Savings w/ T&D losses:	.00081 kW/ft2
Participant's Savings on Year 1:	$1.13/ft2
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	90%
Suggested Program Cost (% of Incentive):	90%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	6.04
PC - Net Present Value	$8.70
PC - Levelized Cost	$0.0354/kWh
Simple Payback w/ Incentive (yr)	0.4 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$0.32*
RIM - Levelized Cost	*$0.2209/kWh*
TRC - Benefit/Cost Ratio	4.07
TRC - Net Present Value	$8.65
TRC - Levelized Cost	$0.0558/kWh
PAC - Benefit/Cost Ratio	*4.61*
PAC - Net Present Value	*$8.98*
PAC - Levelized Cost	*$0.0493/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$3.96*
RIM-YECL - Levelized Cost	*$0.1713/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.56*
RIM-YEC - Net Present Value	*$3.82*
RIM-YEC - Levelized Cost	*$0.1299/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$1.73
Incentive Amount in Year 1	$1.31
Assumed Program Administration Costs in Year 1	$1.18
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$9.11	$9.11
Discounted Cumulative Gross Energy Savings for 10 years	49 kWh	49 kWh
PC - Present Value of Benefits	$10.42	$10.42
PC - Present Value of Costs	$1.73	$1.73
PC - Benefit/Cost Ratio	6.04	6.04
PC - Net Present Value	$8.70	$8.70
PC - Levelized Cost	$0.0354/kWh	$0.0354/kWh
Simple Payback with Incentive	0.4 yr	0.4 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$8.66	$8.66
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
RIM - Present Value of Benefits	$11.47	$11.47
RIM - Present Value of Costs	$11.15	$9.97
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.32	$1.50
RIM - Levelized Cost	$0 2209/kWh	$0.1976/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
TRC - Present Value of Benefits	$11.47	$11.47
TRC - Present Value of Costs	$2.82	$1.64
TRC - Benefit/Cost Ratio	4.07	7.0
TRC - Net Present Value	$8.65	$9.83
TRC - Levelized Cost	$0.0558/kWh	$0.0325/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$11.47	$11.47
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	50 kWh	50 kWh
PAC - Present Value of Benefits	$11.47	$11.47
PAC - Present Value of Costs	$2.49	$1.31
PAC - Benefit/Cost Ratio	4.6	8.8
PAC - Net Present Value	$8.98	$10.16
PAC - Levelized Cost	$0.0493/kWh	$0.0260/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM99

Inputs - Measure Considerations	
Measure Name:	Typical Deep Retrofit Refrigeration Project - Food Retail
Incentive Amount:	$2.70/ft2
Measure/Project Cost:	$5.87/ft2
Gross Consumption Savings:	13.5 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	14.7 kWh/ft2/yr
Gross Demand Savings:	.00153 kW/ft2
Gross Demand Savings w/ T&D losses:	.00167 kW/ft2
Participant's Savings on Year 1:	$2.33/ft2
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	90%
Suggested Program Cost (% of Incentive):	90%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.66
PC - Net Present Value	$15.58
PC - Levelized Cost	$0.0585/kWh
Simple Payback w/ Incentive (yr)	1.4 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$0.66*
RIM - Levelized Cost	*$0.2209/kWh*
TRC - Benefit/Cost Ratio	2.95
TRC - Net Present Value	$15.60
TRC - Levelized Cost	$0.0770/kWh
PAC - Benefit/Cost Ratio	*4.61*
PAC - Net Present Value	*$18.48*
PAC - Levelized Cost	*$0.0493/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$8.14*
RIM-YECL - Levelized Cost	*$0.1713/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.56*
RIM-YEC - Net Present Value	*$7.86*
RIM-YEC - Levelized Cost	*$0.1299/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$5.87
Incentive Amount in Year 1	$2.70
Assumed Program Administration Costs in Year 1	$2.42
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$18.75	$18.75
Discounted Cumulative Gross Energy Savings for 10 years	100 kWh	100 kWh
PC - Present Value of Benefits	$21.45	$21.45
PC - Present Value of Costs	$5.87	$5.87
PC - Benefit/Cost Ratio	3.66	3.66
PC - Net Present Value	$15.58	$15.58
PC - Levelized Cost	$0.0585/kWh	$0.0585/kWh
Simple Payback with Incentive	1.4 yr	1.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$17.82	$17.82
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
RIM - Present Value of Benefits	$23.60	$23.60
RIM - Present Value of Costs	$22.93	$20.51
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.66	$3.09
RIM - Levelized Cost	$0 2209/kWh	$0.1976/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
TRC - Present Value of Benefits	$23.60	$23.60
TRC - Present Value of Costs	$7.99	$5.57
TRC - Benefit/Cost Ratio	2.95	4 2
TRC - Net Present Value	$15.60	$18.03
TRC - Levelized Cost	$0.0770/kWh	$0.0537/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$23.60	$23.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	104 kWh	104 kWh
PAC - Present Value of Benefits	$23.60	$23.60
PAC - Present Value of Costs	$5.12	$2.70
PAC - Benefit/Cost Ratio	4.6	8.8
PAC - Net Present Value	$18.48	$20.90
PAC - Levelized Cost	$0.0493/kWh	$0.0260/kWh

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Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1002

Inputs - Measure Considerations

Measure Name:	Typical Refrigeration Project - Ice Rink
Incentive Amount:	$0.40/ft2
Measure/Project Cost:	$0.72/ft2
Gross Consumption Savings:	2.5 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	2.7 kWh/ft2/yr
Gross Demand Savings:	.00034 kW/ft2
Gross Demand Savings w/ T&D losses:	.00037 kW/ft2
Participant's Savings on Year 1:	$0.43/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	111%
Suggested Program Cost (% of Incentive):	111%
Forecasted Freeridership:	5%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	10.01
PC - Net Present Value	$6.50
PC - Levelized Cost	$0.0261/kWh
Simple Payback w/ Incentive (yr)	0.7 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$0.33*
RIM - Levelized Cost	*$0.2553/kWh*
TRC - Benefit/Cost Ratio	6.20
TRC - Net Present Value	$5.87
TRC - Levelized Cost	$0.0393/kWh
PAC - Benefit/Cost Ratio	*8.31*
PAC - Net Present Value	*$6.15*
PAC - Levelized Cost	*$0.0294/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$3.43*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*2.11*
RIM-YEC - Net Present Value	*$4.00*
RIM-YEC - Levelized Cost	*$0.1161/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.72
Incentive Amount in Year 1	$0.40
Assumed Program Administration Costs in Year 1	$0.44
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$6.82	$6.82
Discounted Cumulative Gross Energy Savings for 20 years	28 kWh	28 kWh
PC - Present Value of Benefits	$7.22	$7.22
PC - Present Value of Costs	$0.72	$0.72
PC - Benefit/Cost Ratio	10.01	10.01
PC - Net Present Value	$6.50	$6.50
PC - Levelized Cost	$0.0261/kWh	$0.0261/kWh
Simple Payback with Incentive	0.7 yr	0.7 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$6.48	$6.48
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
RIM - Present Value of Benefits	$7.00	$7.00
RIM - Present Value of Costs	$7.33	$6.88
RIM - Benefit/Cost Ratio	1.0	1.0
RIM - Net Present Value	-$0.33	$0.11
RIM - Levelized Cost	$0 2553/kWh	$0.2398/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
TRC - Present Value of Benefits	$7.00	$7.00
TRC - Present Value of Costs	$1.13	$0.69
TRC - Benefit/Cost Ratio	6.20	10 2
TRC - Net Present Value	$5.87	$6.31
TRC - Levelized Cost	$0.0393/kWh	$0.0239/kWh

Program Administrator Cost Test from YEC Perspective (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$7.00	$7.00
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	29 kWh	29 kWh
PAC - Present Value of Benefits	$7.00	$7.00
PAC - Present Value of Costs	$0.84	$0.40
PAC - Benefit/Cost Ratio	8.3	17 5
PAC - Net Present Value	$6.15	$6.60
PAC - Levelized Cost	$0.0294/kWh	$0.0139/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM101

Inputs - Measure Considerations	
Measure Name:	ES Desktop Computer and Monitor
Incentive Amount:	$30.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	148 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	161 kWh/yr
Gross Demand Savings:	0.03 kW
Gross Demand Savings w/ T&D losses:	0.03 kW
Participant's Savings on Year 1:	$25.59
Measure Lifetime:	4 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	211%
Suggested Program Cost (% of Incentive):	211%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	*
PC - Net Present Value	$125.01
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-1.2 yr
RIM - Benefit/Cost Ratio	*0.65*
RIM - Net Present Value	*-$64.08*
RIM - Levelized Cost	*$0.3318/kWh*
TRC - Benefit/Cost Ratio	1.89
TRC - Net Present Value	$56.18
TRC - Levelized Cost	$0.1145/kWh
PAC - Benefit/Cost Ratio	*1.28*
PAC - Net Present Value	*$26.18*
PAC - Levelized Cost	*$0.1687/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$42.38*
RIM-YECL - Levelized Cost	*$0.1630/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.14*
RIM-YEC - Net Present Value	*$19.73*
RIM-YEC - Levelized Cost	*$0.2446/kWh*

Reference Data from Other Jurisdictions:

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$30.00
Assumed Program Administration Costs in Year 1	$63.38
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$95.01	$95.01
Discounted Cumulative Gross Energy Savings for 4 years	534 kWh	534 kWh
PC - Present Value of Benefits	$125.01	$125.01
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$125.01	$125.01
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-1 2 yr	-1.2 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$90.26	$90.26
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
RIM - Present Value of Benefits	$119.56	$119.56
RIM - Present Value of Costs	$183.64	$120.26
RIM - Benefit/Cost Ratio	0.7	1.0
RIM - Net Present Value	-$64.08	-$0.70
RIM - Levelized Cost	$0 3318/kWh	$0.2173/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
TRC - Present Value of Benefits	$119.56	$119.56
TRC - Present Value of Costs	$63.38	$0.00
TRC - Benefit/Cost Ratio	1.89	*
TRC - Net Present Value	$56.18	$119.56
TRC - Levelized Cost	$0.1145/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$119.56	$119.56
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	554 kWh	554 kWh
PAC - Present Value of Benefits	$119.56	$119.56
PAC - Present Value of Costs	$93.38	$30.00
PAC - Benefit/Cost Ratio	1.3	4.0
PAC - Net Present Value	$26.18	$89.56
PAC - Levelized Cost	$0.1687/kWh	$0.0542/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM102

Inputs - Measure Considerations	
Measure Name:	ES Laptop Computer
Incentive Amount:	$10.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	41 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	45 kWh/yr
Gross Demand Savings:	0.01 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$7.09
Measure Lifetime:	4 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	211%
Suggested Program Cost (% of Incentive):	211%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	*
PC - Net Present Value	$36.32
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-1.4 yr
RIM - Benefit/Cost Ratio	*0.59*
RIM - Net Present Value	*-$23.01*
RIM - Levelized Cost	*$0.3661/kWh*
TRC - Benefit/Cost Ratio	1.57
TRC - Net Present Value	$12.00
TRC - Levelized Cost	$0.1378/kWh
PAC - Benefit/Cost Ratio	*1.06*
PAC - Net Present Value	*$2.00*
PAC - Levelized Cost	*$0.2030/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$11.74*
RIM-YECL - Levelized Cost	*$0.1630/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.00*
RIM-YEC - Net Present Value	*$0.21*
RIM-YEC - Levelized Cost	*$0.2784/kWh*

Reference Data from Other Jurisdictions:

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$21.13
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$26.32	$26.32
Discounted Cumulative Gross Energy Savings for 4 years	148 kWh	148 kWh
PC - Present Value of Benefits	$36.32	$36.32
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$36.32	$36.32
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-1.4 yr	-1.4 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$25.00	$25.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
RIM - Present Value of Benefits	$33.12	$33.12
RIM - Present Value of Costs	$56.13	$35.00
RIM - Benefit/Cost Ratio	0.6	0 9
RIM - Net Present Value	-$23.01	-$1.88
RIM - Levelized Cost	$0 3661/kWh	$0.2283/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
TRC - Present Value of Benefits	$33.12	$33.12
TRC - Present Value of Costs	$21.13	$0.00
TRC - Benefit/Cost Ratio	1.57	*
TRC - Net Present Value	$12.00	$33.12
TRC - Levelized Cost	$0.1378/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$33.12	$33.12
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	153 kWh	153 kWh
PAC - Present Value of Benefits	$33.12	$33.12
PAC - Present Value of Costs	$31.13	$10.00
PAC - Benefit/Cost Ratio	1.1	3 3
PAC - Net Present Value	$2.00	$23.12
PAC - Levelized Cost	$0 2030/kWh	$0.0652/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1012

Inputs - Measure Considerations

Measure Name:	Gov. ES Desktop Computer and Monitor
Incentive Amount:	$18.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	148 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	161 kWh/yr
Gross Demand Savings:	0.03 kW
Gross Demand Savings w/ T&D losses:	0.03 kW
Participant's Savings on Year 1:	$31.41
Measure Lifetime:	4 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	189%
Suggested Program Cost (% of Incentive):	189%
Forecasted Freeridership:	50%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	*
PC - Net Present Value	$134.62
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-0.6 yr
RIM - Benefit/Cost Ratio	*0.60*
RIM - Net Present Value	*-$46.89*
RIM - Levelized Cost	*$0.3623/kWh*
TRC - Benefit/Cost Ratio	2.04
TRC - Net Present Value	$35.25
TRC - Levelized Cost	$0.1060/kWh
PAC - Benefit/Cost Ratio	*1.33*
PAC - Net Present Value	*$17.25*
PAC - Levelized Cost	*$0.1622/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$36.24*
RIM-YECL - Levelized Cost	*$0.2001/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.91*
RIM-YEC - Net Present Value	*-$7.18*
RIM-YEC - Levelized Cost	*$0.2381/kWh*

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$18.00
Assumed Program Administration Costs in Year 1	$33.97
Assumed Net-to-gross Ratio	55%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$116.62	$116.62
Discounted Cumulative Gross Energy Savings for 4 years	534 kWh	534 kWh
PC - Present Value of Benefits	$134.62	$134.62
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$134.62	$134.62
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-0.6 yr	-0.6 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test from YEC Perspective (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$64.14	$64.14
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
RIM - Present Value of Benefits	$69.22	$69.22
RIM - Present Value of Costs	$116.11	$82.14
RIM - Benefit/Cost Ratio	0.6	0.8
RIM - Net Present Value	-$46.89	-$12.92
RIM - Levelized Cost	$0 3623/kWh	$0.2563/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
TRC - Present Value of Benefits	$69.22	$69.22
TRC - Present Value of Costs	$33.97	$0.00
TRC - Benefit/Cost Ratio	2.04	*
TRC - Net Present Value	$35.25	$69.22
TRC - Levelized Cost	$0.1060/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test from YEC Perspective (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$69.22	$69.22
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	320 kWh	320 kWh
PAC - Present Value of Benefits	$69.22	$69.22
PAC - Present Value of Costs	$51.97	$18.00
PAC - Benefit/Cost Ratio	1.3	3.8
PAC - Net Present Value	$17.25	$51.22
PAC - Levelized Cost	$0.1622/kWh	$0.0562/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM1022

Inputs - Measure Considerations	
Measure Name:	Gov. ES Laptop Computer
Incentive Amount:	$6.00
Measure/Project Cost:	$0.00
Gross Consumption Savings:	41 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	45 kWh/yr
Gross Demand Savings:	0.01 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$8.70
Measure Lifetime:	4 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	189%
Suggested Program Cost (% of Incentive):	189%
Forecasted Freeridership:	50%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	*
PC - Net Present Value	$38.31
PC - Levelized Cost	$0.0000/kWh
Simple Payback w/ Incentive (yr)	-0.7 yr
RIM - Benefit/Cost Ratio	*0.55*
RIM - Net Present Value	*-$15.92*
RIM - Levelized Cost	*$0.3953/kWh*
TRC - Benefit/Cost Ratio	1.69
TRC - Net Present Value	$7.85
TRC - Levelized Cost	$0.1276/kWh
PAC - Benefit/Cost Ratio	*1.11*
PAC - Net Present Value	*$1.85*
PAC - Levelized Cost	*$0.1951/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$10.04*
RIM-YECL - Levelized Cost	*$0.2001/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.80*
RIM-YEC - Net Present Value	*-$4.91*
RIM-YEC - Levelized Cost	*$0.2706/kWh*

Reference Data from Other Jurisdictions:

*There is no incremental cost to the Participant to purchase an ENERGY STAR computer.

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.00
Incentive Amount in Year 1	$6.00
Assumed Program Administration Costs in Year 1	$11.32
Assumed Net-to-gross Ratio	55%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 4 years	$32.31	$32.31
Discounted Cumulative Gross Energy Savings for 4 years	148 kWh	148 kWh
PC - Present Value of Benefits	$38.31	$38.31
PC - Present Value of Costs	$0.00	$0.00
PC - Benefit/Cost Ratio	*	*
PC - Net Present Value	$38.31	$38.31
PC - Levelized Cost	$0.0000/kWh	$0.0000/kWh
Simple Payback with Incentive	-0.7 yr	-0.7 yr

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Ratepayer Impact Measure Test from YEC Perspective (RIM)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Present Value of Lost Revenues for 4 years	$17.77	$17.77
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
RIM - Present Value of Benefits	$19.18	$19.18
RIM - Present Value of Costs	$35.09	$23.77
RIM - Benefit/Cost Ratio	0.5	0.8
RIM - Net Present Value	-$15.92	-$4.59
RIM - Levelized Cost	$0 3953/kWh	$0.2677/kWh

Total Resource Cost Test (TRC)

Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
TRC - Present Value of Benefits	$19.18	$19.18
TRC - Present Value of Costs	$11.32	$0.00
TRC - Benefit/Cost Ratio	1.69	*
TRC - Net Present Value	$7.85	$19.18
TRC - Levelized Cost	$0.1276/kWh	$0.0000/kWh

*Incremental cost to purchase an ENERGY STAR computer is $0.00.

Program Administrator Cost Test from YEC Perspective (PAC)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 4 years	$19.18	$19.18
Present Value of Avoided Capacity Costs for 4 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 4 years	89 kWh	89 kWh
PAC - Present Value of Benefits	$19.18	$19.18
PAC - Present Value of Costs	$17.32	$6.00
PAC - Benefit/Cost Ratio	1.1	3 2
PAC - Net Present Value	$1.85	$13.18
PAC - Levelized Cost	$0.1951/kWh	$0.0676/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM89

Inputs - Measure Considerations	
Measure Name:	Typical High-Performance New Building - 25% Better
Incentive Amount:	$1.50/ft2
Measure/Project Cost:	$2.00/ft2
Gross Consumption Savings:	6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	6 kWh/ft2/yr
Gross Demand Savings:	.001 kW/ft2
Gross Demand Savings w/ T&D losses:	.001 kW/ft2
Participant's Savings on Year 1:	$1.03/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost Per Unit:	250%
Suggested Program Cost ($ per Unit):	$1.64
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	7.36
PC - Net Present Value	$12.72
PC - Levelized Cost	$0.0304/kWh
Simple Payback w/ Incentive (yr)	0.5 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.08*
RIM - Levelized Cost	*$0.2427/kWh*
TRC - Benefit/Cost Ratio	3.78
TRC - Net Present Value	$12.24
TRC - Levelized Cost	$0.0645/kWh
PAC - Benefit/Cost Ratio	*4.16*
PAC - Net Present Value	*$12.64*
PAC - Levelized Cost	*$0.0586/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$5.53*
RIM-YECL - Levelized Cost	*$0.1829/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.58*
RIM-YEC - Net Present Value	*$6.12*
RIM-YEC - Levelized Cost	*$0.1432/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$2.00
Incentive Amount in Year 1	$1.50
Assumed Program Administration Costs in Year 1	$2.50
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$13.22	$13.22
Discounted Cumulative Gross Energy Savings for 20 years	66 kWh	66 kWh
PC - Present Value of Benefits	$14.72	$14.72
PC - Present Value of Costs	$2.00	$2.00
PC - Benefit/Cost Ratio	7.36	7.36
PC - Net Present Value	$12.72	$12.72
PC - Levelized Cost	$0.0304/kWh	$0.0304/kWh
Simple Payback with Incentive	0 5 yr	0.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12.56	$12.56
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
RIM - Present Value of Benefits	$16.64	$16.64
RIM - Present Value of Costs	$16.56	$14.06
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$0.08	$2.58
RIM - Levelized Cost	$0 2427/kWh	$0.2060/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
TRC - Present Value of Benefits	$16.64	$16.64
TRC - Present Value of Costs	$4.40	$1.90
TRC - Benefit/Cost Ratio	3.78	8.8
TRC - Net Present Value	$12.24	$14.74
TRC - Levelized Cost	$0.0645/kWh	$0.0278/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
PAC - Present Value of Benefits	$16.64	$16.64
PAC - Present Value of Costs	$4.00	$1.50
PAC - Benefit/Cost Ratio	4.2	11.1
PAC - Net Present Value	$12.64	$15.14
PAC - Levelized Cost	$0.0586/kWh	$0.0220/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM90

Inputs - Measure Considerations	
Measure Name:	Typical High-Performance New Building - 40% Better
Incentive Amount:	$4.00/ft2
Measure/Project Cost:	$6.00/ft2
Gross Consumption Savings:	9 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	10 kWh/ft2/yr
Gross Demand Savings:	.002 kW/ft2
Gross Demand Savings w/ T&D losses:	.002 kW/ft2
Participant's Savings on Year 1:	$1.64/ft2
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost Per Unit:	250%
Suggested Program Cost ($ per Unit):	$2.63
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.19
PC - Net Present Value	$19.15
PC - Levelized Cost	$0.0569/kWh
Simple Payback w/ Incentive (yr)	1.2 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.02*
RIM - Levelized Cost	*$0.2436/kWh*
TRC - Benefit/Cost Ratio	3.25
TRC - Net Present Value	$18.42
TRC - Levelized Cost	$0.0751/kWh
PAC - Benefit/Cost Ratio	*4.09*
PAC - Net Present Value	*$20.12*
PAC - Levelized Cost	*$0.0595/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.52*
RIM-YECL - Net Present Value	*-$8.85*
RIM-YECL - Levelized Cost	*$0.1829/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.57*
RIM-YEC - Net Present Value	*$9.69*
RIM-YEC - Levelized Cost	*$0.1441/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$6.00
Incentive Amount in Year 1	$4.00
Assumed Program Administration Costs in Year 1	$2.50
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spillover N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$21.15	$21.15
Discounted Cumulative Gross Energy Savings for 20 years	105 kWh	105 kWh
PC - Present Value of Benefits	$25.15	$25.15
PC - Present Value of Costs	$6.00	$6.00
PC - Benefit/Cost Ratio	4.19	4.19
PC - Net Present Value	$19.15	$19.15
PC - Levelized Cost	$0.0569/kWh	$0.0569/kWh
Simple Payback with Incentive	1 2 yr	1.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$20.09	$20.09
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
RIM - Present Value of Benefits	$26.62	$26.62
RIM - Present Value of Costs	$26.59	$24.09
RIM - Benefit/Cost Ratio	1.0	1.1
RIM - Net Present Value	$0.02	$2.52
RIM - Levelized Cost	$0 2436/kWh	$0.2207/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
TRC - Present Value of Benefits	$26.62	$26.62
TRC - Present Value of Costs	$8.20	$5.70
TRC - Benefit/Cost Ratio	3.25	4.7
TRC - Net Present Value	$18.42	$20.92
TRC - Levelized Cost	$0.0751/kWh	$0.0522/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
PAC - Present Value of Benefits	$26.62	$26.62
PAC - Present Value of Costs	$6.50	$4.00
PAC - Benefit/Cost Ratio	4.1	6.7
PAC - Net Present Value	$20.12	$22.62
PAC - Levelized Cost	$0.0595/kWh	$0.0366/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM892

Inputs - Measure Considerations

Measure Name: Gov. Typical High-Performance New Building - 25% Better	
Incentive Amount:	$0.90 /ft2
Measure/Project Cost:	$2.00 /ft2
Gross Consumption Savings:	6 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	6 kWh/yr
Gross Demand Savings:	0.00 kW/ft2
Gross Demand Savings w/ T&D losses:	0.00 kW
Participant's Savings on Year 1:	$1.26
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	82%
Suggested Program Cost (% of Incentive):	82%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	8.56
PC - Net Present Value	$15.13
PC - Levelized Cost	$0.0304/kWh
Simple Payback w/ Incentive (yr)	0.9 yr
RIM - Benefit/Cost Ratio	*0.98*
RIM - Net Present Value	*-$0.41*
RIM - Levelized Cost	*$0.2498/kWh*
TRC - Benefit/Cost Ratio	6.32
TRC - Net Present Value	$14.00
TRC - Levelized Cost	$0.0386/kWh
PAC - Benefit/Cost Ratio	*10.18*
PAC - Net Present Value	*$15.00*
PAC - Levelized Cost	*$0.0239/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$8.17*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*2.21*
RIM-YEC - Net Present Value	*$9.88*
RIM-YEC - Levelized Cost	*$0.1111/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$2.00
Incentive Amount in Year 1	$0.90
Assumed Program Administration Costs in Year 1	$0.73
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16.23	$16.23
Discounted Cumulative Gross Energy Savings for 20 years	66 kWh	66 kWh
PC - Present Value of Benefits	$17.13	$17.13
PC - Present Value of Costs	$2.00	$2.00
PC - Benefit/Cost Ratio	8.56	8.56
PC - Net Present Value	$15.13	$15.13
PC - Levelized Cost	$0.0304/kWh	$0.0304/kWh
Simple Payback with Incentive	0 9 yr	0.9 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$15.41	$15.41
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
RIM - Present Value of Benefits	$16.64	$16.64
RIM - Present Value of Costs	$17.05	$16.31
RIM - Benefit/Cost Ratio	1.0	1.0
RIM - Net Present Value	-$0.41	$0.32
RIM - Levelized Cost	$0 2498/kWh	$0.2391/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
TRC - Present Value of Benefits	$16.64	$16.64
TRC - Present Value of Costs	$2.63	$1.90
TRC - Benefit/Cost Ratio	6.32	8.8
TRC - Net Present Value	$14.00	$14.74
TRC - Levelized Cost	$0.0386/kWh	$0.0278/kWh

Program Administrator Cost Test from YEC Perspective (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$16.64	$16.64
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	68 kWh	68 kWh
PAC - Present Value of Benefits	$16.64	$16.64
PAC - Present Value of Costs	$1.63	$0.90
PAC - Benefit/Cost Ratio	10.2	18 5
PAC - Net Present Value	$15.00	$15.74
PAC - Levelized Cost	$0.0239/kWh	$0.0132/kWh

Energy Conservation Measure - Justification of the Incentive Level

Warning to analysts: This worksheet is connected to Government Rate Data

ECM902

Inputs - Measure Considerations

Measure Name: Gov. Typical High-Performance New Building - 40% Better	
Incentive Amount:	$2.40 /ft2
Measure/Project Cost:	$6.00 /ft2
Gross Consumption Savings:	9 kWh/ft2/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	10 kWh/yr
Gross Demand Savings:	0.00 kW/ft2
Gross Demand Savings w/ T&D losses:	0.00 kW
Participant's Savings on Year 1:	$2.01
Measure Lifetime:	20 yr

Inputs - Program Considerations

Program Cost (% of Incentive):	82%
Suggested Program Cost (% of Incentive):	82%
Forecasted Freeridership:	10%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	5%
Forecasted Rebound Effects:	0%

Outputs with Program Costs

PC - Benefit/Cost Ratio	4.73
PC - Net Present Value	$22.36
PC - Levelized Cost	$0.0569/kWh
Simple Payback w/ Incentive (yr)	1.8 yr
RIM - Benefit/Cost Ratio	*0.92*
RIM - Net Present Value	*-$2.40*
RIM - Levelized Cost	*$0.2658/kWh*
TRC - Benefit/Cost Ratio	3.48
TRC - Net Present Value	$18.96
TRC - Levelized Cost	$0.0701/kWh
PAC - Benefit/Cost Ratio	*6.11*
PAC - Net Present Value	*$22.26*
PAC - Levelized Cost	*$0.0399/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.43*
RIM-YECL - Net Present Value	*-$13.07*
RIM-YECL - Levelized Cost	*$0.2245/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.95*
RIM-YEC - Net Present Value	*$14.07*
RIM-YEC - Levelized Cost	*$0.1259/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$6.00
Incentive Amount in Year 1	$2.40
Assumed Program Administration Costs in Year 1	$1.96
Assumed Net-to-gross Ratio	95%

NTG = 1 - Freeridership P. Spi lover N.-p. Sp llover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$25.96	$25.96
Discounted Cumulative Gross Energy Savings for 20 years	105 kWh	105 kWh
PC - Present Value of Benefits	$28.36	$28.36
PC - Present Value of Costs	$6.00	$6.00
PC - Benefit/Cost Ratio	4.73	4.73
PC - Net Present Value	$22.36	$22.36
PC - Levelized Cost	$0.0569/kWh	$0.0569/kWh
Simple Payback with Incentive	1.8 yr	1.8 yr

Ratepayer Impact Measure Test from YEC Perspective (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$24.66	$24.66
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
RIM - Present Value of Benefits	$26.62	$26.62
RIM - Present Value of Costs	$29.02	$27.06
RIM - Benefit/Cost Ratio	0.9	1.0
RIM - Net Present Value	-$2.40	-$0.45
RIM - Levelized Cost	$0 2658/kWh	$0.2479/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
TRC - Present Value of Benefits	$26.62	$26.62
TRC - Present Value of Costs	$7.66	$5.70
TRC - Benefit/Cost Ratio	3.48	4.7
TRC - Net Present Value	$18.96	$20.92
TRC - Levelized Cost	$0.0701/kWh	$0.0522/kWh

Program Administrator Cost Test from YEC Perspective (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$26.62	$26.62
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	109 kWh	109 kWh
PAC - Present Value of Benefits	$26.62	$26.62
PAC - Present Value of Costs	$4.36	$2.40
PAC - Benefit/Cost Ratio	6.1	11.1
PAC - Net Present Value	$22.26	$24.22
PAC - Levelized Cost	$0.0399/kWh	$0.0220/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM24

Inputs - Measure Considerations	
Measure Name:	12W LED A19 Bulb
Incentive Amount:	$18.00
Measure/Project Cost:	$44.00
Gross Consumption Savings:	48 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	52 kWh/yr
Gross Demand Savings:	.017 kW
Gross Demand Savings w/ T&D losses:	.019 kW
Participant's Savings on Year 1:	$6.97
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	177%
Suggested Program Cost (% of Incentive):	177%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.45
PC - Net Present Value	$63.93
PC - Levelized Cost	$0.0825/kWh
Simple Payback w/ Incentive (yr)	3.7 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$7.15*
RIM - Levelized Cost	*$0.2326/kWh*
TRC - Benefit/Cost Ratio	1.94
TRC - Net Present Value	$75.67
TRC - Levelized Cost	$0.1255/kWh
PAC - Benefit/Cost Ratio	*3.13*
PAC - Net Present Value	*$106.07*
PAC - Levelized Cost	*$0.0779/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$34.47*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.52*
RIM-YEC - Net Present Value	*$58.11*
RIM-YEC - Levelized Cost	*$0.1612/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$44.00
Incentive Amount in Year 1	$18.00
Assumed Program Administration Costs in Year 1	$31.84
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$89.93	$89.93
Discounted Cumulative Gross Energy Savings for 20 years	533 kWh	533 kWh
PC - Present Value of Benefits	$107.93	$107.93
PC - Present Value of Costs	$44.00	$44.00
PC - Benefit/Cost Ratio	2.45	2.45
PC - Net Present Value	$63.93	$63.93
PC - Levelized Cost	$0.0825/kWh	$0.0825/kWh
Simple Payback with Incentive	3.7 yr	3.7 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$98.92	$98.92
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
RIM - Present Value of Benefits	$155.92	$155.92
RIM - Present Value of Costs	$148.77	$116.92
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$7.15	$38.99
RIM - Levelized Cost	$0 2326/kWh	$0.1828/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
TRC - Present Value of Benefits	$155.92	$155.92
TRC - Present Value of Costs	$80.24	$48.40
TRC - Benefit/Cost Ratio	1.94	3 2
TRC - Net Present Value	$75.67	$107.52
TRC - Levelized Cost	$0.1255/kWh	$0.0757/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$155.92	$155.92
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	640 kWh	640 kWh
PAC - Present Value of Benefits	$155.92	$155.92
PAC - Present Value of Costs	$49.84	$18.00
PAC - Benefit/Cost Ratio	3.1	8.7
PAC - Net Present Value	$106.07	$137.92
PAC - Levelized Cost	$0.0779/kWh	$0.0281/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM60

Inputs - Measure Considerations	
Measure Name:	8W LED A19 Bulb
Incentive Amount:	$12.00
Measure/Project Cost:	$30.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.65
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	177%
Suggested Program Cost (% of Incentive):	177%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.40
PC - Net Present Value	$41.95
PC - Levelized Cost	$0.0844/kWh
Simple Payback w/ Incentive (yr)	3.9 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$4.76*
RIM - Levelized Cost	*$0.2326/kWh*
TRC - Benefit/Cost Ratio	1.92
TRC - Net Present Value	$49.71
TRC - Levelized Cost	$0.1272/kWh
PAC - Benefit/Cost Ratio	*3.13*
PAC - Net Present Value	*$70.71*
PAC - Levelized Cost	*$0.0779/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$22.98*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.52*
RIM-YEC - Net Present Value	*$38.74*
RIM-YEC - Levelized Cost	*$0.1612/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$30.00
Incentive Amount in Year 1	$12.00
Assumed Program Administration Costs in Year 1	$21.23
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$59.95	$59.95
Discounted Cumulative Gross Energy Savings for 20 years	355 kWh	355 kWh
PC - Present Value of Benefits	$71.95	$71.95
PC - Present Value of Costs	$30.00	$30.00
PC - Benefit/Cost Ratio	2.40	2.40
PC - Net Present Value	$41.95	$41.95
PC - Levelized Cost	$0.0844/kWh	$0.0844/kWh
Simple Payback with Incentive	3 9 yr	3.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$65.95	$65.95
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
RIM - Present Value of Benefits	$103.94	$103.94
RIM - Present Value of Costs	$99.18	$77.95
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$4.76	$25.99
RIM - Levelized Cost	$0 2326/kWh	$0.1828/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
TRC - Present Value of Benefits	$103.94	$103.94
TRC - Present Value of Costs	$54.23	$33.00
TRC - Benefit/Cost Ratio	1.92	3.1
TRC - Net Present Value	$49.71	$70.94
TRC - Levelized Cost	$0.1272/kWh	$0.0774/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$103.94	$103.94
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	426 kWh	426 kWh
PAC - Present Value of Benefits	$103.94	$103.94
PAC - Present Value of Costs	$33.23	$12.00
PAC - Benefit/Cost Ratio	3.1	8.7
PAC - Net Present Value	$70.71	$91.94
PAC - Levelized Cost	$0.0779/kWh	$0.0281/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations	
Measure Name:	LED MR16 Bulbs
Incentive Amount:	$10.00
Measure/Project Cost:	$20.00
Gross Consumption Savings:	15 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	16 kWh/yr
Gross Demand Savings:	.005 kW
Gross Demand Savings w/ T&D losses:	.006 kW
Participant's Savings on Year 1:	$2.18
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	100%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.91
PC - Net Present Value	$18.10
PC - Levelized Cost	$0.1200/kWh
Simple Payback w/ Incentive (yr)	4.6 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$2.14*
RIM - Levelized Cost	*$0.2545/kWh*
TRC - Benefit/Cost Ratio	1.52
TRC - Net Present Value	$16.77
TRC - Levelized Cost	$0.1599/kWh
PAC - Benefit/Cost Ratio	*2.44*
PAC - Net Present Value	*$28.77*
PAC - Levelized Cost	*$0.0998/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$10.77*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.35*
RIM-YEC - Net Present Value	*$13.79*
RIM-YEC - Levelized Cost	*$0.1814/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$20.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$9.95
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$28.10	$28.10
Discounted Cumulative Gross Energy Savings for 20 years	167 kWh	167 kWh
PC - Present Value of Benefits	$38.10	$38.10
PC - Present Value of Costs	$20.00	$20.00
PC - Benefit/Cost Ratio	1.91	1.91
PC - Net Present Value	$18.10	$18.10
PC - Levelized Cost	$0.1200/kWh	$0.1200/kWh
Simple Payback with Incentive	4.6 yr	4.6 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$30.91	$30.91
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
RIM - Present Value of Benefits	$48.72	$48.72
RIM - Present Value of Costs	$50.87	$40.91
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	-$2.14	$7.81
RIM - Levelized Cost	$0 2545/kWh	$0.2047/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
TRC - Present Value of Benefits	$48.72	$48.72
TRC - Present Value of Costs	$31.95	$22.00
TRC - Benefit/Cost Ratio	1.52	2 2
TRC - Net Present Value	$16.77	$26.72
TRC - Levelized Cost	$0.1599/kWh	$0.1101/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$48.72	$48.72
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	200 kWh	200 kWh
PAC - Present Value of Benefits	$48.72	$48.72
PAC - Present Value of Costs	$19.95	$10.00
PAC - Benefit/Cost Ratio	2.4	4 9
PAC - Net Present Value	$28.77	$38.72
PAC - Levelized Cost	$0.0998/kWh	$0.0500/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM62

Inputs - Measure Considerations	
Measure Name:	LED PAR30 Bulbs
Incentive Amount:	$20.00
Measure/Project Cost:	$51.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	.016 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	133%
Suggested Program Cost (% of Incentive):	133%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.86
PC - Net Present Value	$43.94
PC - Levelized Cost	$0.1148/kWh
Simple Payback w/ Incentive (yr)	5.3 yr
RIM - Benefit/Cost Ratio	*1.01*
RIM - Net Present Value	*$0.95*
RIM - Levelized Cost	*$0.2420/kWh*
TRC - Benefit/Cost Ratio	1.57
TRC - Net Present Value	$47.29
TRC - Levelized Cost	$0.1551/kWh
PAC - Benefit/Cost Ratio	*2.79*
PAC - Net Present Value	*$83.39*
PAC - Levelized Cost	*$0.0873/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.72*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.44*
RIM-YEC - Net Present Value	*$43.43*
RIM-YEC - Levelized Cost	*$0.1698/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$51.00
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$26.54
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.94	$74.94
Discounted Cumulative Gross Energy Savings for 20 years	444 kWh	444 kWh
PC - Present Value of Benefits	$94.94	$94.94
PC - Present Value of Costs	$51.00	$51.00
PC - Benefit/Cost Ratio	1.86	1.86
PC - Net Present Value	$43.94	$43.94
PC - Levelized Cost	$0.1148/kWh	$0.1148/kWh
Simple Payback with Incentive	5 3 yr	5.3 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$82.44	$82.44
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
RIM - Present Value of Benefits	$129.93	$129.93
RIM - Present Value of Costs	$128.97	$102.44
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	$0.95	$27.49
RIM - Levelized Cost	$0 2420/kWh	$0.1922/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
TRC - Present Value of Benefits	$129.93	$129.93
TRC - Present Value of Costs	$82.64	$56.10
TRC - Benefit/Cost Ratio	1.57	2 3
TRC - Net Present Value	$47.29	$73.83
TRC - Levelized Cost	$0.1551/kWh	$0.1053/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$129.93	$129.93
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	533 kWh	533 kWh
PAC - Present Value of Benefits	$129.93	$129.93
PAC - Present Value of Costs	$46.54	$20.00
PAC - Benefit/Cost Ratio	2.8	6 5
PAC - Net Present Value	$83.39	$109.93
PAC - Levelized Cost	$0.0873/kWh	$0.0375/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM63

Inputs - Measure Considerations	
Measure Name:	LED PAR38 Bulbs
Incentive Amount:	$20.00
Measure/Project Cost:	$43.00
Gross Consumption Savings:	55 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	60 kWh/yr
Gross Demand Savings:	.02 kW
Gross Demand Savings w/ T&D losses:	.021 kW
Participant's Savings on Year 1:	$7.99
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	182%
Suggested Program Cost (% of Incentive):	182%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	10%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.86
PC - Net Present Value	$80.05
PC - Levelized Cost	$0.0704/kWh
Simple Payback w/ Incentive (yr)	2.9 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$8.81*
RIM - Levelized Cost	*$0.2318/kWh*
TRC - Benefit/Cost Ratio	2.13
TRC - Net Present Value	$94.86
TRC - Levelized Cost	$0.1143/kWh
PAC - Benefit/Cost Ratio	*3.16*
PAC - Net Present Value	*$122.16*
PAC - Levelized Cost	*$0.0771/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$39.49*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.53*
RIM-YEC - Net Present Value	*$67.21*
RIM-YEC - Levelized Cost	*$0.1604/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$43.00
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$36.49
Assumed Net-to-gross Ratio	110%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$103.05	$103.05
Discounted Cumulative Gross Energy Savings for 20 years	611 kWh	611 kWh
PC - Present Value of Benefits	$123.05	$123.05
PC - Present Value of Costs	$43.00	$43.00
PC - Benefit/Cost Ratio	2.86	2.86
PC - Net Present Value	$80.05	$80.05
PC - Levelized Cost	$0.0704/kWh	$0.0704/kWh
Simple Payback with Incentive	2 9 yr	2.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$113.35	$113.35
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
RIM - Present Value of Benefits	$178.65	$178.65
RIM - Present Value of Costs	$169.84	$133.35
RIM - Benefit/Cost Ratio	1.1	1 3
RIM - Net Present Value	$8.81	$45.30
RIM - Levelized Cost	$0 2318/kWh	$0.1820/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
TRC - Present Value of Benefits	$178.65	$178.65
TRC - Present Value of Costs	$83.79	$47.30
TRC - Benefit/Cost Ratio	2.13	3.8
TRC - Net Present Value	$94.86	$131.35
TRC - Levelized Cost	$0.1143/kWh	$0.0645/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$178.65	$178.65
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	733 kWh	733 kWh
PAC - Present Value of Benefits	$178.65	$178.65
PAC - Present Value of Costs	$56.49	$20.00
PAC - Benefit/Cost Ratio	3.2	8 9
PAC - Net Present Value	$122.16	$158.65
PAC - Levelized Cost	$0.0771/kWh	$0.0273/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM44

Inputs - Measure Considerations	
Measure Name:	Spot or Task Lighting
Incentive Amount:	$10.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	.016 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	96%
Suggested Program Cost (% of Incentive):	96%
Forecasted Freeridership:	20%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.27
PC - Net Present Value	$31.76
PC - Levelized Cost	$0.0841/kWh
Simple Payback w/ Incentive (yr)	2.6 yr
RIM - Benefit/Cost Ratio	*1.03*
RIM - Net Present Value	*$1.90*
RIM - Levelized Cost	*$0.2200/kWh*
TRC - Benefit/Cost Ratio	1.99
TRC - Net Present Value	$29.31
TRC - Levelized Cost	$0.1143/kWh
PAC - Benefit/Cost Ratio	*3.00*
PAC - Net Present Value	*$39.31*
PAC - Levelized Cost	*$0.0758/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$13.53*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$19.58*
RIM-YEC - Levelized Cost	*$0.1553/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$10.00
Assumed Program Administration Costs in Year 1	$9.65
Assumed Net-to-gross Ratio	80%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$46.76	$46.76
Discounted Cumulative Gross Energy Savings for 10 years	297 kWh	297 kWh
PC - Present Value of Benefits	$56.76	$56.76
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.27	2.27
PC - Net Present Value	$31.76	$31.76
PC - Levelized Cost	$0.0841/kWh	$0.0841/kWh
Simple Payback with Incentive	2.6 yr	2.6 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$37.41	$37.41
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
RIM - Present Value of Benefits	$58.96	$58.96
RIM - Present Value of Costs	$57.06	$47.41
RIM - Benefit/Cost Ratio	1.0	1 2
RIM - Net Present Value	$1.90	$11.55
RIM - Levelized Cost	$0 2200/kWh	$0.1828/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
TRC - Present Value of Benefits	$58.96	$58.96
TRC - Present Value of Costs	$29.65	$20.00
TRC - Benefit/Cost Ratio	1.99	2 9
TRC - Net Present Value	$29.31	$38.96
TRC - Levelized Cost	$0.1143/kWh	$0.0771/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$58.96	$58.96
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	259 kWh	259 kWh
PAC - Present Value of Benefits	$58.96	$58.96
PAC - Present Value of Costs	$19.65	$10.00
PAC - Benefit/Cost Ratio	3.0	5 9
PAC - Net Present Value	$39.31	$48.96
PAC - Levelized Cost	$0.0758/kWh	$0.0386/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM151

Inputs - Measure Considerations	
Measure Name:	Block Heater Timer
Incentive Amount:	$20.00
Measure/Project Cost:	$37.50
Gross Consumption Savings:	130 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	142 kWh/yr
Gross Demand Savings:	0.05 kW
Gross Demand Savings w/ T&D losses:	0.05 kW
Participant's Savings on Year 1:	$18.86
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	378%
Suggested Program Cost (% of Incentive):	378%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.58
PC - Net Present Value	$134.24
PC - Levelized Cost	$0.0389/kWh
Simple Payback w/ Incentive (yr)	0.9 yr
RIM - Benefit/Cost Ratio	*0.97*
RIM - Net Present Value	*-$8.20*
RIM - Levelized Cost	*$0.2351/kWh*
TRC - Benefit/Cost Ratio	2.11
TRC - Net Present Value	$126.05
TRC - Levelized Cost	$0.1075/kWh
PAC - Benefit/Cost Ratio	*2.50*
PAC - Net Present Value	*$143.55*
PAC - Levelized Cost	*$0.0909/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$54.89*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.34*
RIM-YEC - Net Present Value	*$63.49*
RIM-YEC - Levelized Cost	*$0.1698/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.50
Incentive Amount in Year 1	$20.00
Assumed Program Administration Costs in Year 1	$75.62
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$151.74	$151.74
Discounted Cumulative Gross Energy Savings for 10 years	965 kWh	965 kWh
PC - Present Value of Benefits	$171.74	$171.74
PC - Present Value of Costs	$37.50	$37.50
PC - Benefit/Cost Ratio	4.58	4.58
PC - Net Present Value	$134.24	$134.24
PC - Levelized Cost	$0.0389/kWh	$0.0389/kWh
Simple Payback with Incentive	0 9 yr	0.9 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$151.74	$151.74
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
RIM - Present Value of Benefits	$239.16	$239.16
RIM - Present Value of Costs	$247.36	$171.74
RIM - Benefit/Cost Ratio	1.0	1.4
RIM - Net Present Value	-$8.20	$67.42
RIM - Levelized Cost	$0 2351/kWh	$0.1632/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
TRC - Present Value of Benefits	$239.16	$239.16
TRC - Present Value of Costs	$113.12	$37.50
TRC - Benefit/Cost Ratio	2.11	6.4
TRC - Net Present Value	$126.05	$201.66
TRC - Levelized Cost	$0.1075/kWh	$0.0356/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
PAC - Present Value of Benefits	$239.16	$239.16
PAC - Present Value of Costs	$95.62	$20.00
PAC - Benefit/Cost Ratio	2.5	12.0
PAC - Net Present Value	$143.55	$219.16
PAC - Levelized Cost	$0.0909/kWh	$0.0190/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM091

Inputs - Measure Considerations	
Measure Name:	Ed. Ultra Low-flow Showerheads
Incentive Amount:	$0.00
Measure/Project Cost:	$8.62
Gross Consumption Savings:	325 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	354 kWh/yr
Gross Demand Savings:	.116 kW
Gross Demand Savings w/ T&D losses:	.126 kW
Participant's Savings on Year 1:	$47.22
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit	$193.78
Suggested Program Cost ($ per Unit):	$193.78
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	44.08
PC - Net Present Value	$371.34
PC - Levelized Cost	$0.0036/kWh
Simple Payback w/ Incentive (yr)	0.2 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$25.12*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	2.96
TRC - Net Present Value	$396.46
TRC - Levelized Cost	$0.0768/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$405.08*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$137.43*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$204.61*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8.62
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$193.78
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$379.96	$379.96
Discounted Cumulative Gross Energy Savings for 10 years	2,416 kWh	2,416 kWh
PC - Present Value of Benefits	$379.96	$379.96
PC - Present Value of Costs	$8.62	$8.62
PC - Benefit/Cost Ratio	44.08	44.08
PC - Net Present Value	$371.34	$371.34
PC - Levelized Cost	$0.0036/kWh	$0.0036/kWh
Simple Payback with Incentive	0 2 yr	0.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$379.96	$379.96
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
RIM - Present Value of Benefits	$598.86	$598.86
RIM - Present Value of Costs	$573.74	$379.96
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$25.12	$218.90
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
TRC - Present Value of Benefits	$598.86	$598.86
TRC - Present Value of Costs	$202.40	$8.62
TRC - Benefit/Cost Ratio	2.96	69 5
TRC - Net Present Value	$396.46	$590.24
TRC - Levelized Cost	$0.0768/kWh	$0.0033/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
PAC - Present Value of Benefits	$598.86	$598.86
PAC - Present Value of Costs	$193.78	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$405.08	$598.86
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM111

Inputs - Measure Considerations	
Measure Name:	Ed. Smart, Surge Protected Power Bars for PCs and TVs
Incentive Amount:	$0.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	68 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	74 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.85
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit	$40.41
Suggested Program Cost ($ per Unit):	$40.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.17
PC - Net Present Value	$54.24
PC - Levelized Cost	$0.0496/kWh
Simple Payback w/ Incentive (yr)	2.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.24*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	1.91
TRC - Net Present Value	$59.48
TRC - Levelized Cost	$0.1191/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$84.48*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.66*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$42.67*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$40.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$79.24	$79.24
Discounted Cumulative Gross Energy Savings for 10 years	504 kWh	504 kWh
PC - Present Value of Benefits	$79.24	$79.24
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	3.17	3.17
PC - Net Present Value	$54.24	$54.24
PC - Levelized Cost	$0.0496/kWh	$0.0496/kWh
Simple Payback with Incentive	2 5 yr	2.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$79.24	$79.24
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
RIM - Present Value of Benefits	$124.89	$124.89
RIM - Present Value of Costs	$119.66	$79.24
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.24	$45.65
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
TRC - Present Value of Benefits	$124.89	$124.89
TRC - Present Value of Costs	$65.41	$25.00
TRC - Benefit/Cost Ratio	1.91	5.0
TRC - Net Present Value	$59.48	$99.89
TRC - Levelized Cost	$0.1191/kWh	$0.0455/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
PAC - Present Value of Benefits	$124.89	$124.89
PAC - Present Value of Costs	$40.41	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$84.48	$124.89
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM181

Inputs - Measure Considerations	
Measure Name:	Ed. DHW Tank Insulation
Incentive Amount:	$0.00
Measure/Project Cost:	$37.58
Gross Consumption Savings:	62 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	68 kWh/yr
Gross Demand Savings:	.022 kW
Gross Demand Savings w/ T&D losses:	.024 kW
Participant's Savings on Year 1:	$9.01
Measure Lifetime:	14 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$51.75
Suggested Program Cost ($ per Unit):	$51.75
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.47
PC - Net Present Value	$55.06
PC - Levelized Cost	$0.0658/kWh
Simple Payback w/ Incentive (yr)	4.2 yr
RIM - Benefit/Cost Ratio	*1.01*
RIM - Net Present Value	*$1.62*
RIM - Levelized Cost	*$0.2317/kWh*
TRC - Benefit/Cost Ratio	1.63
TRC - Net Present Value	$56.68
TRC - Levelized Cost	$0.1433/kWh
PAC - Benefit/Cost Ratio	*2.82*
PAC - Net Present Value	*$94.26*
PAC - Levelized Cost	*$0.0830/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$32.97*
RIM-YECL - Levelized Cost	*$0.1482/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.44*
RIM-YEC - Net Present Value	*$47.04*
RIM-YEC - Levelized Cost	*$0.1637/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.58
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$51.75
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 14 years	$92.64	$92.64
Discounted Cumulative Gross Energy Savings for 14 years	571 kWh	571 kWh
PC - Present Value of Benefits	$92.64	$92.64
PC - Present Value of Costs	$37.58	$37.58
PC - Benefit/Cost Ratio	2.47	2.47
PC - Net Present Value	$55.06	$55.06
PC - Levelized Cost	$0.0658/kWh	$0.0658/kWh
Simple Payback with Incentive	4 2 yr	4.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Present Value of Lost Revenues for 14 years	$92.64	$92.64
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
RIM - Present Value of Benefits	$146.01	$146.01
RIM - Present Value of Costs	$144.40	$92.64
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$1.62	$53.37
RIM - Levelized Cost	$0 2317/kWh	$0.1487/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
TRC - Present Value of Benefits	$146.01	$146.01
TRC - Present Value of Costs	$89.33	$37.58
TRC - Benefit/Cost Ratio	1.63	3 9
TRC - Net Present Value	$56.68	$108.43
TRC - Levelized Cost	$0.1433/kWh	$0.0603/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
PAC - Present Value of Benefits	$146.01	$146.01
PAC - Present Value of Costs	$51.75	$0.00
PAC - Benefit/Cost Ratio	2.8	#DIV/0!
PAC - Net Present Value	$94.26	$146.01
PAC - Levelized Cost	$0.0830/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM201

Inputs - Measure Considerations	
Measure Name:	Ed. DHW Pipe Insulation
Incentive Amount:	$0.00
Measure/Project Cost:	$0.79
Gross Consumption Savings:	34 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	37 kWh/yr
Gross Demand Savings:	.012 kW
Gross Demand Savings w/ T&D losses:	.013 kW
Participant's Savings on Year 1:	$4.94
Measure Lifetime:	15 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$30.41
Suggested Program Cost ($ per Unit):	$30.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	67.39
PC - Net Present Value	$52.44
PC - Levelized Cost	$0.0024/kWh
Simple Payback w/ Incentive (yr)	0.2 yr
RIM - Benefit/Cost Ratio	*1.00*
RIM - Net Present Value	*$0.26*
RIM - Levelized Cost	*$0.2352/kWh*
TRC - Benefit/Cost Ratio	2.69
TRC - Net Present Value	$52.70
TRC - Levelized Cost	$0.0877/kWh
PAC - Benefit/Cost Ratio	*2.76*
PAC - Net Present Value	*$53.49*
PAC - Levelized Cost	*$0.0855/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$18.88*
RIM-YECL - Levelized Cost	*$0.1492/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.42*
RIM-YEC - Net Present Value	*$26.59*
RIM-YEC - Levelized Cost	*$0.1664/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.79
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$30.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 15 years	$53.23	$53.23
Discounted Cumulative Gross Energy Savings for 15 years	326 kWh	326 kWh
PC - Present Value of Benefits	$53.23	$53.23
PC - Present Value of Costs	$0.79	$0.79
PC - Benefit/Cost Ratio	67.39	67.39
PC - Net Present Value	$52.44	$52.44
PC - Levelized Cost	$0.0024/kWh	$0.0024/kWh
Simple Payback with Incentive	0 2 yr	0.2 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Present Value of Lost Revenues for 15 years	$53.23	$53.23
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
RIM - Present Value of Benefits	$83.90	$83.90
RIM - Present Value of Costs	$83.64	$53.23
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$0.26	$30.67
RIM - Levelized Cost	$0 2352/kWh	$0.1497/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
TRC - Present Value of Benefits	$83.90	$83.90
TRC - Present Value of Costs	$31.20	$0.79
TRC - Benefit/Cost Ratio	2.69	106 2
TRC - Net Present Value	$52.70	$83.11
TRC - Levelized Cost	$0.0877/kWh	$0.0022/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
PAC - Present Value of Benefits	$83.90	$83.90
PAC - Present Value of Costs	$30.41	$0.00
PAC - Benefit/Cost Ratio	2.8	#DIV/0!
PAC - Net Present Value	$53.49	$83.90
PAC - Levelized Cost	$0.0855/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM481

Inputs - Measure Considerations	
Measure Name:	Ed. Motion Detectors - Indoor and Outdoor
Incentive Amount:	$0.00
Measure/Project Cost:	$22.94
Gross Consumption Savings:	66 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	72 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.59
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$39.35
Suggested Program Cost ($ per Unit):	$39.35
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.36
PC - Net Present Value	$54.21
PC - Levelized Cost	$0.0468/kWh
Simple Payback w/ Incentive (yr)	2.4 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.10*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	1.95
TRC - Net Present Value	$59.31
TRC - Levelized Cost	$0.1164/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$82.25*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$27.90*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$41.55*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$22.94
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$39.35
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$77.15	$77.15
Discounted Cumulative Gross Energy Savings for 10 years	490 kWh	490 kWh
PC - Present Value of Benefits	$77.15	$77.15
PC - Present Value of Costs	$22.94	$22.94
PC - Benefit/Cost Ratio	3.36	3.36
PC - Net Present Value	$54.21	$54.21
PC - Levelized Cost	$0.0468/kWh	$0.0468/kWh
Simple Payback with Incentive	2.4 yr	2.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$77.15	$77.15
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
RIM - Present Value of Benefits	$121.60	$121.60
RIM - Present Value of Costs	$116.50	$77.15
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.10	$44.45
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
TRC - Present Value of Benefits	$121.60	$121.60
TRC - Present Value of Costs	$62.28	$22.94
TRC - Benefit/Cost Ratio	1.95	5 3
TRC - Net Present Value	$59.31	$98.66
TRC - Levelized Cost	$0.1164/kWh	$0.0429/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
PAC - Present Value of Benefits	$121.60	$121.60
PAC - Present Value of Costs	$39.35	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$82.25	$121.60
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM141

Inputs - Measure Considerations	
Measure Name:	Ed. Prog. Thermostats (Central)
Incentive Amount:	$0.00
Measure/Project Cost:	$62.50
Gross Consumption Savings:	827 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	902 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.322 kW
Participant's Savings on Year 1:	$120.16
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$542.41
Suggested Program Cost ($ per Unit):	$542.41
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	16.63
PC - Net Present Value	$976.76
PC - Levelized Cost	$0.0095/kWh
Simple Payback w/ Incentive (yr)	0.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$56.31*
RIM - Levelized Cost	*$0.2212/kWh*
TRC - Benefit/Cost Ratio	2.71
TRC - Net Present Value	$1,033.07
TRC - Levelized Cost	$0.0846/kWh
PAC - Benefit/Cost Ratio	*3.02*
PAC - Net Present Value	*$1,095.57*
PAC - Levelized Cost	*$0.0759/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$374.34*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$552.01*
RIM-YEC - Levelized Cost	*$0.1557/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$62.50
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$542.41
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,039 26	$1,039.26
Discounted Cumulative Gross Energy Savings for 11 years	6,556 kWh	6,556 kWh
PC - Present Value of Benefits	$1,039.26	$1,039.26
PC - Present Value of Costs	$62.50	$62.50
PC - Benefit/Cost Ratio	16.63	16.63
PC - Net Present Value	$976.76	$976.76
PC - Levelized Cost	$0.0095/kWh	$0.0095/kWh
Simple Payback with Incentive	0 5 yr	0.5 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,039.26	$1,039.26
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
RIM - Present Value of Benefits	$1,637.98	$1,637.98
RIM - Present Value of Costs	$1,581.66	$1,039.26
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$56.31	$598.72
RIM - Levelized Cost	$0 2212/kWh	$0.1454/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
TRC - Present Value of Benefits	$1,637.98	$1,637.98
TRC - Present Value of Costs	$604.91	$62.50
TRC - Benefit/Cost Ratio	2.71	26 2
TRC - Net Present Value	$1,033.07	$1,575.48
TRC - Levelized Cost	$0.0846/kWh	$0.0087/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
PAC - Present Value of Benefits	$1,637.98	$1,637.98
PAC - Present Value of Costs	$542.41	$0.00
PAC - Benefit/Cost Ratio	3.0	#DIV/0!
PAC - Net Present Value	$1,095.57	$1,637.98
PAC - Levelized Cost	$0.0759/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM211

Inputs - Measure Considerations	
Measure Name:	Ed. Prog. Thermostats
Incentive Amount:	$0.00
Measure/Project Cost:	$285.43
Gross Consumption Savings:	826 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	901 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.321 kW
Participant's Savings on Year 1:	$120.02
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$541.75
Suggested Program Cost ($ per Unit):	$541.75
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.64
PC - Net Present Value	$752.57
PC - Levelized Cost	$0.0436/kWh
Simple Payback w/ Incentive (yr)	2.4 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$56.25*
RIM - Levelized Cost	*$0.2212/kWh*
TRC - Benefit/Cost Ratio	1.98
TRC - Net Present Value	$808.82
TRC - Levelized Cost	$0.1158/kWh
PAC - Benefit/Cost Ratio	*3.02*
PAC - Net Present Value	*$1,094.25*
PAC - Levelized Cost	*$0.0759/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$373.89*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.47*
RIM-YEC - Net Present Value	*$551.34*
RIM-YEC - Levelized Cost	*$0.1557/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$285.43
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$541.75
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Gross Energy Savings for 11 years	6,548 kWh	6,548 kWh
PC - Present Value of Benefits	$1,038.00	$1,038.00
PC - Present Value of Costs	$285.43	$285.43
PC - Benefit/Cost Ratio	3.64	3.64
PC - Net Present Value	$752.57	$752.57
PC - Levelized Cost	$0.0436/kWh	$0.0436/kWh
Simple Payback with Incentive	2.4 yr	2.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
RIM - Present Value of Benefits	$1,636.00	$1,636.00
RIM - Present Value of Costs	$1,579.75	$1,038.00
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$56.25	$598.00
RIM - Levelized Cost	$0 2212/kWh	$0.1454/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
TRC - Present Value of Benefits	$1,636.00	$1,636.00
TRC - Present Value of Costs	$827.18	$285.43
TRC - Benefit/Cost Ratio	1.98	5.7
TRC - Net Present Value	$808.82	$1,350.57
TRC - Levelized Cost	$0.1158/kWh	$0.0400/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
PAC - Present Value of Benefits	$1,636.00	$1,636.00
PAC - Present Value of Costs	$541.75	$0.00
PAC - Benefit/Cost Ratio	3.0	#DIV/0!
PAC - Net Present Value	$1,094.25	$1,636.00
PAC - Levelized Cost	$0.0759/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM061

Inputs - Measure Considerations	
Measure Name:	Ed. E-Star TVs
Incentive Amount:	$0.00
Measure/Project Cost:	$125.00
Gross Consumption Savings:	69 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	75 kWh/yr
Gross Demand Savings:	.025 kW
Gross Demand Savings w/ T&D losses:	.027 kW
Participant's Savings on Year 1:	$10.03
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$41.14
Suggested Program Cost ($ per Unit):	$41.14
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.65
PC - Net Present Value	-$44.33
PC - Levelized Cost	$0.2437/kWh
Simple Payback w/ Incentive (yr)	12.5 yr
RIM - Benefit/Cost Ratio	*1.04*
RIM - Net Present Value	*$5.33*
RIM - Levelized Cost	*$0.2178/kWh*
TRC - Benefit/Cost Ratio	0.77
TRC - Net Present Value	-$39.00
TRC - Levelized Cost	$0.2971/kWh
PAC - Benefit/Cost Ratio	*3.09*
PAC - Net Present Value	*$86.00*
PAC - Levelized Cost	*$0.0736/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$29.18*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.49*
RIM-YEC - Net Present Value	*$43.44*
RIM-YEC - Levelized Cost	*$0.1531/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$125.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$41.14
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$80.67	$80.67
Discounted Cumulative Gross Energy Savings for 10 years	513 kWh	513 kWh
PC - Present Value of Benefits	$80.67	$80.67
PC - Present Value of Costs	$125.00	$125.00
PC - Benefit/Cost Ratio	0.65	0.65
PC - Net Present Value	-$44.33	-$44.33
PC - Levelized Cost	$0 2437/kWh	$0.2437/kWh
Simple Payback with Incentive	12 5 yr	12.5 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$80.67	$80.67
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
RIM - Present Value of Benefits	$127.14	$127.14
RIM - Present Value of Costs	$121.81	$80.67
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$5.33	$46.47
RIM - Levelized Cost	$0 2178/kWh	$0.1442/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
TRC - Present Value of Benefits	$127.14	$127.14
TRC - Present Value of Costs	$166.14	$125.00
TRC - Benefit/Cost Ratio	0.77	1.0
TRC - Net Present Value	-$39.00	$2.14
TRC - Levelized Cost	$0 2971/kWh	$0.2235/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
PAC - Present Value of Benefits	$127.14	$127.14
PAC - Present Value of Costs	$41.14	$0.00
PAC - Benefit/Cost Ratio	3.1	#DIV/0!
PAC - Net Present Value	$86.00	$127.14
PAC - Levelized Cost	$0.0736/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM081

Inputs - Measure Considerations	
Measure Name:	Ed. ESTAR Printers and Fax
Incentive Amount:	$0.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.61
Measure Lifetime:	6 yr

Inputs - Program Considerations	
Program Cost Per Unit:	$11.36
Suggested Program Cost ($ per Unit):	$11.36
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.98
PC - Net Present Value	-$0.52
PC - Levelized Cost	$0.1554/kWh
Simple Payback w/ Incentive (yr)	5.4 yr
RIM - Benefit/Cost Ratio	*1.08*
RIM - Net Present Value	*$2.74*
RIM - Levelized Cost	*$0.2043/kWh*
TRC - Benefit/Cost Ratio	1.06
TRC - Net Present Value	$2.22
TRC - Levelized Cost	$0.2072/kWh
PAC - Benefit/Cost Ratio	*3.40*
PAC - Net Present Value	*$27.22*
PAC - Levelized Cost	*$0.0647/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.01*
RIM-YECL - Levelized Cost	*$0.1394/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.54*
RIM-YEC - Net Present Value	*$13.85*
RIM-YEC - Levelized Cost	*$0.1430/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$0.00
Assumed Program Administration Costs in Year 1	$11.36
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 6 years	$24.48	$24.48
Discounted Cumulative Gross Energy Savings for 6 years	161 kWh	161 kWh
PC - Present Value of Benefits	$24.48	$24.48
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	0.98	0.98
PC - Net Present Value	-$0.52	-$0.52
PC - Levelized Cost	$0.1554/kWh	$0.1554/kWh
Simple Payback with Incentive	5.4 yr	5.4 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Present Value of Lost Revenues for 6 years	$24.48	$24.48
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
RIM - Present Value of Benefits	$38.58	$38.58
RIM - Present Value of Costs	$35.84	$24.48
RIM - Benefit/Cost Ratio	1.1	1.6
RIM - Net Present Value	$2.74	$14.10
RIM - Levelized Cost	$0 2043/kWh	$0.1395/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
TRC - Present Value of Benefits	$38.58	$38.58
TRC - Present Value of Costs	$36.36	$25.00
TRC - Benefit/Cost Ratio	1.06	1 5
TRC - Net Present Value	$2.22	$13.58
TRC - Levelized Cost	$0 2072/kWh	$0.1425/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
PAC - Present Value of Benefits	$38.58	$38.58
PAC - Present Value of Costs	$11.36	$0.00
PAC - Benefit/Cost Ratio	3.4	#DIV/0!
PAC - Net Present Value	$27.22	$38.58
PAC - Levelized Cost	$0.0647/kWh	$0.0000/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM242

Inputs - Measure Considerations	
Measure Name:	Pilot 12W LED A19 Bulb
Incentive Amount:	$44.00
Measure/Project Cost:	$44.00
Gross Consumption Savings:	48 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	52 kWh/yr
Gross Demand Savings:	.017 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$6.97
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	111%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.04
PC - Net Present Value	$89.93
PC - Levelized Cost	$0.0825/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.80*
RIM - Net Present Value	*-$36.19*
RIM - Levelized Cost	*$0.3060/kWh*
TRC - Benefit/Cost Ratio	1.61
TRC - Net Present Value	$53.74
TRC - Levelized Cost	$0.1514/kWh
PAC - Benefit/Cost Ratio	*1.61*
PAC - Net Present Value	*$53.74*
PAC - Levelized Cost	*$0.1514/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$31.33*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.07*
RIM-YEC - Net Present Value	*$10.14*
RIM-YEC - Levelized Cost	*$0.2292/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$44.00
Incentive Amount in Year 1	$44.00
Assumed Program Administration Costs in Year 1	$44.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$89.93	$89.93
Discounted Cumulative Gross Energy Savings for 20 years	533 kWh	533 kWh
PC - Present Value of Benefits	$133.93	$133.93
PC - Present Value of Costs	$44.00	$44.00
PC - Benefit/Cost Ratio	3.04	3.04
PC - Net Present Value	$89.93	$89.93
PC - Levelized Cost	$0.0825/kWh	$0.0825/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$89.93	$89.93
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
RIM - Present Value of Benefits	$141.74	$141.74
RIM - Present Value of Costs	$177.93	$133.93
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$36.19	$7.81
RIM - Levelized Cost	$0 3060/kWh	$0.2304/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
TRC - Present Value of Benefits	$141.74	$141.74
TRC - Present Value of Costs	$88.00	$44.00
TRC - Benefit/Cost Ratio	1.61	3 2
TRC - Net Present Value	$53.74	$97.74
TRC - Levelized Cost	$0.1514/kWh	$0.0757/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$141.74	$141.74
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	581 kWh	581 kWh
PAC - Present Value of Benefits	$141.74	$141.74
PAC - Present Value of Costs	$88.00	$44.00
PAC - Benefit/Cost Ratio	1.6	3 2
PAC - Net Present Value	$53.74	$97.74
PAC - Levelized Cost	$0.1514/kWh	$0.0757/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM602

Inputs - Measure Considerations	
Measure Name:	Pilot 8W LED A19 Bulb
Incentive Amount:	$31.00
Measure/Project Cost:	$31.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$4.65
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	105%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.93
PC - Net Present Value	$59.95
PC - Levelized Cost	$0.0872/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.77*
RIM - Net Present Value	*-$27.46*
RIM - Levelized Cost	*$0.3146/kWh*
TRC - Benefit/Cost Ratio	1.52
TRC - Net Present Value	$32.49
TRC - Levelized Cost	$0.1600/kWh
PAC - Benefit/Cost Ratio	*1.52*
PAC - Net Present Value	*$32.49*
PAC - Levelized Cost	*$0.1600/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$20.89*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.03*
RIM-YEC - Net Present Value	*$3.43*
RIM-YEC - Levelized Cost	*$0.2372/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$31.00
Incentive Amount in Year 1	$31.00
Assumed Program Administration Costs in Year 1	$31.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$59.95	$59.95
Discounted Cumulative Gross Energy Savings for 20 years	355 kWh	355 kWh
PC - Present Value of Benefits	$90.95	$90.95
PC - Present Value of Costs	$31.00	$31.00
PC - Benefit/Cost Ratio	2.93	2.93
PC - Net Present Value	$59.95	$59.95
PC - Levelized Cost	$0.0872/kWh	$0.0872/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$59.95	$59.95
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
RIM - Present Value of Benefits	$94.49	$94.49
RIM - Present Value of Costs	$121.95	$90.95
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$27.46	$3.54
RIM - Levelized Cost	$0 3146/kWh	$0.2347/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
TRC - Present Value of Benefits	$94.49	$94.49
TRC - Present Value of Costs	$62.00	$31.00
TRC - Benefit/Cost Ratio	1.52	3.0
TRC - Net Present Value	$32.49	$63.49
TRC - Levelized Cost	$0.1600/kWh	$0.0800/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$94.49	$94.49
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	388 kWh	388 kWh
PAC - Present Value of Benefits	$94.49	$94.49
PAC - Present Value of Costs	$62.00	$31.00
PAC - Benefit/Cost Ratio	1.5	3.0
PAC - Net Present Value	$32.49	$63.49
PAC - Levelized Cost	$0.1600/kWh	$0.0800/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM612

Inputs - Measure Considerations	
Measure Name:	Pilot LED MR16 Bulbs
Incentive Amount:	$25.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	15 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	16 kWh/yr
Gross Demand Savings:	.005 kW
Gross Demand Savings w/ T&D losses:	0.01 kW
Participant's Savings on Year 1:	$2.18
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	61%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.12
PC - Net Present Value	$28.10
PC - Levelized Cost	$0.1501/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.57*
RIM - Net Present Value	*-$33.81*
RIM - Levelized Cost	*$0.4299/kWh*
TRC - Benefit/Cost Ratio	0.89
TRC - Net Present Value	-$5.71
TRC - Levelized Cost	$0.2752/kWh
PAC - Benefit/Cost Ratio	*0.89*
PAC - Net Present Value	*-$5.71*
PAC - Levelized Cost	*$0.2752/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.79*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.71*
RIM-YEC - Net Present Value	*-$19.33*
RIM-YEC - Levelized Cost	*$0.3440/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$25.00
Assumed Program Administration Costs in Year 1	$25.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$28.10	$28.10
Discounted Cumulative Gross Energy Savings for 20 years	167 kWh	167 kWh
PC - Present Value of Benefits	$53.10	$53.10
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.12	2.12
PC - Net Present Value	$28.10	$28.10
PC - Levelized Cost	$0.1501/kWh	$0.1501/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$28.10	$28.10
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
RIM - Present Value of Benefits	$44.29	$44.29
RIM - Present Value of Costs	$78.10	$53.10
RIM - Benefit/Cost Ratio	0.6	0.8
RIM - Net Present Value	-$33.81	-$8.81
RIM - Levelized Cost	$0.4299/kWh	$0.2923/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
TRC - Present Value of Benefits	$44.29	$44.29
TRC - Present Value of Costs	$50.00	$25.00
TRC - Benefit/Cost Ratio	0.89	1.8
TRC - Net Present Value	-$5.71	$19.29
TRC - Levelized Cost	$0 2752/kWh	$0.1376/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$44.29	$44.29
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	182 kWh	182 kWh
PAC - Present Value of Benefits	$44.29	$44.29
PAC - Present Value of Costs	$50.00	$25.00
PAC - Benefit/Cost Ratio	0.9	1.8
PAC - Net Present Value	-$5.71	$19.29
PAC - Levelized Cost	$0 2752/kWh	$0.1376/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM622

Inputs - Measure Considerations	
Measure Name:	Pilot LED PAR30 Bulbs
Incentive Amount:	$64.00
Measure/Project Cost:	$64.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	44 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	64%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.17
PC - Net Present Value	$74.94
PC - Levelized Cost	$0.1441/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.58*
RIM - Net Present Value	*-$84.83*
RIM - Levelized Cost	*$0.4189/kWh*
TRC - Benefit/Cost Ratio	0.92
TRC - Net Present Value	-$9.88
TRC - Levelized Cost	$0.2642/kWh
PAC - Benefit/Cost Ratio	*0.92*
PAC - Net Present Value	*-$9.88*
PAC - Levelized Cost	*$0.2642/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$26.11*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.74*
RIM-YEC - Net Present Value	*-$46.21*
RIM-YEC - Levelized Cost	*$0.3337/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$64.00
Incentive Amount in Year 1	$64.00
Assumed Program Administration Costs in Year 1	$64.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$74.94	$74.94
Discounted Cumulative Gross Energy Savings for 20 years	444 kWh	444 kWh
PC - Present Value of Benefits	$138.94	$138.94
PC - Present Value of Costs	$64.00	$64.00
PC - Benefit/Cost Ratio	2.17	2.17
PC - Net Present Value	$74.94	$74.94
PC - Levelized Cost	$0.1441/kWh	$0.1441/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$74.94	$74.94
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
RIM - Present Value of Benefits	$118.12	$118.12
RIM - Present Value of Costs	$202.94	$138.94
RIM - Benefit/Cost Ratio	0.6	0 9
RIM - Net Present Value	-$84.83	-$20.83
RIM - Levelized Cost	$0.4189/kWh	$0.2868/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
TRC - Present Value of Benefits	$118.12	$118.12
TRC - Present Value of Costs	$128.00	$64.00
TRC - Benefit/Cost Ratio	0.92	1.8
TRC - Net Present Value	-$9.88	$54.12
TRC - Levelized Cost	$0 2642/kWh	$0.1321/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$118.12	$118.12
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	484 kWh	484 kWh
PAC - Present Value of Benefits	$118.12	$118.12
PAC - Present Value of Costs	$128.00	$64.00
PAC - Benefit/Cost Ratio	0.9	1.8
PAC - Net Present Value	-$9.88	$54.12
PAC - Levelized Cost	$0 2642/kWh	$0.1321/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM632

Inputs - Measure Considerations	
Measure Name:	Pilot LED PAR38 Bulbs
Incentive Amount:	$53.00
Measure/Project Cost:	$53.00
Gross Consumption Savings:	55 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	60 kWh/yr
Gross Demand Savings:	.02 kW
Gross Demand Savings w/ T&D losses:	0.02 kW
Participant's Savings on Year 1:	$7.99
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	106%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.94
PC - Net Present Value	$103.05
PC - Levelized Cost	$0.0868/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.78*
RIM - Net Present Value	*-$46.63*
RIM - Levelized Cost	*$0.3138/kWh*
TRC - Benefit/Cost Ratio	1.53
TRC - Net Present Value	$56.41
TRC - Levelized Cost	$0.1591/kWh
PAC - Benefit/Cost Ratio	*1.53*
PAC - Net Present Value	*$56.41*
PAC - Levelized Cost	*$0.1591/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$35.90*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.04*
RIM-YEC - Net Present Value	*$6.46*
RIM-YEC - Levelized Cost	*$0.2364/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$53.00
Incentive Amount in Year 1	$53.00
Assumed Program Administration Costs in Year 1	$53.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$103.05	$103.05
Discounted Cumulative Gross Energy Savings for 20 years	611 kWh	611 kWh
PC - Present Value of Benefits	$156.05	$156.05
PC - Present Value of Costs	$53.00	$53.00
PC - Benefit/Cost Ratio	2.94	2.94
PC - Net Present Value	$103.05	$103.05
PC - Levelized Cost	$0.0868/kWh	$0.0868/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$103.05	$103.05
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
RIM - Present Value of Benefits	$162.41	$162.41
RIM - Present Value of Costs	$209.05	$156.05
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$46.63	$6.37
RIM - Levelized Cost	$0 3138/kWh	$0.2342/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
TRC - Present Value of Benefits	$162.41	$162.41
TRC - Present Value of Costs	$106.00	$53.00
TRC - Benefit/Cost Ratio	1.53	3.1
TRC - Net Present Value	$56.41	$109.41
TRC - Levelized Cost	$0.1591/kWh	$0.0796/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$162.41	$162.41
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	666 kWh	666 kWh
PAC - Present Value of Benefits	$162.41	$162.41
PAC - Present Value of Costs	$106.00	$53.00
PAC - Benefit/Cost Ratio	1.5	3.1
PAC - Net Present Value	$56.41	$109.41
PAC - Levelized Cost	$0.1591/kWh	$0.0796/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM442

Inputs - Measure Considerations	
Measure Name:	Pilot Spot or Task Lighting
Incentive Amount:	$25.00
Measure/Project Cost:	$25.00
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	43.62 kWh/yr
Gross Demand Savings:	.014 kW
Gross Demand Savings w/ T&D losses:	0.015562 kW
Participant's Savings on Year 1:	$5.81
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	81%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.87
PC - Net Present Value	$46.76
PC - Levelized Cost	$0.0841/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.76*
RIM - Net Present Value	*-$23.06*
RIM - Levelized Cost	*$0.2984/kWh*
TRC - Benefit/Cost Ratio	1.47
TRC - Net Present Value	$23.71
TRC - Levelized Cost	$0.1542/kWh
PAC - Benefit/Cost Ratio	*1.47*
PAC - Net Present Value	*$23.71*
PAC - Levelized Cost	*$0.1542/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$16.91*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$0.97*
RIM-YEC - Levelized Cost	*$0.2306/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$25.00
Incentive Amount in Year 1	$25.00
Assumed Program Administration Costs in Year 1	$25.00
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$46.76	$46.76
Discounted Cumulative Gross Energy Savings for 10 years	297 kWh	297 kWh
PC - Present Value of Benefits	$71.76	$71.76
PC - Present Value of Costs	$25.00	$25.00
PC - Benefit/Cost Ratio	2.87	2.87
PC - Net Present Value	$46.76	$46.76
PC - Levelized Cost	$0.0841/kWh	$0.0841/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$46.76	$46.76
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
RIM - Present Value of Benefits	$73.71	$73.71
RIM - Present Value of Costs	$96.76	$71.76
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$23.06	$1.94
RIM - Levelized Cost	$0 2984/kWh	$0.2213/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
TRC - Present Value of Benefits	$73.71	$73.71
TRC - Present Value of Costs	$50.00	$25.00
TRC - Benefit/Cost Ratio	1.47	2 9
TRC - Net Present Value	$23.71	$48.71
TRC - Levelized Cost	$0.1542/kWh	$0.0771/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$73.71	$73.71
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	324 kWh	324 kWh
PAC - Present Value of Benefits	$73.71	$73.71
PAC - Present Value of Costs	$50.00	$25.00
PAC - Benefit/Cost Ratio	1.5	2 9
PAC - Net Present Value	$23.71	$48.71
PAC - Levelized Cost	$0.1542/kWh	$0.0771/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM092

Inputs - Measure Considerations	
Measure Name:	Pilot Ultra Low-flow Showerheads
Incentive Amount:	$16.01
Measure/Project Cost:	$16.01
Gross Consumption Savings:	325 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	354 kWh/yr
Gross Demand Savings:	.116 kW
Gross Demand Savings w/ T&D losses:	.126 kW
Participant's Savings on Year 1:	$47.22
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	1033%
Suggested Program Cost (% of Incentive):	1033%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	24.73
PC - Net Present Value	$379.96
PC - Levelized Cost	$0.0066/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.07*
RIM - Net Present Value	*$37.49*
RIM - Levelized Cost	*$0.2131/kWh*
TRC - Benefit/Cost Ratio	3.30
TRC - Net Present Value	$417.46
TRC - Levelized Cost	$0.0689/kWh
PAC - Benefit/Cost Ratio	*3.30*
PAC - Net Present Value	*$417.46*
PAC - Levelized Cost	*$0.0689/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$137.43*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.53*
RIM-YEC - Net Present Value	*$216.99*
RIM-YEC - Levelized Cost	*$0.1486/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$16.01
Incentive Amount in Year 1	$16.01
Assumed Program Administration Costs in Year 1	$165.39
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$379.96	$379.96
Discounted Cumulative Gross Energy Savings for 10 years	2,416 kWh	2,416 kWh
PC - Present Value of Benefits	$395.97	$395.97
PC - Present Value of Costs	$16.01	$16.01
PC - Benefit/Cost Ratio	24.73	24.73
PC - Net Present Value	$379.96	$379.96
PC - Levelized Cost	$0.0066/kWh	$0.0066/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$379.96	$379.96
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
RIM - Present Value of Benefits	$598.86	$598.86
RIM - Present Value of Costs	$561.36	$395.97
RIM - Benefit/Cost Ratio	1.1	1 5
RIM - Net Present Value	$37.49	$202.89
RIM - Levelized Cost	$0 2131/kWh	$0.1503/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
TRC - Present Value of Benefits	$598.86	$598.86
TRC - Present Value of Costs	$181.40	$16.01
TRC - Benefit/Cost Ratio	3.30	37.4
TRC - Net Present Value	$417.46	$582.85
TRC - Levelized Cost	$0.0689/kWh	$0.0061/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$598.86	$598.86
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	2,634 kWh	2,634 kWh
PAC - Present Value of Benefits	$598.86	$598.86
PAC - Present Value of Costs	$181.40	$16.01
PAC - Benefit/Cost Ratio	3.3	37.4
PAC - Net Present Value	$417.46	$582.85
PAC - Levelized Cost	$0.0689/kWh	$0.0061/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM112

Inputs - Measure Considerations	
Measure Name:	Pilot Smart, Surge Protected Power Bars for PCs and TVs
Incentive Amount:	$50.00
Measure/Project Cost:	$50.00
Gross Consumption Savings:	68 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	74 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.85
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	69%
Suggested Program Cost (% of Incentive):	69%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.58
PC - Net Present Value	$79.24
PC - Levelized Cost	$0.0992/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.76*
RIM - Net Present Value	*-$38.84*
RIM - Levelized Cost	*$0.2980/kWh*
TRC - Benefit/Cost Ratio	1.48
TRC - Net Present Value	$40.40
TRC - Levelized Cost	$0.1538/kWh
PAC - Benefit/Cost Ratio	*1.48*
PAC - Net Present Value	*$40.40*
PAC - Levelized Cost	*$0.1538/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$28.66*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$1.41*
RIM-YEC - Levelized Cost	*$0.2302/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$50.00
Incentive Amount in Year 1	$50.00
Assumed Program Administration Costs in Year 1	$34.49
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$79.24	$79.24
Discounted Cumulative Gross Energy Savings for 10 years	504 kWh	504 kWh
PC - Present Value of Benefits	$129.24	$129.24
PC - Present Value of Costs	$50.00	$50.00
PC - Benefit/Cost Ratio	2.58	2.58
PC - Net Present Value	$79.24	$79.24
PC - Levelized Cost	$0.0992/kWh	$0.0992/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$79.24	$79.24
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
RIM - Present Value of Benefits	$124.89	$124.89
RIM - Present Value of Costs	$163.74	$129.24
RIM - Benefit/Cost Ratio	0.8	1.0
RIM - Net Present Value	-$38.84	-$4.35
RIM - Levelized Cost	$0 2980/kWh	$0.2352/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
TRC - Present Value of Benefits	$124.89	$124.89
TRC - Present Value of Costs	$84.49	$50.00
TRC - Benefit/Cost Ratio	1.48	2 5
TRC - Net Present Value	$40.40	$74.89
TRC - Levelized Cost	$0.1538/kWh	$0.0910/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$124.89	$124.89
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	549 kWh	549 kWh
PAC - Present Value of Benefits	$124.89	$124.89
PAC - Present Value of Costs	$84.49	$50.00
PAC - Benefit/Cost Ratio	1.5	2 5
PAC - Net Present Value	$40.40	$74.89
PAC - Levelized Cost	$0.1538/kWh	$0.0910/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM182

Inputs - Measure Considerations	
Measure Name:	Pilot DHW Tank Insulation
Incentive Amount:	$37.58
Measure/Project Cost:	$37.58
Gross Consumption Savings:	62 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	68 kWh/yr
Gross Demand Savings:	.022 kW
Gross Demand Savings w/ T&D losses:	.024 kW
Participant's Savings on Year 1:	$9.01
Measure Lifetime:	14 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	118%
Suggested Program Cost (% of Incentive):	118%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	3.47
PC - Net Present Value	$92.64
PC - Levelized Cost	$0.0658/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.84*
RIM - Net Present Value	*-$28.38*
RIM - Levelized Cost	*$0.2798/kWh*
TRC - Benefit/Cost Ratio	1.79
TRC - Net Present Value	$64.26
TRC - Levelized Cost	$0.1312/kWh
PAC - Benefit/Cost Ratio	*1.79*
PAC - Net Present Value	*$64.26*
PAC - Levelized Cost	*$0.1312/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$32.97*
RIM-YECL - Levelized Cost	*$0.1482/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.12*
RIM-YEC - Net Present Value	*$17.04*
RIM-YEC - Levelized Cost	*$0.2092/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.58
Incentive Amount in Year 1	$37.58
Assumed Program Administration Costs in Year 1	$44.17
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 14 years	$92.64	$92.64
Discounted Cumulative Gross Energy Savings for 14 years	571 kWh	571 kWh
PC - Present Value of Benefits	$130.22	$130.22
PC - Present Value of Costs	$37.58	$37.58
PC - Benefit/Cost Ratio	3.47	3.47
PC - Net Present Value	$92.64	$92.64
PC - Levelized Cost	$0.0658/kWh	$0.0658/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Present Value of Lost Revenues for 14 years	$92.64	$92.64
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
RIM - Present Value of Benefits	$146.01	$146.01
RIM - Present Value of Costs	$174.39	$130.22
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$28.38	$15.79
RIM - Levelized Cost	$0 2798/kWh	$0.2090/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
TRC - Present Value of Benefits	$146.01	$146.01
TRC - Present Value of Costs	$81.75	$37.58
TRC - Benefit/Cost Ratio	1.79	3 9
TRC - Net Present Value	$64.26	$108.43
TRC - Levelized Cost	$0.1312/kWh	$0.0603/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 14 years	$146.01	$146.01
Present Value of Avoided Capacity Costs for 14 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 14 years	623 kWh	623 kWh
PAC - Present Value of Benefits	$146.01	$146.01
PAC - Present Value of Costs	$81.75	$37.58
PAC - Benefit/Cost Ratio	1.8	3 9
PAC - Net Present Value	$64.26	$108.43
PAC - Levelized Cost	$0.1312/kWh	$0.0603/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM202

Inputs - Measure Considerations	
Measure Name:	Pilot DHW Pipe Insulation
Incentive Amount:	$0.79
Measure/Project Cost:	$0.79
Gross Consumption Savings:	34 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	37 kWh/yr
Gross Demand Savings:	.012 kW
Gross Demand Savings w/ T&D losses:	.013 kW
Participant's Savings on Year 1:	$4.94
Measure Lifetime:	15 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	3285%
Suggested Program Cost (% of Incentive):	3285%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	68.39
PC - Net Present Value	$53.23
PC - Levelized Cost	$0.0024/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$3.92*
RIM - Levelized Cost	*$0.2249/kWh*
TRC - Benefit/Cost Ratio	3.14
TRC - Net Present Value	$57.16
TRC - Levelized Cost	$0.0752/kWh
PAC - Benefit/Cost Ratio	*3.14*
PAC - Net Present Value	*$57.16*
PAC - Levelized Cost	*$0.0752/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$18.88*
RIM-YECL - Levelized Cost	*$0.1492/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.51*
RIM-YEC - Net Present Value	*$30.25*
RIM-YEC - Levelized Cost	*$0.1567/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$0.79
Incentive Amount in Year 1	$0.79
Assumed Program Administration Costs in Year 1	$25.95
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 15 years	$53.23	$53.23
Discounted Cumulative Gross Energy Savings for 15 years	326 kWh	326 kWh
PC - Present Value of Benefits	$54.02	$54.02
PC - Present Value of Costs	$0.79	$0.79
PC - Benefit/Cost Ratio	68.39	68.39
PC - Net Present Value	$53.23	$53.23
PC - Levelized Cost	$0.0024/kWh	$0.0024/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Present Value of Lost Revenues for 15 years	$53.23	$53.23
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
RIM - Present Value of Benefits	$83.90	$83.90
RIM - Present Value of Costs	$79.98	$54.02
RIM - Benefit/Cost Ratio	1.0	1.6
RIM - Net Present Value	$3.92	$29.88
RIM - Levelized Cost	$0 2249/kWh	$0.1519/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
TRC - Present Value of Benefits	$83.90	$83.90
TRC - Present Value of Costs	$26.74	$0.79
TRC - Benefit/Cost Ratio	3.14	106 2
TRC - Net Present Value	$57.16	$83.11
TRC - Levelized Cost	$0.0752/kWh	$0.0022/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 15 years	$83.90	$83.90
Present Value of Avoided Capacity Costs for 15 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 15 years	356 kWh	356 kWh
PAC - Present Value of Benefits	$83.90	$83.90
PAC - Present Value of Costs	$26.74	$0.79
PAC - Benefit/Cost Ratio	3.1	106 2
PAC - Net Present Value	$57.16	$83.11
PAC - Levelized Cost	$0.0752/kWh	$0.0022/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM482

Inputs - Measure Considerations	
Measure Name:	Pilot Motion Detectors - Indoor and Outdoor
Incentive Amount:	$22.94
Measure/Project Cost:	$22.94
Gross Consumption Savings:	66 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	72 kWh/yr
Gross Demand Savings:	.024 kW
Gross Demand Savings w/ T&D losses:	.026 kW
Participant's Savings on Year 1:	$9.59
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	146%
Suggested Program Cost (% of Incentive):	146%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.36
PC - Net Present Value	$77.15
PC - Levelized Cost	$0.0468/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.91*
RIM - Net Present Value	*-$12.07*
RIM - Levelized Cost	*$0.2499/kWh*
TRC - Benefit/Cost Ratio	2.15
TRC - Net Present Value	$65.08
TRC - Levelized Cost	$0.1057/kWh
PAC - Benefit/Cost Ratio	*2.15*
PAC - Net Present Value	*$65.08*
PAC - Levelized Cost	*$0.1057/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$27.90*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.24*
RIM-YEC - Net Present Value	*$24.37*
RIM-YEC - Levelized Cost	*$0.1840/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$22.94
Incentive Amount in Year 1	$22.94
Assumed Program Administration Costs in Year 1	$33.58
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$77.15	$77.15
Discounted Cumulative Gross Energy Savings for 10 years	490 kWh	490 kWh
PC - Present Value of Benefits	$100.09	$100.09
PC - Present Value of Costs	$22.94	$22.94
PC - Benefit/Cost Ratio	4.36	4.36
PC - Net Present Value	$77.15	$77.15
PC - Levelized Cost	$0.0468/kWh	$0.0468/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$77.15	$77.15
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
RIM - Present Value of Benefits	$121.60	$121.60
RIM - Present Value of Costs	$133.67	$100.09
RIM - Benefit/Cost Ratio	0.9	1 2
RIM - Net Present Value	-$12.07	$21.51
RIM - Levelized Cost	$0 2499/kWh	$0.1871/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
TRC - Present Value of Benefits	$121.60	$121.60
TRC - Present Value of Costs	$56.52	$22.94
TRC - Benefit/Cost Ratio	2.15	5 3
TRC - Net Present Value	$65.08	$98.66
TRC - Levelized Cost	$0.1057/kWh	$0.0429/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$121.60	$121.60
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	535 kWh	535 kWh
PAC - Present Value of Benefits	$121.60	$121.60
PAC - Present Value of Costs	$56.52	$22.94
PAC - Benefit/Cost Ratio	2.2	5 3
PAC - Net Present Value	$65.08	$98.66
PAC - Levelized Cost	$0.1057/kWh	$0.0429/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM152

Inputs - Measure Considerations	
Measure Name:	Pilot Auto Heater Timers
Incentive Amount:	$37.50
Measure/Project Cost:	$37.50
Gross Consumption Savings:	130 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	142 kWh/yr
Gross Demand Savings:	0.05 kW
Gross Demand Savings w/ T&D losses:	0.05 kW
Participant's Savings on Year 1:	$18.86
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	100%
Suggested Program Cost (% of Incentive):	176%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	5.05
PC - Net Present Value	$151.74
PC - Levelized Cost	$0.0389/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$12.42*
RIM - Levelized Cost	*$0.2155/kWh*
TRC - Benefit/Cost Ratio	3.19
TRC - Net Present Value	$164.16
TRC - Levelized Cost	$0.0713/kWh
PAC - Benefit/Cost Ratio	*3.19*
PAC - Net Present Value	*$164.16*
PAC - Levelized Cost	*$0.0713/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$54.89*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.51*
RIM-YEC - Net Present Value	*$84.11*
RIM-YEC - Levelized Cost	*$0.1510/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$37.50
Incentive Amount in Year 1	$37.50
Assumed Program Administration Costs in Year 1	$37.50
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$151.74	$151.74
Discounted Cumulative Gross Energy Savings for 10 years	965 kWh	965 kWh
PC - Present Value of Benefits	$189.24	$189.24
PC - Present Value of Costs	$37.50	$37.50
PC - Benefit/Cost Ratio	5.05	5.05
PC - Net Present Value	$151.74	$151.74
PC - Levelized Cost	$0.0389/kWh	$0.0389/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$151.74	$151.74
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
RIM - Present Value of Benefits	$239.16	$239.16
RIM - Present Value of Costs	$226.74	$189.24
RIM - Benefit/Cost Ratio	1.1	1 3
RIM - Net Present Value	$12.42	$49.92
RIM - Levelized Cost	$0 2155/kWh	$0.1799/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
TRC - Present Value of Benefits	$239.16	$239.16
TRC - Present Value of Costs	$75.00	$37.50
TRC - Benefit/Cost Ratio	3.19	6.4
TRC - Net Present Value	$164.16	$201.66
TRC - Levelized Cost	$0.0713/kWh	$0.0356/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$239.16	$239.16
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	1,052 kWh	1,052 kWh
PAC - Present Value of Benefits	$239.16	$239.16
PAC - Present Value of Costs	$75.00	$37.50
PAC - Benefit/Cost Ratio	3.2	6.4
PAC - Net Present Value	$164.16	$201.66
PAC - Levelized Cost	$0.0713/kWh	$0.0356/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM142

Inputs - Measure Considerations	
Measure Name:	Pilot Prog. Thermostats (Central)
Incentive Amount:	$62.50
Measure/Project Cost:	$62.50
Gross Consumption Savings:	827 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	902 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.322 kW
Participant's Savings on Year 1:	$120.16
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	741%
Suggested Program Cost (% of Incentive):	741%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	17.63
PC - Net Present Value	$1,039.26
PC - Levelized Cost	$0.0095/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*1.05*
RIM - Net Present Value	*$73.27*
RIM - Levelized Cost	*$0.2189/kWh*
TRC - Benefit/Cost Ratio	3.12
TRC - Net Present Value	$1,112.53
TRC - Levelized Cost	$0.0735/kWh
PAC - Benefit/Cost Ratio	*3.12*
PAC - Net Present Value	*$1,112.53*
PAC - Levelized Cost	*$0.0735/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$374.34*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.50*
RIM-YEC - Net Present Value	*$568.97*
RIM-YEC - Levelized Cost	*$0.1535/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$62.50
Incentive Amount in Year 1	$62.50
Assumed Program Administration Costs in Year 1	$462.95
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,039 26	$1,039.26
Discounted Cumulative Gross Energy Savings for 11 years	6,556 kWh	6,556 kWh
PC - Present Value of Benefits	$1,101.76	$1,101.76
PC - Present Value of Costs	$62.50	$62.50
PC - Benefit/Cost Ratio	17.63	17.63
PC - Net Present Value	$1,039.26	$1,039.26
PC - Levelized Cost	$0.0095/kWh	$0.0095/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,039.26	$1,039.26
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
RIM - Present Value of Benefits	$1,637.98	$1,637.98
RIM - Present Value of Costs	$1,564.70	$1,101.76
RIM - Benefit/Cost Ratio	1.0	1 5
RIM - Net Present Value	$73.27	$536.22
RIM - Levelized Cost	$0 2189/kWh	$0.1541/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
TRC - Present Value of Benefits	$1,637.98	$1,637.98
TRC - Present Value of Costs	$525.45	$62.50
TRC - Benefit/Cost Ratio	3.12	26 2
TRC - Net Present Value	$1,112.53	$1,575.48
TRC - Levelized Cost	$0.0735/kWh	$0.0087/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,637 98	$1,637.98
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,149 kWh	7,149 kWh
PAC - Present Value of Benefits	$1,637.98	$1,637.98
PAC - Present Value of Costs	$525.45	$62.50
PAC - Benefit/Cost Ratio	3.1	26 2
PAC - Net Present Value	$1,112.53	$1,575.48
PAC - Levelized Cost	$0.0735/kWh	$0.0087/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM212

Inputs - Measure Considerations	
Measure Name:	Pilot Prog. Thermostats
Incentive Amount:	$285.43
Measure/Project Cost:	$285.43
Gross Consumption Savings:	826 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	901 kWh/yr
Gross Demand Savings:	.295 kW
Gross Demand Savings w/ T&D losses:	.321 kW
Participant's Savings on Year 1:	$120.02
Measure Lifetime:	11 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	162%
Suggested Program Cost (% of Incentive):	162%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	4.64
PC - Net Present Value	$1,038.00
PC - Levelized Cost	$0.0436/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.92*
RIM - Net Present Value	*-$149.82*
RIM - Levelized Cost	*$0.2501/kWh*
TRC - Benefit/Cost Ratio	2.19
TRC - Net Present Value	$888.18
TRC - Levelized Cost	$0.1047/kWh
PAC - Benefit/Cost Ratio	*2.19*
PAC - Net Present Value	*$888.18*
PAC - Levelized Cost	*$0.1047/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$373.89*
RIM-YECL - Levelized Cost	*$0.1451/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.25*
RIM-YEC - Net Present Value	*$345.28*
RIM-YEC - Levelized Cost	*$0.1833/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$285.43
Incentive Amount in Year 1	$285.43
Assumed Program Administration Costs in Year 1	$462.39
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Gross Energy Savings for 11 years	6,548 kWh	6,548 kWh
PC - Present Value of Benefits	$1,323.43	$1,323.43
PC - Present Value of Costs	$285.43	$285.43
PC - Benefit/Cost Ratio	4.64	4.64
PC - Net Present Value	$1,038.00	$1,038.00
PC - Levelized Cost	$0.0436/kWh	$0.0436/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Present Value of Lost Revenues for 11 years	$1,038.00	$1,038.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
RIM - Present Value of Benefits	$1,636.00	$1,636.00
RIM - Present Value of Costs	$1,785.82	$1,323.43
RIM - Benefit/Cost Ratio	0.9	1 2
RIM - Net Present Value	-$149.82	$312.57
RIM - Levelized Cost	$0 2501/kWh	$0.1853/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
TRC - Present Value of Benefits	$1,636.00	$1,636.00
TRC - Present Value of Costs	$747.82	$285.43
TRC - Benefit/Cost Ratio	2.19	5.7
TRC - Net Present Value	$888.18	$1,350.57
TRC - Levelized Cost	$0.1047/kWh	$0.0400/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 11 years	$1,636.00	$1,636.00
Present Value of Avoided Capacity Costs for 11 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 11 years	7,141 kWh	7,141 kWh
PAC - Present Value of Benefits	$1,636.00	$1,636.00
PAC - Present Value of Costs	$747.82	$285.43
PAC - Benefit/Cost Ratio	2.2	5.7
PAC - Net Present Value	$888.18	$1,350.57
PAC - Levelized Cost	$0.1047/kWh	$0.0400/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM062

Inputs - Measure Considerations	
Measure Name:	Pilot E-Star TVs
Incentive Amount:	$1,125.00
Measure/Project Cost:	$1,125.00
Gross Consumption Savings:	69 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	75 kWh/yr
Gross Demand Savings:	.025 kW
Gross Demand Savings w/ T&D losses:	.027 kW
Participant's Savings on Year 1:	$10.03
Measure Lifetime:	10 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	3%
Suggested Program Cost (% of Incentive):	3%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.07
PC - Net Present Value	$80.67
PC - Levelized Cost	$2.1935/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.10*
RIM - Net Present Value	*-$1,113.64*
RIM - Levelized Cost	*$2.2185/kWh*
TRC - Benefit/Cost Ratio	0.11
TRC - Net Present Value	-$1,032.97
TRC - Levelized Cost	$2.0743/kWh
PAC - Benefit/Cost Ratio	*0.11*
PAC - Net Present Value	*-$1,032.97*
PAC - Levelized Cost	*$2.0743/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$29.18*
RIM-YECL - Levelized Cost	*$0.1440/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.11*
RIM-YEC - Net Present Value	*-$1,075.53*
RIM-YEC - Levelized Cost	*$2.0737/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$1,125.00
Incentive Amount in Year 1	$1,125.00
Assumed Program Administration Costs in Year 1	$35.11
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC)		
Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 10 years	$80.67	$80.67
Discounted Cumulative Gross Energy Savings for 10 years	513 kWh	513 kWh
PC - Present Value of Benefits	$1,205.67	$1,205.67
PC - Present Value of Costs	$1,125.00	$1,125.00
PC - Benefit/Cost Ratio	1.07	1.07
PC - Net Present Value	$80.67	$80.67
PC - Levelized Cost	$2.1935/kWh	$2.1935/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM)		
Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Present Value of Lost Revenues for 10 years	$80.67	$80.67
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
RIM - Present Value of Benefits	$127.14	$127.14
RIM - Present Value of Costs	$1,240.78	$1,205.67
RIM - Benefit/Cost Ratio	0.1	0.1
RIM - Net Present Value	-$1,113.64	-$1,078.53
RIM - Levelized Cost	$2 2185/kWh	$2.1557/kWh

Total Resource Cost Test (TRC)		
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
TRC - Present Value of Benefits	$127.14	$127.14
TRC - Present Value of Costs	$1,160.11	$1,125.00
TRC - Benefit/Cost Ratio	0.11	0.1
TRC - Net Present Value	-$1,032 97	-$997.86
TRC - Levelized Cost	$2.0743/kWh	$2.0115/kWh

Program Administrator Cost Test (PAC)		
Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 10 years	$127.14	$127.14
Present Value of Avoided Capacity Costs for 10 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 10 years	559 kWh	559 kWh
PAC - Present Value of Benefits	$127.14	$127.14
PAC - Present Value of Costs	$1,160.11	$1,125.00
PAC - Benefit/Cost Ratio	0.1	0.1
PAC - Net Present Value	-$1,032 97	-$997.86
PAC - Levelized Cost	$2.0743/kWh	$2.0115/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM082

Inputs - Measure Considerations	
Measure Name:	Pilot ESTAR Printers and Fax
Incentive Amount:	$200.00
Measure/Project Cost:	$200.00
Gross Consumption Savings:	32 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	35 kWh/yr
Gross Demand Savings:	.011 kW
Gross Demand Savings w/ T&D losses:	.012 kW
Participant's Savings on Year 1:	$4.61
Measure Lifetime:	6 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	5%
Suggested Program Cost (% of Incentive):	5%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.12
PC - Net Present Value	$24.48
PC - Levelized Cost	$1.2431/kWh
Simple Payback w/ Incentive (yr)	0.0 yr
RIM - Benefit/Cost Ratio	*0.16*
RIM - Net Present Value	*-$195.59*
RIM - Levelized Cost	*$1.3347/kWh*
TRC - Benefit/Cost Ratio	0.18
TRC - Net Present Value	-$171.11
TRC - Levelized Cost	$1.1952/kWh
PAC - Benefit/Cost Ratio	*0.18*
PAC - Net Present Value	*-$171.11*
PAC - Levelized Cost	*$1.1952/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$9.01*
RIM-YECL - Levelized Cost	*$0.1394/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.18*
RIM-YEC - Net Present Value	*-$184.49*
RIM-YEC - Levelized Cost	*$1.2468/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$200.00
Incentive Amount in Year 1	$200.00
Assumed Program Administration Costs in Year 1	$9.69
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 6 years	$24.48	$24.48
Discounted Cumulative Gross Energy Savings for 6 years	161 kWh	161 kWh
PC - Present Value of Benefits	$224.48	$224.48
PC - Present Value of Costs	$200.00	$200.00
PC - Benefit/Cost Ratio	1.12	1.12
PC - Net Present Value	$24.48	$24.48
PC - Levelized Cost	$1 2431/kWh	$1.2431/kWh
Simple Payback with Incentive	0.0 yr	0.0 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Present Value of Lost Revenues for 6 years	$24.48	$24.48
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
RIM - Present Value of Benefits	$38.58	$38.58
RIM - Present Value of Costs	$234.17	$224.48
RIM - Benefit/Cost Ratio	0.2	0 2
RIM - Net Present Value	-$195 59	-$185.90
RIM - Levelized Cost	$1 3347/kWh	$1.2795/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
TRC - Present Value of Benefits	$38.58	$38.58
TRC - Present Value of Costs	$209.69	$200.00
TRC - Benefit/Cost Ratio	0.18	0 2
TRC - Net Present Value	-$171.11	-$161.42
TRC - Levelized Cost	$1.1952/kWh	$1.1399/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 6 years	$38.58	$38.58
Present Value of Avoided Capacity Costs for 6 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 6 years	175 kWh	175 kWh
PAC - Present Value of Benefits	$38.58	$38.58
PAC - Present Value of Costs	$209.69	$200.00
PAC - Benefit/Cost Ratio	0.2	0 2
PAC - Net Present Value	-$171.11	-$161.42
PAC - Levelized Cost	$1.1952/kWh	$1.1399/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM032

Inputs - Measure Considerations	
Measure Name:	Pilot Cold Temp Heat Pumps
Incentive Amount:	$5,000.00
Measure/Project Cost:	$8,498.44
Gross Consumption Savings:	6,780 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7,394 kWh/yr
Gross Demand Savings:	2.42 kW
Gross Demand Savings w/ T&D losses:	2.64 kW
Participant's Savings on Year 1:	$985.13
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	138%
Suggested Program Cost (% of Incentive):	138%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	2.08
PC - Net Present Value	$9,204.38
PC - Levelized Cost	$0.1129/kWh
Simple Payback w/ Incentive (yr)	3.6 yr
RIM - Benefit/Cost Ratio	*0.81*
RIM - Net Present Value	*-$4,582.55*
RIM - Levelized Cost	*$0.2996/kWh*
TRC - Benefit/Cost Ratio	1.30
TRC - Net Present Value	$4,621.84
TRC - Levelized Cost	$0.1875/kWh
PAC - Benefit/Cost Ratio	*1.68*
PAC - Net Present Value	*$8,120.28*
PAC - Levelized Cost	*$0.1449/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$4,425.66*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.10*
RIM-YEC - Net Present Value	*$1,961.99*
RIM-YEC - Levelized Cost	*$0.2232/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8,498.44
Incentive Amount in Year 1	$5,000.00
Assumed Program Administration Costs in Year 1	$6,900.67
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Gross Energy Savings for 20 years	75,306 kWh	75,306 kWh
PC - Present Value of Benefits	$17,702.82	$17,702.82
PC - Present Value of Costs	$8,498.44	$8,498.44
PC - Benefit/Cost Ratio	2.08	2.08
PC - Net Present Value	$9,204.38	$9,204.38
PC - Levelized Cost	$0.1129/kWh	$0.1129/kWh
Simple Payback with Incentive	3.6 yr	3.6 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
RIM - Present Value of Benefits	$20,020.95	$20,020.95
RIM - Present Value of Costs	$24,603.49	$17,702.82
RIM - Benefit/Cost Ratio	0.8	1.1
RIM - Net Present Value	-$4,582.55	$2,318.12
RIM - Levelized Cost	$0 2996/kWh	$0.2156/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
TRC - Present Value of Benefits	$20,020 95	$20,020.95
TRC - Present Value of Costs	$15,399.11	$8,498.44
TRC - Benefit/Cost Ratio	1.30	2.4
TRC - Net Present Value	$4,621.84	$11,522.51
TRC - Levelized Cost	$0.1875/kWh	$0.1035/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
PAC - Present Value of Benefits	$20,020 95	$20,020.95
PAC - Present Value of Costs	$11,900.67	$5,000.00
PAC - Benefit/Cost Ratio	1.7	4.0
PAC - Net Present Value	$8,120.28	$15,020.95
PAC - Levelized Cost	$0.1449/kWh	$0.0609/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM372

Inputs - Measure Considerations	
Measure Name:	Pilot Ground Heat Pumps - Closed
Incentive Amount:	$9,000.00
Measure/Project Cost:	$34,245.24
Gross Consumption Savings:	8,605 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	9,384 kWh/yr
Gross Demand Savings:	3.07 kW
Gross Demand Savings w/ T&D losses:	3.35 kW
Participant's Savings on Year 1:	$1,250.31
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	97%
Suggested Program Cost (% of Incentive):	97%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.73
PC - Net Present Value	-$9,123.14
PC - Levelized Cost	$0.3583/kWh
Simple Payback w/ Incentive (yr)	20.2 yr
RIM - Benefit/Cost Ratio	*0.75*
RIM - Net Present Value	*-$8,470.18*
RIM - Levelized Cost	*$0.3251/kWh*
TRC - Benefit/Cost Ratio	0.59
TRC - Net Present Value	-$17,593.32
TRC - Levelized Cost	$0.4126/kWh
PAC - Benefit/Cost Ratio	*1.43*
PAC - Net Present Value	*$7,651.91*
PAC - Levelized Cost	*$0.1704/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$5,616.94*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*0.99*
RIM-YEC - Net Present Value	*-$164.02*
RIM-YEC - Levelized Cost	*$0.2468/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$34,245 24
Incentive Amount in Year 1	$9,000.00
Assumed Program Administration Costs in Year 1	$8,758.15
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Gross Energy Savings for 20 years	95,576 kWh	95,576 kWh
PC - Present Value of Benefits	$25,122.09	$25,122.09
PC - Present Value of Costs	$34,245 24	$34,245.24
PC - Benefit/Cost Ratio	0.73	0.73
PC - Net Present Value	-$9,123.14	-$9,123.14
PC - Levelized Cost	$0 3583/kWh	$0.3583/kWh
Simple Payback with Incentive	20 2 yr	20.2 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
RIM - Present Value of Benefits	$25,410.06	$25,410.06
RIM - Present Value of Costs	$33,880.24	$25,122.09
RIM - Benefit/Cost Ratio	0.7	1.0
RIM - Net Present Value	-$8,470.18	$287.97
RIM - Levelized Cost	$0 3251/kWh	$0.2410/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
TRC - Present Value of Benefits	$25,410.06	$25,410.06
TRC - Present Value of Costs	$43,003 39	$34,245.24
TRC - Benefit/Cost Ratio	0.59	0.7
TRC - Net Present Value	-$17,593 32	-$8,835.17
TRC - Levelized Cost	$0.4126/kWh	$0.3286/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
PAC - Present Value of Benefits	$25,410.06	$25,410.06
PAC - Present Value of Costs	$17,758.15	$9,000.00
PAC - Benefit/Cost Ratio	1.4	2.8
PAC - Net Present Value	$7,651.91	$16,410.06
PAC - Levelized Cost	$0.1704/kWh	$0.0863/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM03

Inputs - Measure Considerations	
Measure Name:	Cold Temp Heat Pumps
Incentive Amount:	$2,500.00
Measure/Project Cost:	$8,498.44
Gross Consumption Savings:	6,780 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	7,394 kWh/yr
Gross Demand Savings:	2.42 kW
Gross Demand Savings w/ T&D losses:	2.64 kW
Participant's Savings on Year 1:	$985.13
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	216%
Suggested Program Cost (% of Incentive):	216%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	1.79
PC - Net Present Value	$6,704.38
PC - Levelized Cost	$0.1129/kWh
Simple Payback w/ Incentive (yr)	6.1 yr
RIM - Benefit/Cost Ratio	*0.97*
RIM - Net Present Value	*-$577.12*
RIM - Levelized Cost	*$0.2508/kWh*
TRC - Benefit/Cost Ratio	1.44
TRC - Net Present Value	$6,127.27
TRC - Levelized Cost	$0.1692/kWh
PAC - Benefit/Cost Ratio	*2.54*
PAC - Net Present Value	*$12,125.71*
PAC - Levelized Cost	*$0.0961/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$4,425.66*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.38*
RIM-YEC - Net Present Value	*$5,967.42*
RIM-YEC - Levelized Cost	*$0.1780/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$8,498.44
Incentive Amount in Year 1	$2,500.00
Assumed Program Administration Costs in Year 1	$5,395 24
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Gross Energy Savings for 20 years	75,306 kWh	75,306 kWh
PC - Present Value of Benefits	$15,202.82	$15,202.82
PC - Present Value of Costs	$8,498.44	$8,498.44
PC - Benefit/Cost Ratio	1.79	1.79
PC - Net Present Value	$6,704.38	$6,704.38
PC - Levelized Cost	$0.1129/kWh	$0.1129/kWh
Simple Payback with Incentive	6.1 yr	6.1 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$12,702.82	$12,702.82
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
RIM - Present Value of Benefits	$20,020.95	$20,020.95
RIM - Present Value of Costs	$20,598.06	$15,202.82
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	-$577.12	$4,818.12
RIM - Levelized Cost	$0 2508/kWh	$0.1851/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
TRC - Present Value of Benefits	$20,020 95	$20,020.95
TRC - Present Value of Costs	$13,893.68	$8,498.44
TRC - Benefit/Cost Ratio	1.44	2.4
TRC - Net Present Value	$6,127.27	$11,522.51
TRC - Levelized Cost	$0.1692/kWh	$0.1035/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$20,020 95	$20,020.95
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	82,122 kWh	82,122 kWh
PAC - Present Value of Benefits	$20,020 95	$20,020.95
PAC - Present Value of Costs	$7,895.24	$2,500.00
PAC - Benefit/Cost Ratio	2.5	8.0
PAC - Net Present Value	$12,125.71	$17,520.95
PAC - Levelized Cost	$0.0961/kWh	$0.0304/kWh

Energy Conservation Measure - Justification of the Incentive Level

ECM37

Inputs - Measure Considerations	
Measure Name:	Ground Heat Pumps - Closed
Incentive Amount:	$3,500.00
Measure/Project Cost:	$34,245.24
Gross Consumption Savings:	8,605 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	9,384 kWh/yr
Gross Demand Savings:	3.07 kW
Gross Demand Savings w/ T&D losses:	3.35 kW
Participant's Savings on Year 1:	$1,250.31
Measure Lifetime:	20 yr

Inputs - Program Considerations	
Program Cost (% of Incentive):	196%
Suggested Program Cost (% of Incentive):	196%
Forecasted Freeridership:	0%
Forecasted Participant Spillover:	0%
Forecasted Non-participant Spillover:	0%
Forecasted Rebound Effects:	0%

Outputs with Program Costs	
PC - Benefit/Cost Ratio	0.57
PC - Net Present Value	-$14,623.14
PC - Levelized Cost	$0.3583/kWh
Simple Payback w/ Incentive (yr)	24.6 yr
RIM - Benefit/Cost Ratio	*0.96*
RIM - Net Present Value	*-$1,059.53*
RIM - Levelized Cost	*$0.2540/kWh*
TRC - Benefit/Cost Ratio	0.62
TRC - Net Present Value	-$15,682.67
TRC - Levelized Cost	$0.3943/kWh
PAC - Benefit/Cost Ratio	*2.46*
PAC - Net Present Value	*$15,062.57*
PAC - Levelized Cost	*$0.0993/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.62*
RIM-YECL - Net Present Value	*-$5,616.94*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.36*
RIM-YEC - Net Present Value	*$7,246.63*
RIM-YEC - Levelized Cost	*$0.1809/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	$34,245 24
Incentive Amount in Year 1	$3,500.00
Assumed Program Administration Costs in Year 1	$6,847 50
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership P. Spi lover

N.-p. Spillover - Rebound

Participant Cost Test (PC) *Cumulative Present Value of Cashflows w/ PC Discount Rates*	*With Program Costs*	*W/o Program Costs*
Present Value of Participant's Avoided Energy Cost for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Gross Energy Savings for 20 years	95,576 kWh	95,576 kWh
PC - Present Value of Benefits	$19,622.09	$19,622.09
PC - Present Value of Costs	$34,245 24	$34,245.24
PC - Benefit/Cost Ratio	0.57	0.57
PC - Net Present Value	-$14,623.14	-$14,623.14
PC - Levelized Cost	$0 3583/kWh	$0.3583/kWh
Simple Payback with Incentive	24.6 yr	24.6 yr

Ratepayer Impact Measure Test (RIM) *Cumulative Present Value of Cashflows w/ RIM Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Present Value of Lost Revenues for 20 years	$16,122.09	$16,122.09
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
RIM - Present Value of Benefits	$25,410.06	$25,410.06
RIM - Present Value of Costs	$26,469.59	$19,622.09
RIM - Benefit/Cost Ratio	1.0	1 3
RIM - Net Present Value	-$1,059.53	$5,787.97
RIM - Levelized Cost	$0 2540/kWh	$0.1883/kWh

Total Resource Cost Test (TRC) *Cumulative Present Value of Cashflows w/ TRC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
TRC - Present Value of Benefits	$25,410.06	$25,410.06
TRC - Present Value of Costs	$41,092.74	$34,245.24
TRC - Benefit/Cost Ratio	0.62	0.7
TRC - Net Present Value	-$15,682.67	-$8,835.17
TRC - Levelized Cost	$0 3943/kWh	$0.3286/kWh

Program Administrator Cost Test (PAC) *Cumulative Present Value of Cashflows w/ PAC Discount Rate*	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$25,410.06	$25,410.06
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	104,227 kWh	104,227 kWh
PAC - Present Value of Benefits	$25,410.06	$25,410.06
PAC - Present Value of Costs	$10,347 50	$3,500.00
PAC - Benefit/Cost Ratio	2.5	7 3
PAC - Net Present Value	$15,062.57	$21,910.06
PAC - Levelized Cost	$0.0993/kWh	$0.0336/kWh

YUB-YECL-28

Reference: General, Yukon Five Year Demand Side Management Plan

The Board wants to better understand some of the programs in the DSM plan

Request:

(a) Why do YEC and YECL have a scenario where government buildings are excluded?

(b) Please describe whether non-incentive costs for these programs are fixed costs (i.e. if no participants, then will the costs be the same?).

(c) Please describe whether the incentive costs for these programs are purely variable costs (i.e., if no participants, then will the costs will be zero?).

(d) For the programs involving rebates or some sort of cash incentive, what will happen to total costs if the participation rate is much higher than YEC and YECL anticipated? Do YEC and YECL have a cap on how much can be spent on these programs or how many participants will be accepted each year?

(e) What if the participation rate of these programs is much lower than YEC and YECL anticipated?

(f) For programs that involve providing the participant with a rebate or some sort of cash incentive, why do YEC and YECL have to provide such a rebate or incentive if the programs pass the "Participant Costs" test. If they are rational profit maximizing agents, will the participants/owners/managers not be willing to take on these activities independent of any incentive from YEC and YECL?

Response:

(a) During consultation, stakeholders provided input as to whether government accounts should be included or excluded from the DSM programs. The utilities analyzed both scenarios and determined there is a marginal increase in costs to deliver programs to government accounts. However, by providing programs to government accounts, a substantial electricity savings could be achieved. It

should be noted that government accounts include municipal, community, territorial, federal and First Nation governments. The utilities felt that due to the divide in stakeholder opinions, the decision as to whether government accounts should or should not be included in programs was best determined by the YUB.

Based on the marginal cost increase versus the substantial electricity savings, it is the utilities' opinion that government accounts should be allowed to participate in the DSM program. Each individual government account holder can choose how they then participate. The utilities request that the YUB select one scenario for implementation, with or without government accounts.

(b) Generally speaking, non-incentive costs related to the launch of the programs are fixed. Promotional or educational costs are notionally fixed, although they can be slowly ramped up or down to maximize cost-effectiveness. After the launch stage a large portion of non-incentive direct costs are marginal, i.e. if no participants, these costs will go down for the period as a result.

In addition, DSM staff costs are fixed as the utilities will not instantly hire and fire DSM staff in reaction to demand. However, based on early uptake numbers and market feedback, the utilities will be able to make medium- to long-term adjustments to the DSM staff to match a less- or more-than-expected number of transactions, ramping up or down the cost accordingly to maximize cost-effectiveness.

(c) Incentive costs are variable with the number of participants in that particular program, i.e. should there be zero participants, zero dollars will be spent on incentives.

(d) In the Program Portfolio *(*Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application*),* an estimated number of participants is forecast for each program. The estimate of participants was factored into the costs of each program. It is anticipated that during the implementation of the programs, the utilities would not exceed these participant numbers. However, the utilities require the ability to be flexible with programs. The utilities reserve the right to adjust the data inputs as necessary in accordance with market conditions. While program budgets are flexible, annual budgets will be respected. This process of program evaluation is outlined in the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1*.*

(e) The utilities have developed an Evaluation, Measurement and Verification Plan to allow for the flexibility to adjust programs as results are achieved. Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for more details.

(f) It should be noted that the Participant Cost Test is used to assess the cost effectiveness from the perspective of the participant after the application of the incentive, not before. Hurdles, barriers and program rationales are laid out in detail in the Evaluation, Measurement and Verification plans. Please refer to the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1, for more details.

The question in 28(f) would be correct if markets and consumers were behaving in a perfectly rational manner from a financial standpoint, and if energy-efficiency innovations were adopted instantaneously as soon as they became economically viable. On both counts, this is not the case. Market failures, barriers and hurdles slow down the adoption of emerging cost-effective technologies and practices. Moreover, accelerating the penetration of cost-effective technologies and practices as compared to normal market adoption generates wealth for all ratepayers as illustrated by the positive TRC test by avoiding primary energy costs, and differing investments in generation, transmission and/or distribution capacity.

Many consumers do not purchase or invest in the most energy efficient option on their own because, for example:

- of the incremental initial cost of the conservation measure;
- the products don't have as much in-store visibility as base-case products;
- the sales people do not push these products as much because they are not familiar with them;
- consumers aren't provided with the information in a timely manner to make a choice;
- consumers don't invest the time to look into the new options;

- consumers don't trust the information that is being provided to them by the vendors; or

- consumers make decisions based on habits rather than a careful comparison between options.

Rebates/incentives are effective at generating incremental savings because, for example:

- Notionally, rebates/incentives get results by offsetting the initial cost hurdle, and/or lowering the simple payback or knocking down the risk of "trying" the technology;

- Even without an actual significant initial cost hurdle, rebates have an influence on purchase habits – to illustrate the point, rebates are tactics that are used frequently by marketers to influence consumers, get them to know new products and change their habits;

- In other jurisdictions, consumers like to rely on incentive programs to identify the most energy efficient option(s). Many consumers will trust the utility more than they would trust the vendors, and tend to integrate program eligibility criteria in their purchase/investment decision criteria; and

- Incentive programs increase the visibility and effectiveness of energy performance labeling program (informational program) like the Energy Star.

YUB-YECL-29

Reference: Residential Programs, Yukon Five Year Demand Side Management Plan

The Board wants to better understand the Residential programs proposed in the Five Year Demand Side Management Plan.

Request:

(a) With regard to the LED Lighting and Automotive Heater Timer Rebates, how much of the total costs of purchase will the rebates cover?

(b) With regard to the Low-cost Energy Efficient Products, please provide more details regarding what costs are included in the non-incentive and incentive costs? Please confirm whether or not rebates will be a part of this program. If confirmed, how much will rebates account for the total costs of these products?

(c) With regard to the Low-cost Energy Efficient Products, please confirm that YEC and YECL plan on promoting certain energy-efficient products in stores. Please describe whether YEC and YECL have started this initiative, and if so, identify in which stores.

(d) With regard to the CCHP and GSHP Initiative, please describe how much money YEC and YECL plan on giving to purchasers of a new home with a CCHP or GSHP system, or to owners of homes with electric central air heating systems to retrofit their home with CCHP or GSHP. For how much of the total costs will this incentive account?

(e) The Public Engagement, Education and Communication program appears to have a number of overlapping areas and activities with that of the Low-cost Energy Efficient Products program. Please confirm and explain the reasons for the overlaps.

(f) On page 20 of the Yukon Five Year Demand Side Management Plan, YEC and YECL noted that “many of the engagement initiatives carried out by the Utilities will also be used to disseminate information about the Yukon Housing conservation programs and the ESC energy conservation programs to increase value for the audience and create synergy between stakeholders.” Please

describe whether YEC and YECL will recover any of the costs attributable to these activities from these stakeholders. If not, how much money can be attributable to these activities?

Response:

(a) The incentive levels for this program are in the table below (taken from pages 72 and 76 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 67: Prescriptive List of Residential LED Lighting and Block-Heater Timer Energy Conservation Measures

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM151	Block Heater Timer	130 kWh/unit	0.046 kW/unit	100%	$37.50/unit	10.0 yr	$20.00/unit
ECM24	12W LED A19 Bulb	48 kWh/unit	0.017 kW/unit	110%	$44.00/unit	20.0 yr	$18.00/unit
ECM60	8W LED A19 Bulb	32.0 kWh/unit	0.011 kW/unit	110%	$30.00/unit	20.0 yr	$12.00/unit
ECM61	LED MR16 Bulbs	15.0 kWh/unit	0.005 kW/unit	110%	$20.00/unit	20.0 yr	$10.00/unit
ECM62	LED PAR30 Bulbs	40.0 kWh/unit	0.014 kW/unit	110%	$51.00/unit	20.0 yr	$20.00/unit
ECM63	LED PAR38 Bulbs	55.0 kWh/unit	0.020 kW/unit	110%	$43.00/unit	20.0 yr	$20.00/unit
ECM44	Spot or Task Lighting	40.0 kWh/unit	0.014 kW/unit	80%	$25.00/unit	10.0 yr	$10.00/unit

Exhibit 1: Participation Projections – LED Lighting and Block-Heater Timer Rebates

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM151	Block Heater Timer	0 units	68 units	109 units	109 units	109 units	395 units
ECM24	12W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM60	8W LED A19 Bulb	349 units	1,455 units	1,455 units	1,455 units	1,455 units	6,167 units
ECM61	LED MR16 Bulbs	55 units	259 units	259 units	259 units	259 units	1,089 units
ECM62	LED PAR30 Bulbs	14 units	79 units	79 units	79 units	79 units	328 units
ECM63	LED PAR38 Bulbs	10 units	59 units	59 units	59 units	59 units	246 units
ECM44	Spot or Task Lighting	9 units	41 units	41 units	41 units	41 units	172 units

(b) The plan is to have low-cost products being given away for free. This is one of the tactics for this program element. Rebate costs represent the full cost of the products (not the incremental cost).

Other tactics include educational materials, in-store events, sales people training, point-of-purchase materials. Therefore, the non-incentive costs include:

- Initial Set-up and Preparation of the distribution (Time);
- Procurement and Inventory Management (Time);
- Scorecard Crunching, Analysis & Reporting (Time);

- Expense Budget: Shipping (Mostly direct cost, perhaps some time);
- Point-of-Purchase Materials, and educational brochures - Early Support & Training, Research and Creation, In-store Events, Supervision (time); and
- Expense Budget Related with Materials (mostly direct costs).

This information is also provided in the detailed budget. Please refer to the *DSM Program Detailed Budgets*, provided as YUB-YECL-29(b) Attachment 1, for details.

(c) Yukon Energy and Yukon Electrical are planning on working with local retailers to implement this program; however, this program initiative has not started. Upon launch of the DSM programs, in-store promotion is identified as one of the communication strategies.

(d) As the CCHP and the GSHP programs are pilot programs, please refer to the incentive level chart and participant level projections as listed below (taken from pages 90 and 94 of the Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 81: Inputs and Assumptions of Residential New-Construction CCHP and GSHP Initiative

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM032	Pilot Cold Temp Heat Pumps	6,780 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$5,000.00/unit
ECM372	Pilot Ground Heat Pumps - Closed	8,605 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$9,000.00/unit
ECM03	Cold Temp Heat Pumps	6,780.0 kWh/unit	2.421 kW/unit	100%	$8,498.44/unit	20.0 yr	$2,500.00/unit
ECM37	Ground Heat Pumps - Closed	8,605.0 kWh/unit	3.070 kW/unit	100%	$34,245.24/unit	20.0 yr	$3,500.00/unit

Exhibit 84: Participation Projections – CCHP and GSHP Initiatives

ID	Measure Short Name	Year 1	Year 2	Year 3	Year 4	Year 5	Total
ECM032	Pilot Cold Temp Heat Pumps	1 units	0 units	0 units	1 units	0 units	2 units
ECM372	Pilot Ground Heat Pumps - Closed	0 units	1 units	1 units	0 units	0 units	2 units
ECM03	Cold Temp Heat Pumps	0 units	0 units	0 units	6 units	6 units	12 units
ECM37	Ground Heat Pumps - Closed	0 units	0 units	0 units	1 units	1 units	2 units

(e) It is standard practice to have elements of a DSM portfolio to complement each other and for their respective theory to be overlapping; together the program elements make a more effective portfolio. The division of the actual activities between one element or another, in this case, is arbitrary and is mostly based on the premise that the utilities are claiming a direct impact for the Low-cost Energy Efficient Products element and not for the Public Engagement, Education and Communication. However, the costs are not overlapping and there is no cost double-counting.

- Low-cost Energy Efficient Products element: was intended to induce change in purchase habits in retail stores therefore generating a direct impact which will be measureable through the monitoring of sales data. Please find details in the *DSM Program Evaluation Measurement and Verification Plan*, provided in YUB-YECL-26(a) Attachment 1.

- Public Engagement, Education and Communication is a set of enabling tactics designed to boost uptake of all program elements (including the Low-Cost EE Products Elements) and to create a culture of energy efficiency. The utilities do not intend to claim a direct impact for this.

(f) Yukon Electrical and Yukon Energy have a cooperative relationship with Energy Solutions Centre (ESC) and Yukon Housing and will, through DSM public communication, assist in distributing additional energy efficiency materials that

are produced by these agencies. As these public communication activities are already part of the utility DSM programs there are no incremental costs associated with the distribution of additional ESC and Yukon Housing information. The benefit is purely an added convenience to the residential and commercial customer. Additionally as the utilities are mindful of the programming presented by ESC and Yukon Housing, there is an added benefit of uptake of the ESC and Yukon Housing programs.

Appendix C Detailed Budgets

ICF Marbek

Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Lighting Redesign and Equipment Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings - ECM91	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions per Building	$ 315	$ 2,798	$ 5,639	$ 6,195	$ 4,786	$ 19,733
In-depth Blueprint & Layout Verification (1/3 verification)	$ 105	$ 933	$ 1,880	$ 2,065	$ 1,595	$ 6,578
Incentive Amount - Redesign Incentive - ECM91	$ 3,672	$ 20,350	$ 33,356	$ 33,356	$ 16,678	$ 107,412
Initial Set-up and Preparation	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 4,225	$ 10,964	$ 12,906	$ 13,294	$ 41,389
In-Depth Verification & Site Visit (1/3)	$ -	$ 1,408	$ 3,655	$ 4,302	$ 4,431	$ 13,796
Expense Budget Site Visits (1/3)	$ -	$ 282	$ 731	$ 860	$ 886	$ 2,759
Incentive for Typical Lighting Project in Existing Bldg - Office - ECM80	$ -	$ 1,873	$ 5,073	$ 5,797	$ 5,797	$ 18,541
Incentive for Typical Lighting Project in Existing Bldg - Food Retail - ECM81	$ -	$ 1,048	$ 2,768	$ 3,163	$ 3,163	$ 10,141
Incentive for Typical Lighting Project in Existing Bldg - Non Food Retail - ECM82	$ -	$ 4,402	$ 11,562	$ 13,213	$ 13,213	$ 42,390
Incentive for Typical Lighting Project in Existing Bldg - Hotel/Motel - ECM83	$ -	$ 2,120	$ 4,946	$ 5,652	$ 5,652	$ 18,370
Incentive for Typical Lighting Project in Existing Bldg - Restaurant - ECM86	$ -	$ 2,117	$ 4,939	$ 5,645	$ 5,645	$ 18,347
Incentive for Typical Lighting Project in Existing Bldg - Recreation - ECM87	$ -	$ -	$ -	$ -	$ -	$ -
Incentive for Typical Lighting Project in Existing Bldg - Warehouse - ECM88	$ -	$ 1,693	$ 3,950	$ 4,514	$ 4,514	$ 14,671
Incentive for 12W LED A19 Bulb Installed as Part of Projects - ECM92	$ -	$ 9,989	$ 23,309	$ 26,638	$ 26,638	$ 86,575
Incentive for 8W LED A19 Bulb Installed as Part of Projects - ECM93	$ -	$ 14,207	$ 33,150	$ 37,886	$ 37,886	$ 123,129
Incentive for LED MR16 Bulbs Installed as Part of Projects - ECM94	$ -	$ 9,249	$ 21,582	$ 24,665	$ 24,665	$ 80,162
Incentive for LED PAR30 Bulbs Installed as Part of Projects - ECM95	$ -	$ 14,799	$ 34,531	$ 39,464	$ 39,464	$ 128,259
Incentive for LED PAR38 Bulbs Installed as Part of Projects - ECM96	$ -	$ 10,763	$ 25,114	$ 28,701	$ 28,701	$ 93,280
Incentive for Spot or task lighting Installed as Part of Projects - ECM97	$ -	$ 3,700	$ 8,633	$ 9,866	$ 9,866	$ 32,065
Subtotal	$ 49,975	$ 105,956	$ 235,780	$ 264,892	$ 246,877	$ 903,480

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Lighting Redesign and Equipment Incentive - Government						
Number of Units - Total # of Buildings - ECM912	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions per Building	$ 168	$ 1,462	$ 2,913	$ 3,200	$ 2,472	$ 10,214
In-depth Blueprint & Layout Verification (1/3 verification)	$ 56	$ 487	$ 971	$ 1,067	$ 824	$ 3,405
Incentive Amount - Redesign Incentive - ECM912	$ 2,735	$ 14,216	$ 22,962	$ 22,962	$ 11,481	$ 74,356
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 2,227	$ 5,663	$ 6,666	$ 6,866	$ 21,423
In-Depth Verification & Site Visit (1/3)	$ -	$ 742	$ 1,888	$ 2,222	$ 2,289	$ 7,141
Expense Budget Site Visits (1/3)	$ -	$ 148	$ 378	$ 444	$ 458	$ 1,428
Incentive for Typical Lighting Project in Existing Bldg - Office - ECM802	$ -	$ 1,124	$ 3,044	$ 3,478	$ 3,478	$ 11,125
Incentive for Typical Lighting Project in Existing Bldg - Health - ECM842	$ -	$ 520	$ 1,213	$ 1,386	$ 1,386	$ 4,506
Incentive for Typical Lighting Project in Existing Bldg - Education - ECM852	$ -	$ 1,778	$ 4,148	$ 4,741	$ 4,741	$ 15,409
Incentive for Typical Lighting Project in Existing Bldg - Recreation - ECM872	$ -	$ 497	$ 1,161	$ 1,326	$ 1,326	$ 4,310
Incentive for Typical Lighting Project in Existing Bldg - Warehouse - ECM882	$ -	$ 339	$ 790	$ 903	$ 903	$ 2,934
Incentive for 12W LED A19 Bulb Installed as Part of Projects - ECM922	$ -	$ 3,227	$ 7,530	$ 8,606	$ 8,606	$ 27,970
Incentive for 8W LED A19 Bulb Installed as Part of Projects - ECM932	$ -	$ 4,590	$ 10,710	$ 12,240	$ 12,240	$ 39,780
Incentive for LED MR16 Bulbs Installed as Part of Projects - ECM942	$ -	$ 2,988	$ 6,973	$ 7,969	$ 7,969	$ 25,899
Incentive for LED PAR30 Bulbs Installed as Part of Projects - ECM952	$ -	$ 4,781	$ 11,156	$ 12,750	$ 12,750	$ 41,438
Incentive for LED PAR38 Bulbs Installed as Part of Projects - ECM962	$ -	$ 3,477	$ 8,114	$ 9,273	$ 9,273	$ 30,136
Incentive for Spot or task lighting Installed as Part of Projects - ECM972	$ -	$ 1,195	$ 2,789	$ 3,188	$ 3,188	$ 10,359
Subtotal	$ 2,959	$ 43,799	$ 92,402	$ 102,422	$ 90,250	$ 331,832
New Construction Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ 25,069	$ -	$ 48,010
Number of Units - Total # of Buildings	$ -	$ 272	$ 1,259	$ 2,017	$ 2,374	$ 5,922
Expense Budget Site Visits	$ -	$ 18	$ 84	$ 134	$ 158	$ 395
$ Equipment Incentive. Baseline-25% - ECM89	$ -	$ 2,989	$ 13,449	$ 20,920	$ 23,909	$ 61,266
$ Equipment Incentive. Baseline-40% - ECM90	$ -	$ 1,245	$ 5,604	$ 8,717	$ 9,962	$ 25,527
Subtotal	$ 22,942	$ 4,524	$ 20,395	$ 56,857	$ 36,403	$ 141,120

Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
New Construction Incentive - Government						
Number of Units - Total # of Buildings	$ -	$ 146	$ 678	$ 1,086	$ 1,278	$ 3,189
Expense Budget Site Visits	$ -	$ 10	$ 45	$ 72	$ 85	$ 213
$ Equipment Incentive. Baseline-25% - ECM892	$ -	$ 966	$ 4,345	$ 6,759	$ 7,724	$ 19,794
$ Equipment Incentive. Baseline-40% - ECM902	$ -	$ 402	$ 1,810	$ 2,816	$ 3,218	$ 8,247
Subtotal	$ -	$ 1,524	$ 6,878	$ 10,733	$ 12,307	$ 31,442
Energy Star Computer Incentive						
Initial Set-up and Preparation	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # Desktops and Laptops	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per 3 Units	$ 1,239	$ 8,085	$ 13,587	$ -	$ -	$ 22,911
Incentive for ENERGY STAR Desktop Computer and Monitor	$ 1,339	$ 8,477	$ 13,831	$ -	$ -	$ 23,647
Incentive for ENERGY STAR Laptop	$ 297	$ 1,884	$ 3,074	$ -	$ -	$ 5,255
Subtotal	$ 25,817	$ 18,446	$ 30,492	$ -	$ -	$ 74,754
Energy Star Computer Incentive - Government						
Number of Units - Total # Desktops and Laptops	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per 3 Units	$ 4,957	$ 32,339	$ 54,347	$ -	$ -	$ 91,643
Incentive for ENERGY STAR Desktop Computer and Monitor	$ 3,212	$ 20,345	$ 33,195	$ -	$ -	$ 56,753
Incentive for ENERGY STAR Laptop	$ 714	$ 4,521	$ 7,377	$ -	$ -	$ 12,612
Subtotal	$ 8,884	$ 57,206	$ 94,919	$ -	$ -	$ 161,008
High-Efficiency Refrigeration Incentive						
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 45,654	$ 6,759	$ 41,547	$ 14,264	$ 108,224
Expense Budget Site Visits	$ -	$ 3,652	$ 541	$ 3,324	$ 1,141	$ 8,658
$ Equipment Incentive ECM98	$ -	$ -	$ 40,075	$ -	$ 40,075	$ 80,149
$ Equipment Incentive ECM98	$ -	$ -	$ 81,566	$ -	$ 81,566	$ 163,133
Subtotal	$ 22,942	$ 49,306	$ 128,941	$ 44,871	$ 137,047	$ 383,105

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Commercial DSM Program Design Incl. Government - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
High-Efficiency Refrigeration Incentive - Government						
Number of Units - Total # of Buildings	$ -	$ -	$ -	$ -	$ -	$ -
Process Transaction per Building	$ -	$ 25,503	$ -	$ 27,056	$ -	$ 52,559
Expense Budget Site Visits	$ -	$ 2,040	$ -	$ 2,164	$ -	$ 4,205
$ Equipment Incentive ECM100	$ -	$ -	$ 9,904	$ -	$ 9,904	$ 19,808
Subtotal	$ -	$ 27,543	$ 9,904	$ 29,221	$ 9,904	$ 76,572
Engagement, Training and Communication						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 13,765	$ -	$ -	$ -	$ -	$ 13,765
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 4,591	$ 4,729	$ 4,871	$ 5,017	$ 19,209
Direct Engagement Workforce w/ Experienced Personnel	$ 65,280	$ 80,422	$ 70,614	$ 61,542	$ 63,389	$ 341,247
Expense budget - Communication, Trips, Materials	$ 24,000	$ 32,960	$ 33,949	$ 34,967	$ 36,016	$ 161,892
Expense Budget Trade Event	$ -	$ 25,750	$ 26,523	$ 27,318	$ 28,138	$ 107,728
Event Organization Related with the Trade Event	$ -	$ 22,957	$ 23,646	$ 24,355	$ 25,086	$ 96,044
Expense Budget Training	$ 16,000	$ 16,480	$ 16,974	$ -	$ -	$ 49,454
Event Organization - Training	$ 8,915	$ 9,183	$ 9,458	$ -	$ -	$ 27,557
Consulting Services to Deliver Training	$ 16,194	$ 16,680	$ 17,180	$ -	$ -	$ 50,054
Subtotal	$ 144,154	$ 209,024	$ 203,073	$ 153,054	$ 157,646	$ 866,951
Engagement, Training and Communication - Government (Marginal)						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 5,735	$ -	$ -	$ -	$ -	$ 5,735
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 1,148	$ 1,182	$ 1,218	$ 1,254	$ 4,802
Direct Engagement Workforce w/ Experienced Personnel	$ 17,920	$ 21,094	$ 16,295	$ 11,190	$ 11,525	$ 78,025
Expense budget - Communication, Trips, Materials	$ 6,000	$ 8,240	$ 8,487	$ 8,742	$ 9,004	$ 40,473
Subtotal	$ 29,655	$ 30,482	$ 25,965	$ 21,149	$ 21,784	$ 129,035
Program Management, Administration and Tracking						
Program Management	$ 64,000	$ 69,216	$ 67,898	$ 69,935	$ 72,033	$ 343,081
Tracking System Design, Then Servicing	$ 16,059	$ -	$ -	$ -	$ -	$ 16,059
Tracking System Maintenance	$ 892	$ 1,837	$ 1,892	$ 1,948	$ 2,007	$ 8,575
Feed tracking system and reporting	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Third-party M&V	$ -	$ 77,250	$ -	$ -	$ 140,689	$ 217,939
Subtotal	$ 87,637	$ 157,485	$ 79,248	$ 81,625	$ 224,762	$ 630,758
TOTAL	$ 394,965	$ 705,294	$ 927,996	$ 764,824	$ 936,980	$ 3,730,059

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Residential DSM Program Design - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
LED Lighting and Automotive Heater Timer Rebates						
Build Transactional and Operational Infrastructure	$ 11,471	$ -	$ -	$ -	$ -	$ 11,471
Number of Units Automotive Heater Timers - ECM151	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions - ECM151 (1 unit/transaction)	$ -	$ 1,407	$ 2,309	$ 2,378	$ 2,449	$ 8,543
$ Equipment Incentive. ECM151	$ -	$ 1,366	$ 2,176	$ 2,176	$ 2,176	$ 7,894
Build Transactional and Operational Infrastructure	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Number of Units - 12W LED A19 Bulbs - ECM24	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - 8W LED A19 Bulb - ECM60	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED MR16 Bulbs - ECM61	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED PAR30 Bulbs - ECM62	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - LED PAR38 Bulbs - ECM63	$ -	$ -	$ -	$ -	$ -	$ -
Number of Units - Spot or Task Lighting - ECM44	$ -	$ -	$ -	$ -	$ -	$ -
Process Transactions (5 units per transaction)	$ 3,136	$ 13,787	$ 14,201	$ 14,627	$ 15,065	$ 60,816
Phone verification (1/20 spot check)	$ 874	$ 3,841	$ 3,956	$ 4,075	$ 4,197	$ 16,944
Site visit (1/100 verification)	$ 699	$ 3,073	$ 3,165	$ 3,260	$ 3,358	$ 13,555
Expense Budget Site Visits	$ 314	$ 1,379	$ 1,420	$ 1,463	$ 1,507	$ 6,082
Update the incentive list (once per year)	$ -	$ 2,296	$ 2,365	$ 2,436	$ 2,509	$ 9,604
Incentive Amount - 12W LED A19 Bulbs - ECM24	$ 6,276	$ 26,183	$ 26,183	$ 26,183	$ 26,183	$ 111,008
Incentive Amount - 8W LED A19 Bulb - ECM60	$ 4,184	$ 17,455	$ 17,455	$ 17,455	$ 17,455	$ 74,005
Incentive Amount - LED MR16 Bulbs - ECM61	$ 547	$ 2,586	$ 2,586	$ 2,586	$ 2,586	$ 10,891
Incentive Amount - LED PAR30 Bulbs - ECM62	$ 272	$ 1,574	$ 1,574	$ 1,574	$ 1,574	$ 6,567
Incentive Amount - LED PAR38 Bulbs - ECM63	$ 198	$ 1,181	$ 1,181	$ 1,181	$ 1,181	$ 4,921
Incentive Amount - Spot or Task Lighting - ECM44	$ 87	$ 408	$ 408	$ 408	$ 408	$ 1,717
Subtotal	$ 50,998	$ 76,535	$ 78,978	$ 79,801	$ 80,648	$ 366,960

Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Residential DSM Program Design - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
Low-Cost Energy Efficient Products						
Initial Set-up and Preparation	$ 17,206	$ -	$ -	$ -	$ -	$ 17,206
Low-cost EE P. - Procurement and Inventory Management	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Low-cost EE P. - Scorecard Crunching, Analysis & Reporting	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Expense Budget: Shipping	$ 6,000	$ 8,240	$ 8,487	$ 8,742	$ 9,004	$ 40,473
Cost of Giveaways - Pilot 12W LED A19 Bulbs - ECM242	$ 2,640	$ 2,640	$ 2,640	$ 2,640	$ 2,640	$ 13,200
Cost of Giveaways - Pilot 8W LED A19 Bulb - ECM602	$ 1,860	$ 1,860	$ 1,860	$ 1,860	$ 1,860	$ 9,300
Cost of Giveaways - Pilot LED MR16 Bulbs - ECM612	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
Cost of Giveaways - Pilot LED PAR30 Bulbs - ECM622	$ 1,920	$ 1,920	$ 1,920	$ 1,920	$ 1,920	$ 9,600
Cost of Giveaways - Pilot LED PAR38 Bulbs - ECM632	$ 1,060	$ 1,060	$ 1,060	$ 1,060	$ 1,060	$ 5,300
Cost of Giveaways - Pilot Spot or Task Lighting - ECM442	$ 150	$ 150	$ 150	$ 150	$ 150	$ 750
Cost of Giveaways - Pilot Ultra Low-flow Showerheads - ECM092	$ 480	$ 640	$ 480	$ 320	$ 320	$ 2,241
Cost of Giveaways - Pilot Power Bars for PCs and TVs - ECM112	$ 3,000	$ 3,000	$ 2,000	$ 2,000	$ 1,500	$ 11,500
Cost of Giveaways - Pilot DHW Tank Insulation - ECM182	$ 1,503	$ 2,255	$ 2,255	$ 1,503	$ 1,503	$ 9,019
Cost of Giveaways - Pilot DHW Pipe Insulation - ECM202	$ 32	$ 47	$ 47	$ 32	$ 32	$ 190
Cost of Giveaways - Pilot Motion Detectors - Indoor and Outdoor -	$ 1,376	$ 1,376	$ 918	$ 918	$ 688	$ 5,276
Cost of Giveaways - Pilot Auto Heater Timers - ECM152	$ 1,125	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 10,125
Cost of Giveaways - Pilot Prog. Thermostats (Central) - ECM142	$ 625	$ 1,250	$ 938	$ 625	$ 625	$ 4,063
Cost of Giveaways - Pilot Prog. Thermostats - ECM212	$ 14,271	$ 25,689	$ 22,834	$ 17,126	$ 11,417	$ 91,338
Cost of Giveaways - Pilot E-Star TVs - ECM062	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 2,250	$ 11,250
Cost of Giveaways - Pilot E-Star Printers and Fax - ECM082	$ 800	$ 800	$ 800	$ 800	$ 800	$ 4,000
Research and Creation of Materials - Early Support & Training	$ 17,206	$ -	$ -	$ -	$ -	$ 17,206
Research and Creation of Materials - Bulk of the Work	$ 23,040	$ 31,642	$ 32,591	$ 33,569	$ 34,576	$ 155,417
Research and Creation of Materials - Supervision	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Expense Budget Related with Materials	$ 30,000	$ 41,200	$ 42,436	$ 43,709	$ -	$ 157,345
Subtotal	$ 147,605	$ 156,818	$ 155,291	$ 151,699	$ 103,698	$ 715,111

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Yukon Energy Corporation and Yukon Electrical Company Limited
YEC YECL Residential DSM Program Design - Master Budget

Cost Items	Cost Y1	Cost Y2	Cost Y3	Cost Y4	Cost Y5	Total Cost per Item
New-construction CCHP and GSHP Initiative						
Coordination of the Pilot Projects (3-elem. DHW, CCHP, GSHP)	$ 8,915	$ 18,366	$ 18,917	$ -	$ -	$ 46,198
Heavy incentive - Pilot CCHP ECM032	$ 5,000	$ -	$ -	$ 5,000	$ -	$ 10,000
Heavy incentive - Pilot GSHP ECM372	$ -	$ 9,000	$ 9,000	$ -	$ -	$ 18,000
Project-level M&V of Pilot Projects: % of Project Costs	$ -	$ 3,600	$ 3,600	$ -	$ -	$ 7,200
Build Transactional and Operational Infrastructure	$ -	$ -	$ -	$ 25,069	$ -	$ 25,069
Process Transactions CCHP - ECM03	$ -	$ -	$ -	$ 5,245	$ 5,402	$ 10,648
Process Transactions GSHP - ECM37	$ -	$ -	$ -	$ 874	$ 900	$ 1,775
Expense Budget Site Visits	$ -	$ -	$ -	$ 1,530	$ 1,576	$ 3,106
$ Equipment Incentive. CCHP - ECM03	$ -	$ -	$ -	$ 15,000	$ 15,000	$ 30,000
$ Equipment Incentive. GSHP - ECM37	$ -	$ -	$ -	$ 3,500	$ 3,500	$ 7,000
Subtotal	$ 13,915	$ 30,966	$ 31,517	$ 56,218	$ 26,379	$ 158,994
Engagement, Education and Communication						
Initial Marketing, Engagement, Educ. and Comm. Planning	$ 22,942	$ -	$ -	$ -	$ -	$ 22,942
Direct Engagement Workforce w/ Junior Personnel	$ 53,760	$ 73,830	$ 76,045	$ 78,327	$ 80,676	$ 362,639
Direct Engagement Workforce w/ Experienced Personnel	$ 6,687	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 45,104
Annual Marketing, Engagement, Educ. and Comm. Planning	$ -	$ 5,739	$ 5,911	$ 6,089	$ 6,271	$ 24,011
Expense budget - Communication, Trips, Materials	$ 30,000	$ 41,200	$ 42,436	$ 43,709	$ 45,020	$ 202,365
Subtotal	$ 113,388	$ 129,953	$ 133,851	$ 137,867	$ 142,003	$ 657,061
Program Management, Administration and Tracking						
Program Management	$ 83,200	$ 59,328	$ 54,318	$ 55,948	$ 57,626	$ 310,420
Tracking System Design, Then Servicing	$ 11,471	$ 3,544	$ -	$ 7,521	$ 7,746	$ 30,282
Tracking System Maintenance	$ 892	$ 1,837	$ 1,892	$ 1,948	$ 2,007	$ 8,575
Feed tracking system and reporting	$ 8,024	$ 9,183	$ 9,458	$ 9,742	$ 10,034	$ 46,442
Third-party EM&V	$ -	$ 66,950	$ -	$ -	$ 112,551	$ 179,501
Subtotal	$ 103,586	$ 140,842	$ 65,668	$ 75,159	$ 189,964	$ 575,220
TOTAL	$ 429,492	$ 535,113	$ 465,305	$ 500,743	$ 542,692	$ 2,473,346

YUB-YECL-30

Reference: General Service Programs, Yukon Five Year Demand Side Management Plan, page 20

The Board wants to better understand the General Service programs proposed in the Five Year Demand Side Management Plan.

Request:

(a) With regard to the Lighting Redesign and Equipment Incentive, how much of the total costs of these retrofits will the rebates cover?

(b) With regard to the High Efficiency Refrigeration Incentive, how much of the total costs of these retrofits will the rebates cover?

(c) On page 22 of the DSM plan, YEC and YECL noted that they "will provide extensive refrigeration-specific technical assistance to identify the opportunities, to develop the projects, to manage the construction works, and to measure and monitor the performance of the projects." Please explain how or when YEC and YECL developed the technical expertise in refrigeration specifics.

(d) With regard to the Energy Star Computer Incentive, how much of the total costs of these products will the rebates cover? Are any Yukon-based companies or organizations eligible for this program?

(e) With regard to the New Construction Incentive, how much of the total costs of these buildings will the rebates cover? Are any Yukon-based companies or organizations eligible for this program?

Response:

(a) The Lighting Redesign and Equipment Program is based on an incentive level for a dollar per square foot with a cap. This program also includes an added prescriptive incentive for the installation of LED fixtures and lights, which is also based on a dollar amount per unit and is consistent with the residential LED program. The total incentive amount for this program are as follows (taken from page 33 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 20: Budget – Lighting Redesign and Equipment Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$4	$96	$213	$239	$222	$773
Non-Incentive:	$72	$56	$46	$50	$91	$314
Total:	$76	$152	$259	$289	$312	$1,087

Exhibit 11: Budget – Lighting Redesign and Equipment Incentive including Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$6	$135	$294	$327	$299	$1,062
Non-Incentive:	$81	$77	$66	$72	$127	$425
Total:	$88	$213	$360	$400	$427	$1,487

(b) The High Efficiency Refrigeration Program is based on an incentive level for a dollar per kilowatt hour rate, based on annual savings. The total incentive amount for this program are as follows taken *(*from page 42 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 23: Budget – High Efficiency Refrigeration Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$0	$122	$0	$122	$243
Non-Incentive:	$34	$69	$17	$55	$43	$218
Total:	$34	$69	$139	$55	$165	$461

Exhibit 34: Budget – High Efficiency Refrigeration Incentive including Government Buildings

$1,000s						
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$0	$132	$0	$132	$263
Non-Incentive:	$36	$100	$19	$86	$49	$290
Total:	$36	$100	$151	$86	$180	$553

(c) Given the relatively small number of potential participants, energy engineers will be engaged by the utilities to build tailor-made technical assistance packages for each participant. These packages may include an initial walk-through audit, an investment grade audit, procurement support, project management and/or project performance measurement and verification. The technical assistance budget will be commensurate with the estimated savings.

(d) All Yukon Electrical and Yukon Energy general service account holders will be eligible for the Energy Star Computer incentive. Eligibility for government general service accounts will be determined based on the YUB decision on the inclusion of government accounts. The incentive level is fixed, the product cost is variable. This allows for participants to choose the most appropriate product for their application (taken from page 45 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 39: Prescriptive List of ENERGY STAR Computer Conservation Measures for Non-Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM101	ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	95%	$0.00/unit	4.0 yr	$30.00/unit
ECM102	ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	95%	$0.00/unit	4.0 yr	$10.00/unit

Exhibit 40: Prescriptive List of ENERGY STAR Computer Conservation Measures for Government Buildings

ID	Measure Short Name	Gross Annual Consumption Savings	Gross Coincident Peak Savings	Net-to-Gross Ratio	Measure Cost	Measure Lifetime	Level of Incentive
ECM1012	Gov. ES Desktop Computer and Monitor	148.0 kWh/unit	0.027 kW/unit	55%	$0.00/unit	4.0 yr	$18.00/unit
ECM1022	Gov. ES Laptop Computer	41.0 kWh/unit	0.007 kW/unit	55%	$0.00/unit	4.0 yr	$6.00/unit

(e) All Yukon Energy and Yukon Electrical general service account holders will be eligible for the New Construction Incentive. Eligibility for government general service accounts will be determined based on the YUB decision on the inclusion of government accounts. The incentive will be determined using a dollar per square foot rate if the building complies with a certain standard. The standard will be designed to be slightly more stringent than model national energy building code minus 25 percent and the City of Whitehorse's building and plumbing bylaw. The total incentive amount for this program are as follows (taken from page 57 of Appendix E of the *Yukon Five Year Demand Side Management Plan* included in the Application):

Exhibit 58: Budget – Electricity-Efficient New Construction Incentive excluding Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$4	$19	$30	$34	$87
Non-Incentive:	$27	$7	$5	$31	$13	$83
Total:	$27	$12	$24	$61	$47	$170

Exhibit 59: Budget – Electricity-Efficient New Construction Incentive including Government Buildings

	$1,000s					
	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Incentive:	$0	$6	$25	$39	$45	$115
Non-Incentive:	$28	$9	$6	$33	$16	$93
Total:	$28	$15	$32	$72	$61	$208

YUB-YECL-31

Reference: Business risk, YECL Application, Section 8-Return on Rate Base, Page 8-4, Lines 13-15

Consistent with the various business risk factors identified in its 2008-2009 GRA, Yukon Electrical's ongoing business risks encompass market demand, operational costs, physical hazards and regulation."

The Board wants to understand how the business risks identified in the quote have changed since the 2008-2009 GRA

Request:

(a) Is it the position of YECL that it faces greater business risks than it did in the 2008-09 GRA? If yes, explain why.

(b) Please discuss how the following risks have changed since the 2008-09 GRA:

i. Market demand

ii. Operational costs

iii. Physical hazards

iv. Regulation

(c) For each of the above risk factors, please quantify the impact of the change in risk.

Response:

(a - c) At the outset, it should be noted that Yukon Electrical's request for an increased common equity ratio arises primarily from the recognition in other jurisdictions that similar increases have been approved for other utilities which has Yukon Electrical has been compared or benchmarked against. Since 2008, BCUC's benchmark utility common equity ratio has increased from 35.01% to 38.5%, Northland Utilities (Yellowknife)'s common equity ratio has increased

from 39.57% to 43.5%, and Northland Utilities (NWT)'s common equity ratio has increased from 40% to 44%. These changes in common equity ratios reflect increases of 3.49%, 3.93% and 4.00%, respectively. Even in the absence of increased business risk, Yukon Electrical's requested 4% increase to its common equity ratio is consistent with the approved increases to its affiliates in the Northwest Territories, with which Yukon Electrical shares similar business risks, and is supported by the increase to the BCUC's benchmark utility. Please also refer to YUB-YECL-33(b) for the common equity ratios requested by the British Columbia non-benchmark utilities involved with Stage 2 of the BCUC GCOC process.

Further to the above, it is Yukon Electrical's position its business risks for this Application remain largely consistent with those assessed in 2008 as part of its 2008-2009 GRA. At that point in time, Yukon Electrical's expert witness concluded that Yukon Electrical's business risks were higher than those of the typical Canadian electricity distribution utility and higher than average within the spectrum of Canadian utilities. Further to this position, however, Yukon Electrical notes the following areas where its business risks have increased modestly since 2008.

Market Demand:

Market demand risk relates to those factors that can lead to annual volatility in electricity sales and loss of customers. Between 2008 and 2012, Whitehorse residential annual use per customer has increased from 10,489 kWh in 2008 to 11,128 kWh (Normalized 2012 Actual). This increase appears to be, in large part, due to a resurgence of electric space heating in the Whitehorse area. While Yukon Electrical has incorporated this increase into its 2013-2015 sales forecast, there is now added risk of this space heating electrical load shifting to home heating fuel, propane or wood. Homes that are supplementing fuel heating with portable electric space heaters can choose to not do so. For purposes of quantification, this 639 kWh change in UPC impacted Yukon Electrical's 2013 sales revenue forecast by approximately $850,000 (639 X 10,792 X .1237).

Since 2008, approximately 2,500,000 kWh of secondary sales electric load (related to heating and processing) has been converted into primary load. This new primary load has been incorporated into Yukon Electrical's primary sales forecast for 2013-2015 and annually represents approximately $400,000 of Yukon Electrical's commercial sales revenue forecast. Given that this load is

convertible to a fossil fuel solution, there is now increased risk to Yukon Electrical of decreased primary sales due to fuel switching.

As part of this GRA, Yukon Electrical and Yukon Energy are jointly proposing a Demand Side Management (DSM) program. This program, which was not in place in 2008, will increase emphasis on energy efficiency and conservation. While Yukon Electrical has incorporated the forecast impact of the program into its forecast (please refer to WL-YECL-8(a)), overall sales forecast risk has increased as a result of the introduction of the program. Should the program be more successful than anticipated, it will reduce Yukon Electrical's actual sales as compared to forecast.

In its 2008-2009 GRA, Yukon Electrical did not forecast any sales to industrial customers. In this Application, Yukon Electrical is forecasting industrial sales to one customer, Whitehorse Copper Tailing (WHCT). As it continues to be unclear as to whether or not and when this customer may connect and what the ultimate amount of load will be, Yukon Electrical has requested a deferral account that will address any additional earnings or decreases in earnings as a result of the actual load being higher or lower than forecast. Assuming this deferral is approved by the Board, there is no change in market demand risk related to industrial sales in this Application as compared to the 2008-2009 GRA.

Operational Costs:

As detailed in the following table, Yukon Electrical is forecasts a shift in the mix of its assets towards generation during the test period. The presence of generation assets in rate base generally increases the Yukon Electrical's business risk relative to a pure distribution utility, as the operational risks associated with generation exceed those of distribution "wires" operations.

	Actual		GRA		
	2008	**2012**	**2013**	**2014**	**2015**
Generation	14%	13%	16%	18%	19%
Distribution	79%	81%	77%	75%	74%
Other	7%	6%	7%	7%	7%
Total	100%	100%	100%	100%	100%

Since the 2008-2009 GRA, Yukon Electrical has obtained a 25-year water licence for operation of the Fish Lake Hydro System which stipulates additional monitoring, reporting and operational requirements as compared to the previous licence. Please refer to YUB-YECL-53 (to be filed August 29) for an overview of the new requirements associated with this licence. This change has increased Yukon Electrical's operational risk with respect to hydro generation at the Fish Lake hydro plant.

Yukon Electrical, as part of this Application, is also proposing its Watson Lake Bi-Fuel Project whereby it will be possible to fuel the generators in Watson Lake with both diesel fuel and natural gas. This project is subject to new permitting and oil and gas regulations that Yukon Electrical must follow in order to provide service to its customers. The project offers customers benefits related to emissions reduction, fuel cost savings and diversity. The project is, however, a first of its kind project in the north and the steps necessary to achieve approvals are significant and contain a level of uncertainty. The Watson Lake Bi-Fuel Project will increase Yukon Electrical's operational risk as compared to 2008.

YUB-YECL-32

Reference: Return on equity, YECL Application, Schedule 8.1

The Board wants to confirm the return on equity for 2008 to 2012.

Request:

(a) Please confirm the following returns from Schedule 8.1:

(i) 2008: 7.03%
(ii) 2009: 11.35%
(iii) 2010: 10.54%
(iv) 2011: 10.74%
(v) 2012: 10.18%

(b) Please confirm that the average ROE for the years 2008 to 2012 was 9.968%.

(c) Please discuss the need for an increase in approved ROE to 9.21%, given that YECL has been earning an average of 9.68% when the approved ROEs in the past five years were lower than the requested ROE.

Response:

(a) Confirmed.

(b) Yukon Electrical confirms its average ROE for the years 2008 to 2012 was 9.968%. The BCUC GCOC Benchmark average for the same period, including the awarded 0.46% risk premium, was 9.68%[1].

(c) As detailed throughout this Application, Yukon Electrical is experiencing significant cost pressures and capital requirements that require it to come forward to the Board to ensure that it has an opportunity to continue to provide safe and reliable service to its customers while affording the company an opportunity to earn a fair return for the test period 2013-2015.

[1] Average BCUC Benchmark for the period 2008-2012 was 9.22%: 2008 (8.62%); 2009 (8.99% (8.47% + 9.50% (effective July 1, 2009)); 2010 (9.50%); 2011 (9.50%); 2012 (9.50%).

The requested ROE of 9.21% is linked to the recently approved BCUC GCOC benchmark rate of 8.75% plus a risk premium of 0.46%. As stated in Decision 2009-2, the Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

YUB-YECL-33

Reference: Common equity ratio, YECL Application, Section 8 – Return on Rate Base, page 8-6

Yukon Electrical is requesting to increase its common equity ratio from the current level of 40% to 44% for each of 2013, 2014 and 2015.

Although the BCUC increased its common equity ratio for its benchmark utility after 2008, it also lowered the common equity ratio effective January 1, 2013.

Request:

(a) Please confirm that the BCUC reduced the common equity ratio for its benchmark utility from 40% to 38.5% in Order G-75-13.

(b) Given that the BCUC has determined that a lower common equity ratio is appropriate from 2013, please discuss the differences for YECL which make an increase of 4% to its common equity ratio more reasonable than the benchmark utility for BCUC.

Response:

(a) Yukon Electrical confirms the following changes with respect to the BCUC common equity ratio for its benchmark utility have taken place since the Yukon Utilities Board Decision 2009-2 (February 12, 2009):

Common equity ratio as of February 12, 2009:	35.0%[1]
Common equity ratio effective January 1, 2010:	40.0%[2]
Common equity ratio effective January 1, 2013:	38.5%[3]

(b) Yukon Electrical's request for a 9.21% ROE and a common equity ratio of 44% is based on the expert evidence it filed in its 2008-2009 GRA that concluded Yukon Electrical's business risks are: (1) higher than those of the typical

[1] Per BCUC Order G-14-06 dated March 2, 2006, that stated the appropriate common equity component allowed in the capital structure for the benchmark utility, Terasen Gas Inc. (TGI) is 35%. This Order also addressed the appropriate common equity component allowed in the capital structure of Terasen Gas (Vancouver Island) (TGVI) which was set at 40%.
[2] Per BCUC Order G-158-09 dated December 16, 2009.
[3] Per BCUC Order G-75-13 dated May 10, 2013.

Canadian distribution utility; (2) higher than average within the spectrum of Canadian utilities; and (3) that the capital structure for Yukon Electrical should respect the stand-alone principle. Please refer to YUB-YECL-33(b) Attachment 1 for a copy of the expert evidence filed in the 2008-2009 GRA. As detailed in YUB-YECL-31, it is Yukon Electrical's position that its business risk has increased modestly since 2008.

Regardless of Yukon Electrical's assessment that its business risk has increased modestly since 2008, regulatory decisions and processes in British Columbia and the Northwest Territories have occurred since 2008 that support Yukon Electrical's requests in this Application.

Firstly, in British Columbia, the BCUC has reaffirmed the long history and importance of the stand-alone principle in Canadian utility regulation as part of its BCUC Generic Cost of Capital Proceeding (Stage 1) Decision May 10, 2013 (page 100). As detailed in this Application, Stage 1 of this proceeding has now concluded with Order G-75-13 stating the benchmark utility, FortisBC Energy Inc. (FEI), is to have an ROE of 8.75% and a common equity ratio of 38.5% for the years 2013-2015 subject to any adjustments in 2014 or 2015 as a result of the Automatic Adjustment Mechanism (AAM).

Now that Stage 1 has been completed in British Columbia, Stage 2, dealing with business risks of non-benchmark utilities, has begun. A summary of the requested ROEs and common equity ratios in that proceeding is as follows:

	ROE	Equity Ratio
FortisBC Inc. (Electricity)	9.25%-9.50%	40%
FortisBC Energy (Vancouver Island)	9.25%	43.50%
FortisBC Energy (Whistler)	9.50%	45%
Pacific Northern Gas Ltd.	9.75%	50%
Pacific Northern Gas (N.E.) Ltd.	9.50%	45%

Further to the situation in British Columbia, the Northwest Territories Public Utilities Board approved common equity ratios for Northland Utilities (Yellowknife) and Northland Utilities (NWT) of 43.5% and 44%, respectively, for the test years 2008-2010 as well as 2011-2013. As stated in Yukon Electrical's 2008-2009 expert evidence, Yukon Electrical shares similar business risks with Northland Utilities (Yellowknife).

For purposes of this Application, it is Yukon Electrical's position that its ROE and capital structure should be based on its evidence that (i) its business risks are higher than the typical distribution utility; and (ii) applicability of the stand-alone principle in the Yukon.

In order to provide perspective on the various companies that are involved in the Stage 2 process in British Columbia as well as the Northland companies that share similar risks to Yukon Electrical, please refer to the following table that is based on information obtained from the BCUC Stage 2 process as well as Northland's 2012 statistics:

	FortisBC Energy Inc. (BCUC Benchmark)	Yukon Electrical	FortisBC Inc.	FortisBC Energy (Vancouver Island)	FortisBC Energy (Whistler)	Pacific Northern Gas Ltd.	Pacific Northern Gas (N.E.) Ltd.	Northland Utilities (Yellowknife)	Northland Utilities (NWT)
Type of Utility	Gas Distribution Company	Electric Distribution & Generation Company	Electric Generation, Transmission and Distribution	Gas Distribution Company	Gas Distribution Company	Gas Transmision & Distribution Company	Gas Distribution Company	Electric Distribution Company	Electric Generation, Transmission & Distribution Company
Service Area	Lower Mainland, Inland, Columbia and Revelstoke (propane)	Whitehorse and area, Watson Lake and area, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Old Crow, Beaver Creek, Destruction Bay, Burwash Landing and Swift River	South Central Interior of British Columbia	Vancouver Island, Sunshine Coast, and Powell River	Whistler	West Central portion of British Columbia from Summit River to west coast	Northwest British Columbia Fort St. John / Dawson Creek areas	Yellowknife and N'Dilo	Hay River, Trout Lake, Wekweeti, Kakisa, Dory Point, Fort Providence and the Katio'odeeche First Nation
Common Equity Ratio for 2013 - (1) Approved or (2) Applied For	38.5% (1)	44% (2)	40% (2)	43.5% (2)	45% (2)	50% (2)	45% (2)	43.5% (1)	44% (1)
ROE for 2013 (1) Approved or (2) Applied For	8.75% (1)	9.21% (2)	9.25%-9.50% (2)	9.25% (2)	9.5% (2)	9.75% (2)	9.5% (2)	9.3%(1)	9.3% (1)
2012 Rate Base ($ millions)	$2,692.8	$60.0	$1,088.5	$778.7	$41.7	$127.9	$45.0	$40.7	$15.2
2012 Sales/Transportation Volumes	178,735 TJs	316 GWh	3,144 GWh	38,083 TJs	686 TJs	4,053 Tjs	5,422 Tjs	159 GWh	35 GWh
2012 Number of Customers	893,040	16,702	113,915	101,098	2,612	20,496	19,379	8,140	2,718

It is Yukon Electrical's position, based on its previously filed business risk expert evidence in 2008-2009 GRA and as updated by Yukon Electrical management in in YUB-YECL-31, its overall business risk is more aligned with the referenced smaller distribution utilities in British Columbia and the Northwest Territories as opposed to the British Columbia gas and electric utilities with billion dollar rate bases. For these reasons, as well as reference to the stand-alone principle, the requested 9.21% ROE and common equity ratio of 44% are reasonable for purposes of this Application.

Yukon Electrical Company Limited

Prepared Testimony

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, MD. 20814
April 2008

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of, and a senior consultant with, Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, oil and gas pipelines, and telephone companies in more than 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix A.

Yukon Electrical Company Limited ("Yukon Electrical") has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity (ROE) for the Company's 2008 and 2009 test years, using, for the express purpose of these two test years, the benchmark return on equity established by the Alberta Energy and Utilities Board (EUB)[1] as a point of departure.

In that context, I have estimated the capital structure that would fully reflect the business risks of Yukon Electrical. Based on my analysis, the common equity ratio that would fully compensate for the business risks of Yukon Electrical lies at the upper end of a range of 47.5% to 52.5%.

At a common equity ratio of 52.5%, the allowed return on equity for Yukon Electrical should be equal to that applicable to an average risk Canadian utility, that is, a benchmark return on equity. For the express purpose of this proceeding, I recommend adopting the benchmark return on equity derived in the EUB's Generic Cost of Capital Decision 2004-052 (July 2, 2004), as adjusted for changes in interest rates. The benchmark return on

[1] Now the Alberta Utilities Commission or "AUC".

equity adopted by the EUB under its generic cost of capital automatic adjustment mechanism for 2008 was 8.75%, based on a long-term Canada bond yield of 4.55%.

With respect to the benchmark return on equity for test years 2008-2009, I recommend that the Yukon Utilities Board ("the Board"):

1. Adopt a single return on equity for both test years, based on the forecast average long-term Government of Canada bond yield of 4.5%; and,

2. Apply the EUB's automatic adjustment formula to arrive at a benchmark ROE for 2008-2009.

Since the forecast average long-term Government of Canada bond yield for 2008-2009, at 4.5%, is virtually identical to the forecast relied on by the EUB to determine the allowed ROE for 2008, the application of the automatic adjustment formula produces a benchmark return on equity of approximately 8.75% for 2008-2009. The indicated benchmark return on equity of 8.75% would be applicable to Yukon Electrical at a common equity ratio of 52.5%.

However, the benchmark ROE is viewed as below the level consistent with a fair and reasonable return. Thus, requiring shareholders to commit additional equity to achieve a 52.5% equity ratio to have the opportunity to earn a benchmark equity return regarded as too low is fundamentally incongruous. As a result, I recommend that the actual common equity ratio of Yukon Electrical be raised to 47.5% and to allow an incremental equity risk premium of 0.50% above the benchmark return on equity. The 0.50% incremental equity risk premium compensates for the difference in financial risk between the proposed 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a common equity ratio of 47.5%, the allowed ROE for Yukon Electrical should be set at 9.25%.

II. ANALYTICAL FRAMEWORK

A. RELATIONSHIP BETWEEN COST OF CAPITAL AND CAPITAL STRUCTURE

The cost of capital is largely a function of business risk, that is, the risks arising from the operations/assets of a firm. The cost of capital, however, is also a function of financial risk, i.e., additional risk borne by the common equity shareholder because the firm is using fixed obligation securities (e.g., long-term debt) to finance a portion of its assets. Therefore, the capital structure, comprised of fixed obligation securities and common equity, can be viewed as a summary measure of the financial risk of the firm.

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. Since the issuance of debt carries fixed costs which must be paid before the equity shareholder receives any return, the addition of debt to the capital structure increases the potential variability of the equity shareholder's return. Thus, as the debt ratio rises, the cost of equity rises. In the absence of the deductibility of interest expense for tax purposes and costs associated with the use of excessive debt, the increase in the cost of equity offsets the increase in the debt ratio, so the overall cost of capital to a firm would not change materially if the firm were to change its capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used.

However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partially offsetting the tax advantage. In addition, although interest expense is tax deductible at the corporate level, it is taxable to investors at a higher rate than equity, offsetting some of the net after-tax advantage of increasing the debt component of the capital structure. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest flow through to customers.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will accompany an increase in the cost of equity.

B. APPROACHES TO DETERMINING THE FAIR RETURN

Recognizing the relationship between the cost of capital and capital structure, there are effectively two approaches that can be used to determine the fair return. The first is to assess the specific regulated company's business risks then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity.

The second approach entails acceptance of the specific regulated company's actual capital structure for regulatory purposes, or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (business and financial) risk of the regulated company to those of the proxies or benchmark. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is compared to that faced by the proxy companies used to estimate the equity return requirement. If the total risk of the proxy companies is higher or lower than that of the specific regulated company utility, an

adjustment to the proxies' cost of equity would be required when setting the specific regulated company's allowed return on equity.

The National Energy Board (NEB) employed the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single benchmark return on equity could be applied across all of the pipelines.[2] It is also the approach that was adopted by the EUB in its Generic Cost of Capital Decision. In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the NEB/EUB approach as long as the combination of actual/allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. The British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. However, it explicitly designates a low risk benchmark utility (Terasen Gas) and a low risk benchmark return on equity. The combination of capital structures and equity risk premiums has also been used in Ontario and Québec.

For purposes of this proceeding, I have utilized the first approach and estimated the capital structure that is intended to fully reflect the business risks of Yukon Electrical. In other words, I have estimated a capital structure for Yukon Electrical, based on the principles set out in Section III that would be compatible with the application of a benchmark return on equity to Yukon Electrical. If, however, the common equity ratio

[2] In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002, 36% in 2005 and 40% in 2007.

adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

C. BENCHMARK RETURN ON EQUITY

1. Conceptual Considerations

Both approaches to determining a fair return outlined in Section II.B rely on the measurement of the equity return that would be applicable to a benchmark utility or average risk Canadian utility. That return will be referred to as a benchmark return on equity. A capital structure for Yukon Electrical would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return on equity; and (c) would equate the level of total (business and financial) risk faced by Yukon Electrical to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the common equity ratio for Yukon Electrical is established so that no adjustment to the benchmark return on equity is required.[3]

The term benchmark utility is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the benchmark utility reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve a particular debt rating,

[3] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." (Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999)

typically an A rating. The typical, average risk Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's (S&P).

Designation of a debt rating as an indicator of relative risk recognizes that (a) debt ratings reflect both business and financial risk, and (b) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category.

The applicability of the benchmark return on equity to a specific utility thus is dependent on the business risks and capital structure allowed for that utility. Since different utilities face different levels of business risk, utilities with lower (higher) business risk would require lower (higher) common equity ratios. If the lower (higher) business risk of specific utilities is completely compensated for through a lower (higher) common equity ratio, their total (or investment) risk will be approximately the same. If the allowed common equity ratio is sufficient to result in a level of total risk equivalent to the benchmark, the benchmark return on equity can be directly applied to that utility, with no adjustment to the level of the benchmark return on equity.

For specific purposes of this proceeding, I recommend adopting as the benchmark return on equity, the generic return on equity applicable to the Alberta utilities as adjusted for any forecast changes in interest rates. The return on equity adopted by the EUB for 2008 was 8.75%, based on a forecast long-term Canada bond yield of 4.55%.[4]

2. Benchmark Return on Equity for Test Years 2008-2009

Expert testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Preparation of testimony, responses to information requests and cross-examination of witnesses entail a considerable amount of money, time and effort. As a result, the cost impact on a utility the size of Yukon Electrical can be

[4] Order 2007-0347, November 30, 2007.

significant. Yukon Electrical is proposing that for the specific purposes of this proceeding, the Alberta generic return on equity be used as a point of departure for establishing its allowed return on equity for the 2008-2009 test years, as adjusted for changes in interest rates. The generic return on equity established by the EUB in Decision 2004-052 and adjusted automatically each year in subsequent Orders is virtually identical to "benchmark" ROEs adopted by other Canadian regulators, including the National Energy Board and, implicitly, by the Public Utilities Board of the Northwest Territories when it established the allowed ROE for Northwest Territories Power Corporation in Decision 13-2007 (August 29, 2007). Using the EUB's generic return on equity as a point of departure, the costs associated with the determination of the allowed return on equity for Yukon Electrical should be greatly reduced. The cost of capital testimony can then focus on the issue of the capital structure that is required to fully compensate for the utility's business risks and, if necessary, given the specific financing considerations of the utility, any incremental equity risk premium relative to the benchmark return on equity that is required.

Given these considerations, I accept, for the express purposes of this proceeding, that the return on equity determined by the EUB in Decision 2004-052, as adjusted for changes in interest rates since the decision was issued, will be used as the basis for establishing the allowed return on equity for Yukon Electrical.[5] That return on equity, however, can only be applied to a common equity ratio that fully compensates for Yukon Electrical's business risks.

Decision 2004-052 established an automatic adjustment mechanism for determining a utility's allowed return on equity in response to a change in interest rates. Automatic adjustment mechanisms for determining a utility's allowed return on equity are relied

[5] In my opinion, as well as that of Yukon Electrical, the EUB benchmark return on equity is below the level commensurate with the comparable returns standard. The EUB as well as the NEB have initiated proceedings to determine whether their automatic adjustment mechanisms continue to produce a fair return. In the ATCO Utilities' view (with which I concur), as filed with the AUC on April 4, 2008, the automatic adjustment mechanism does not produce a fair return. Nevertheless, until such time as the issue has been reviewed by the AUC, Yukon Electrical is prepared to accept the EUB "benchmark" as a point of departure for establishing its allowed ROE for 2008 and 2009.

upon in six regulatory jurisdictions in Canada. The various mechanisms are all quite similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a base, or initial, return on equity and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base allowed return on equity are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula, or adjustment factor, to be used to adjust the allowed return on equity from one year to the next. The forecast yield on the long-term Government of Canada bond is used as the proxy for the risk-free rate.

Application of an adjustment mechanism like those used in most Canadian jurisdictions requires the following steps:

Step 1: Establish the forecast long-term Canada bond yield for the test year(s),

Step 2: Apply the adjustment factor to the difference between the test year forecast(s) of the long-term Canada bond yield and the bond yield underlying the base allowed return on equity, and

Step 3: Adjust the base allowed return on equity by the amount(s) determined in Step 2.

In five of the six Canadian jurisdictions that currently use an automatic adjustment mechanism,[6] the adjustment factor is set at 0.75, i.e., the change in allowed return on equity equals 75% of the change in the forecast long-term Government of Canada bond yield. The 75 basis point change in allowed return on equity for every one percentage point in the forecast long term Government of Canada bond yield reflects some

[6] The five regulatory boards that use automatic adjustment mechanisms with a 0.75 adjustment factor are the EUB, the British Columbia Utilities Commission, the Ontario Energy Board, the National Energy Board, and the Régie de l'Energie de Québec. In Newfoundland and Labrador, the adjustment factor is 0.80.

recognition that the return on equity does not move in tandem (one for one) with changes in the yield on long-term government bonds.[7]

As indicated in Section II.C.1 above, the 2008 Alberta generic return on equity is 8.75% (at a long-term Canada bond yield of 4.55%). Yukon Electrical is proposing rates for a two-year test period, 2008-2009. I recommend that the PUB adopt a single benchmark return on equity for both test years, based on the average forecast long-term Government of Canada bond yield during the test years.

The most recent Consensus Economics, *Consensus Forecasts* (April 2008) indicates that the 10-year Government of Canada bond yield will be 3.6% in July 2008 and 3.9% by April 2009. During the first four months of 2008, the 10-year Government of Canada bond yield averaged approximately 3.7% (and the 30-year Government of Canada bond yield averaged 4.1%). Based on the actual yields to date and the *Consensus* for July 2008 and April 2009, the 10-year Government of Canada bond yield is forecast at approximately 3.7%. During April 2008, the spread between 10 and 30 year Canada bond yields averaged approximately 50 basis points. The addition of 50 basis points to the forecast 10-year bond yield produces a forecast 30-year Canada bond yield of 4.2% for 2008.

There is no consensus forecast for all of 2009. However, the long-term forecast for 10-year Government of Canada bond yields contained in the April 2008 Consensus Economics, *Consensus Forecasts* anticipates that the 10-year Government of Canada bond yield will be 5.0% in 2010. In the absence of a 2009 consensus forecast for Canada, the quarterly consensus forecasts for U.S. 10-year Treasury bond yields can be used to approximate the forecast for the 10-year Government of Canada bond yield, as the available consensus forecasts show that the Canadian and U.S. rates are expected to track

[7] While the 0.75 adjustment factor recognizes to some extent the inverse relationship between equity risk premiums and equity returns, it overstates the extent to which they move together. Nevertheless, to the extent that the automatic adjustment formula has reduced allowed ROEs since the inception of such formulas, it is reasonable for the formula to increase allowed ROEs by a similar amount until such time as a benchmark return is recalibrated and, if warranted, a new formula established.

closely, with the 10-year Canada bond slightly higher (10 basis points) than the 10-year Treasury by 2010. The Blue Chip *Financial Forecasts* (May 1, 2008) anticipates that the 10-year U.S. Treasury yield will increase quarterly by 0.10% during 2009. The resulting 10-year 2009 Government of Canada bond yield would be approximately 4.2%. Based on these forecasts and a continuation of the current 50 basis point spread between 10- and 30-year Canada bond yields, I anticipate that the 30-year Canada bond yield will average 4.7% in 2009.

The average forecast 30-year yield for the two test years is thus approximately 4.5%, similar to the 4.55% forecast relied on by the EUB to set the Alberta "benchmark" return of 8.75%. While the 2008-2009 average forecast long-term Canada bond yield of 4.5% is somewhat higher than the forecast for 2008 alone, Yukon Electrical is taking the risk that the actual long-term yields in 2009 will be higher than currently anticipated.

Based on a 4.5% long-term Canada bond yield forecast, the benchmark return on equity (ROE) for Yukon Electrical's 2008-2009 test years is approximately 8.75%, the same as the 2008 Alberta generic return on equity.

I recommend, therefore, that a benchmark return on equity of 8.75% be adopted for both test years; the 8.75% would be applicable to the common equity ratio estimated in Sections III to VIII. If, however, the common equity ratio adopted for ratemaking purposes is lower than that which would fully compensate for Yukon Electrical's business risks, then an upward adjustment will need to be made to the benchmark ROE for Yukon Electrical's higher financial risks.

III. PRINCIPLES FOR CAPITAL STRUCTURE

The following principles should be respected when establishing the appropriate capital structure for Yukon Electrical:

A. The Stand-Alone Principle.
B. Compatibility of Capital Structure with Business Risks.
C. Maintenance of Creditworthiness/Financial Integrity.

Each of these principles is defined below.

A. THE STAND-ALONE PRINCIPLE

The stand-alone principle encompasses the notion that the cost of capital incurred by Yukon Electrical should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm.

Yukon Electrical is 100% owned by ATCO Electric. ATCO Electric, in turn, is a wholly-owned subsidiary of CU Inc. Yukon Electrical operates as a stand-alone entity (separate from the other electric utility operations of ATCO Electric). CU Inc. raises debt on behalf of Yukon Electrical. CU Inc.'s debt is rated A(high) by DBRS and A by S&P. Debt raised by CU Inc. is mirrored down to the individual ATCO Utilities, including Yukon Electrical, at the cost incurred by CU Inc. Yukon Electrical's customers, therefore, receive the benefits of CU Inc.'s ratings. In turn, Yukon Electrical should contribute its fair share toward the maintenance of the debt ratings through its own capital structure and return on equity. It would be inequitable for customers to receive the

benefits of debt costs that reflect an A(high)/A debt rating while the common equity ratio (or equity thickness) is only adequate, for example, for a (notional) BBB rating.

Based on the indicated spreads for new issues as published by RBC Capital Markets, CU Inc. has been able to raise new 30-year debt on average at approximately 120 basis points over a similar term Government of Canada bond during 2007 and the first quarter of 2008. Over this period, spreads for utilities with one debt rating in the BBB category (split-rated utilities) have ranged from 135 basis points (Union Gas rated A by DBRS and BBB+ by S&P) to 175 basis points (EPCOR Utilities, rated A(low) by DBRS and BBB+ by S&P) and have averaged approximately 140-145 basis points (See Schedule 1).

The 2007-2008Q1 average masks the widening spreads over the period. As investors have become more risk-averse, and the outlook for the economy has deteriorated, credit spreads have widened considerably since the end of 2006. At the end of March 2008, the indicated spread for a new 30-year CU Inc. issue was 157 basis points versus 92 basis points at the end of 2006. Spreads for new split-rated A/BBB issues have increased from approximately 125-130 basis points to 200 basis points over the same period.

Depending on the state of the capital markets, the spread between the cost of a new long-term debt issue for a strong A credit and one for a split A/BBB credit can be much higher than it is currently. As recently as five years ago, the spread has been as high as 100 basis points.

With respect to electric power corporations that are still investment grade but rated in the BBB category by all the debt rating agencies, there is only one conventional equity corporation (i.e., non-income trust) included in the S&P/TSX Utilities Sector, TransAlta Corporation. The average indicated spread for a new 30-year TransAlta Corporation debt issue during 2007-2008Q1 has been 278 basis points; at the end of March 2008, the spread was 390 basis points. (Schedule 1) The recent differential between the TransAlta Corporation cost of long-term debt and the CU Inc. cost of long term debt of approximately 233 basis points provides a perspective on the potential magnitude of the

benefits to ratepayers of Yukon Electrical's affiliation with CU Inc. As a true stand-alone entity, Yukon Electrical would not be able to obtain investment grade debt ratings given its small size. The estimation of an appropriate capital structure for Yukon Electrical should recognize the magnitude of the cost benefits conferred upon ratepayers arising from Yukon Electrical's ability to access debt capital through CU Inc. rather than on its own.

B. COMPATIBILITY OF CAPITAL STRUCTURE WITH BUSINESS RISKS

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework that can lead to the failure to recover a compensatory return on, and/or the return of, the capital investment itself.

C. MAINTENANCE OF CREDITWORTHINESS/FINANCIAL INTEGRITY

For larger utilities like CU Inc. which regularly access the public debt markets, a reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. An A debt rating assures that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult or weak capital market conditions.

As noted above, Yukon Electrical is too small to have its own debt ratings (i.e., it would not be investment grade) or to access the public debt markets on its own. If it were to access third-party debt on its own, its options would be limited to banks or insurance companies at a significantly higher cost than is available to CU Inc., and with more stringent covenants. A rigid application of the stand-alone and creditworthiness/financial integrity principles would impute to Yukon Electrical both the actual cost of debt that Yukon Electrical would be able to obtain on its own and the capital structure that would

be required by a potential lender to provide debt capital in the absence of its affiliation with CU Inc.

To my knowledge, the only small (total capital less than $100 million) regulated company that has accessed debt on a true stand-alone basis within the past five years is Natural Resource Gas (NRG), a small Ontario natural gas distributor. NRG was able to obtain five-year bank financing during 2005, a period of easy credit, at a spread over five-year Government of Canada bond yields of approximately 280 basis points. At the same time, the larger gas utilities (with debt ratings in the A/BBB rating categories) were able to issue five-year debt at spreads of 40-45 basis points over five-year Government of Canada bond yields. At the time, TransAlta Corporation was able to raise five-year debt at approximately 70 basis points above a similar term Government of Canada bond yield. While NRG is somewhat smaller (assets of approximately $9 million) than Yukon Electrical, it would be of reasonably similar business risk to Yukon Electrical. Thus NRG's stand-alone cost of debt provides a further indicator of the order of magnitude of the benefit that Yukon Electrical's ratepayers receive as a result of Yukon Electrical's affiliation with CU Inc.

My assessment of the appropriate capital structure for Yukon Electrical balances the stand-alone and creditworthiness and financial integrity principles with a recognition that the impact of small size on lenders' willingness to lend funds and on the stand-alone cost of debt would be, in part, related to the lack of liquidity and institutional interest in small debt issues rather than to fundamental business risk factors. Nevertheless, the appropriate capital structure and return on rate base for Yukon Electrical needs to recognize the cost benefits that Yukon Electrical's ratepayers receive.

IV. BUSINESS RISK

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short-term and long-term risks. Long-term risks are important because utility assets are long-lived. Moreover, utility stocks are not typically purchased as short-term investments. Since utilities are generally regulated on the basis of annual revenue requirements, there is a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall higher return rewards when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future.

Business risk encompasses those market demand, supply and regulatory factors that expose the shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment.

Market demand risk relates to those factors that can lead to annual volatility in electricity sales or loss of customers. It includes market size, economic diversity and strength of the service area, growth potential, concentration of sales, competition with alternative energy sources and weather.

Supply and physical (operating) risks faced by an integrated electric utility comprise the risk of under-earning due to the inability to deliver electricity, or the inability to recover costs associated with the acquisition or delivery of electricity. The physical risks of the utility are a function of its geography, mix of generation and ability to access alternative sources of supply.

The regulatory framework in which a utility operates is, next to the basic demand risks, the most significant aspect of risk to which shareholders in a regulated firm are exposed.

The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

Yukon Electrical is a small integrated electric utility serving 19 communities and approximately 15,000 customers spread throughout the territory. Whitehorse, the largest community, accounts for over 70% of the population of the Yukon. T he largest community served outside of Whitehorse is Watson Lake, with a population of approximately 1,600. T he populations of the other communities served range from approximately 10 to 300. Total sales in 2007 were approximately 300 GW.h. To put this in perspective, the following table compares customers, sales, and rate base of major Canadian investor-owned and government-owned electric utilities with rated debt, i.e., not guaranteed.[8]

Table 1

Company	Customers	Sales (GW.h.)	Rate Base ($ Millions)
Yukon Electrical	15,000	300	43
Electric Utilities with Rated Debt:			
ATCO Electric	216,000	10,300	1,500
EPCOR Utilities	318,000	7,100	500
FortisAlberta	430,000	14,700	800
FortisBC	152,000[1/]	3,100	680
Hydro One	1,300,000	29,300	8,400
Hydro Ottawa	280,000	7,500	500
Maritime Electric	66,000	1,000	200
Newfoundland Power	229,500	5,000	750
Nova Scotia Power	460,000	11,600	2,900

[8] For comparison with other northern electric utilities:

Company	Customers	Sales (MW.h.)	Rate Base ($ Millions)
NTPC[1/]	18,800	310,000	200
NU (YK)	7,900	157,000	20
NU (NWT)	2,600	35,000	12
YEC[1/ 2/]	15,000	302,000	158

[1/] Includes both direct and indirect customers.
[2/] Rate base approximated by 2006 net property, plant and equipment.

[1/] Includes both direct (approximately 100,000) and indirect customers.

As the table above indicates, Yukon Electrical is approximately one-quarter the size of the smallest utility (Maritime Electric) with its own debt ratings. Growth in rate base has been relatively strong over the past 10 years (approximately 3% annually). Future growth is expected to come from growth in new residential and commercial development and the continuing replacement of aerial infrastructure, i.e., exposed distribution lines, with underground lines. While rate base growth is expected to remain relatively strong, Yukon Electrical is expected to remain a very small utility relative to its Canadian peers. From a business risk fundamentals perspective, small size limits a utility's ability to diversify its risks geographically, operationally and among services provided.

Yukon Electrical's customer profile, based on 2007 actual data, is as follows:

Table 2

	Residential	**Commercial and Secondary[1/]**	**Street & Sentinel Lighting**	**Wholesale**
Sales ($000)	$14,088	$20,182	$837	$53
Customers	12,452	2,592	na	1

[1/] The majority of customers (2,570) and sales ($18,728) are commercial.

While Yukon Electrical currently has no industrial customers of its own, the economic base of the Yukon will have secondary impacts on the residential and commercial customer load. The cornerstones of the economy of the Yukon have historically been resource-based industries. The impact of these industries (principally mining) on the economy of the Yukon declined over the past decade following the closure of the Faro Mine in January 1997.[9] Prior to the mine's closure, the mining and oil and gas extraction industries had accounted for approximately 12% of GDP. In 2006, the portion of GDP accounted for the mining/oil and gas industries had fallen by half, to approximately 6%

[9] The mine was operated by Anvil Range Mining at the time of its closure.

(virtually all of which is accounted for by gold mining). The opening of the new Minto Mine in late 2007[10] is expected to have a positive impact on the economy, but will correspondingly increase the potential volatility in the economic performance of the Yukon.

The largest sector of the Yukon economy is public administration (government) contributing approximately 24% of GDP in 2006. This sector has a moderating impact on the territory's economy, because its rate of growth, while exhibiting some variability, is not subject to the wide swings seen in some other sectors, e.g. the resource-based sectors, manufacturing and construction. The importance of government to the economy of the Yukon is reflected in Yukon Electrical's customer profile/sales margin. Of Yukon Electrical's 18 largest customers, 11 are government-related entities, accounting for 17% of gross margin. Despite the moderating effect of government, annual GDP growth rates in the Yukon have been volatile, in part due to the year to year changes in construction activity. Over the 1998-2006 periods, annual GDP growth in the Yukon has been approximately twice as volatile as that of the individual provinces.

The divergent rates of growth in the Yukon over time demonstrate the volatility in the economy and potential impact on Yukon Electrical. Not only do the actual annual rates of growth exhibit considerable volatility, there can be significant differences between rates of growth as initially reported or forecast and the final actual rates of growth once all revisions have been made. For example, in May 2007, the Yukon Government, in its *Yukon Economic Overview and Outlook 2007* reported a 2005 rate of real GDP growth of 5.2%. The actual rate, as indicated above, was only 3.9% when revised in November 2007. The potential variance between forecast and actual rates of growth enhances Yukon Electrical's forecasting risk. On the cost side, forecasting risks are further increased by the tight labour market, particularly for skilled workers, rising wages and rising costs of basic materials.

[10] The mine is expected to connect to Yukon Energy in late 2008 and generate approximately 40 MW.h of sales. The costs associated with extending the transmission line to the mine are being paid by Minto Explorations Inc., the mine operator, and the Territorial Government.

Electric utilities, including Yukon Electrical, are subject to the risk of lost sales arising from the increasing emphasis on energy efficiency, conservation and reducing peak load. Lost load due to energy efficiency and conservation efforts reduces the utility's earnings. The implementation of energy conservation and efficiency initiatives, with the objective of reducing energy costs and environmental impacts raises the risk to earnings.[11] The Yukon Government is actively promoting energy efficiency through its Energy Solutions Center. Moreover, the elimination of Yukon Energy's Rate Stabilization Fund will act as an incentive for conservation.

With respect to supply and physical risks, Yukon Electrical faces a significantly higher level of risk relative to other Canadian electrical utilities. The electric utility network in the Yukon has two main grids: t he Whitehorse/Aishihik/Faro (WAF)[12] and the Mayo/Dawson grid.[13] The WAF grid is fed by Yukon Electrical's Fish Lake hydroelectric facility and Yukon Energy's Aishihik and Whitehorse hydroelectric plants. Yukon Electrical has backup generation to the WAF grid through its diesel standby plants at Carmacks, Ross River, Haines Junction/Canyon Creek and Teslin. Yukon Electrical's diesel plant at Stewart provides backup generation capacity to the Mayo/Dawson Grid. Yukon Electrical also serves a number of isolated communities (not connected to the grid) in the Yukon with diesel generation (Watson Lake, Beaver Creek, Destruction Bay/Burwash Landing, Old Crow, Pelly Crossing and Swift River). P elly Crossing is forecast to be connected to the WAF grid in the 4th quarter of 2008.

Approximately 12% of Yukon Electrical's rate base is comprised of generation assets (approximately 90% of which is diesel). The presence of generation assets in rate base generally increases the business risk of Yukon Electrical relative to a pure distribution utility, as the operational risks associated with generation exceed those of "wires"

[11] A number of regulatory jurisdictions in North America have implemented or are investigating revenue decoupling (decoupling revenues from consumption) to address this issue.
[12] The WAF grid connects Whitehorse with Yukon Electrical's franchise communities of Carcross, Carmacks, Haines Junction/Canyon Creek, Ross River and Teslin.
[13] The Mayo/Dawson grid connects Yukon Electrical's franchise communities of Stewart Crossing and Keno Hill with Yukon Energy's franchise communities of Dawson City, Elsa and Mayo.

554 operations. In the case of Yukon Electrical, the operating risks are exacerbated by the
555 severe climate in which the utility operates, increasing both the risk of outages and the
556 potential unanticipated impacts of repair (in terms of both time and expenditures), and the
557 isolated nature of some of the smaller communities served. While Yukon Electrical has
558 proposed deferral accounts that cover diesel fuel costs, the high cost of diesel fuel creates
559 an additional incentive to conserve energy (thus leading to lower than expected sales).
560 Further, in contrast to hydroelectric generation, diesel generation is exposed to greater
561 risks of complying with increasingly stringent environmental standards. Yukon
562 Electrical has a significant amount aerial infrastructure, i.e., exposed distribution line.
563 Although the exposed lines are being moved underground, the exposed lines, in
564 conjunction with a heavily treed service territory, increases the operating risks of Yukon
565 Electrical.
566
567 With respect to regulatory risk, as independent tribunals, regulators have the power to
568 expose utilities to relatively high risks, by, for example, disallowing costs, approving rate
569 designs that are tilted against recovery of fixed costs, or returns that do not conform to
570 informed investors' perception of risk. Alternatively, regulation can provide an
571 environment characterized by even-handedness, conducive to continued growth
572 consistent with economic allocation of resources, and affording the utility an opportunity
573 to achieve a fair return with a reasonably high probability. This explains why regulation
574 is considered to be a key element of a utility's business risk profile. On balance, the
575 regulatory environment in the Yukon has been even-handed and reasonable in its
576 approach; the Board has granted deferral accounts for costs that are beyond the control of
577 management, including power costs, diesel fuel and generation costs, plant maintenance
578 expense and rate case expense.[14] Nevertheless regulatory decisions can also have a
579 negative impact on utilities.
580
581 Ms. McShane has no reason to conclude that, based on current policies and practice, that
582 Yukon Electrical, similar to other regulated utilities in North America, will not be

[14] The existence of these deferral accounts does not constitute a guarantee that the costs accrued in the account will be recoverable from customers.

provided a reasonable opportunity to recover its capital investment. Nevertheless, the regulator cannot provide a guarantee that the capital investment will be recovered. The regulator can not provide a guarantee that long-term economic conditions will permit the full recovery of the invested capital, it does not make energy policies that can favor the government-owned utility and/or impact on the ability to recover the invested capital, and it cannot bind the decisions of future regulators.

On balance, as a very small utility operating in a service territory with an undiversified economic base and facing significant geographic physical/operating challenges, Yukon Electrical:

- is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada,
- is of higher than average business risk within the spectrum of Canadian utilities and,
- is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited.

V. CAPITAL STRUCTURES OF PEERS

The determination of the capital structure that reflects Yukon Electrical's business risks and would be compatible with the application of the benchmark return on equity requires comparisons with the capital structures of other electric utilities for two reasons. First, electric utilities which raise debt in the public markets (and, therefore, have debt ratings) have capital structures that have been "tested" by the capital markets. Thus, their capital structures, in conjunction with other key financial metrics (e.g., coverage ratios), provide an indication of the capital structure required to maintain investment grade debt ratings. Second, the common equity ratios allowed for other electric utilities (whether or not their debt is rated), either through regulatory decisions or settlements, provide a measure of the

level that is warranted for an electric utility to compete for capital with its peers, with due regard to differences in business risk.

Table 3 below sets out the average actual common equity ratios of Canadian electric utilities with rated debt, as well as those of low risk U.S. electric utilities with debt rated in the A category.

Table 3

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	43.4%
Transmission & Distribution	A/Baa1/A-	44.5%
Integrated	A(low)/Baa2/BBB+	40.5%
U.S. A-rated Electric Utilities	na/A2/A	49.0%

Source: Schedules 2, 3 and 4.

Table 3 indicates that the average actual common equity ratios for all Canadian electric utilities with rated debt and for Canadian transmission and distribution utilities have averaged close to 43.5% and just below 45% respectively. The corresponding debt ratings by all three debt rating agencies have been, on average, approximately A-/A(low).

Given Yukon Electrical's higher than average business risks, the equity ratios maintained by other Canadian electric utilities indicate that a 45% common equity ratio would be too low to fully compensate for its business risks. Two of the smaller investor-owned primarily electric distribution utilities that would be considered the closest comparators to Yukon Electrical of the Canadian electric utilities with rated debt (Maritime Electric and Newfoundland Power) both have target actual common equity ratios of 45%. While they are the closest comparators, both are significantly larger and face lower business risk than Yukon Electrical. Moreover, their allowed returns on common equity are higher than the returns allowed under the Alberta formula which serves as the benchmark return on

equity for Yukon Electrical.[15] These specific "comparators" strengthen the conclusion that a 45% common equity ratio for Yukon Electrical (at the benchmark return on equity) is too low to fully compensate for Yukon Electrical's business risks. With respect to the recent Northwest Territories Power Corp. (NTPC) decision, for the 2007/08 test year, the Public Utilities Board of the Northwest Territories adopted a common equity ratio of 48.86% and an incremental equity risk premium of 0.50% for NTPC, a higher business risk utility than Yukon Electrical. The corresponding equity ratio for NTPC that would fully compensate for its higher business risks would be approximately 56-57%. Since NTPC faces higher business risk than Yukon Electrical, the fully compensatory equity ratio for Yukon Electrical indicated by the NTPC decision would be lower than 56-57%.

As the capital market has become increasingly global, Canadian utilities increasingly find themselves competing with foreign utilities for financing. The similarities and proximity of the U.S. and Canadian capital markets make comparisons with U.S. electric utilities especially relevant. The major bond rating agencies increasingly draw comparisons between Canadian utilities and their U.S. peers. Thus, the capital structures of U.S. electric utilities of reasonably similar business risk to Yukon Electrical and with debt rated in the A category may provide some guidance.

Since 1999, S&P has assigned to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest.[16] As of November 2007, the median business profile score of the U.S. electric utilities with debt rated in the A category was "4".[17] By comparison the average S&P business profile score assigned to Canadian utilities has been "3". Like Yukon Electrical, the majority of these

[15] Maritime Electric, which is not subject to an automatic adjustment formula, was allowed a common equity return of 10.0% for the 2008 test year, approximately 125 basis points higher than the EUB's generic return on equity for the same test year. Newfoundland Power's allowed return on equity at a 4.55% long-term Government of Canada bond yield would be 8.91%.

[16] The key qualitative factors that S&P evaluates in assessing the business risk of regulated electric utilities include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness.

[17] In November 2007, S&P integrated its utility business/financial risk evaluation methodology into its broader corporate ratings matrix and no longer provides as detailed or transparent a matrix for utilities.

companies are largely "wires" or "pipes" companies.[18] However, as discussed in Section IV, Yukon Electrical would be viewed as facing higher business risks than the typical Canadian utility. On balance, based on its business risk fundamentals, Yukon Electrical would, on a stand-alone basis, be assigned a business profile score within the "4" category, higher than the typical Canadian utility, but the same as the A rated U.S. utilities.

The higher business risk of the U.S. electric utilities relative to the typical Canadian electric utility is reflected in their higher common equity ratios, leading to similar debt ratings. As indicated in Table 3 above, the median 2006 actual common equity ratio of U.S. electric utilities with debt rated in the A category was 49.0%. Given the similarity in the level of business risks between the A rated U.S. electric utilities and Yukon Electrical, in isolation,[19] the 49% median equity ratio is a reasonable benchmark for Yukon Electrical.

With respect to allowed common equity ratios, Table 4 below summarizes the most recently adopted capital structures for major Canadian electric utilities, along with any applicable incremental equity risk premiums. Unlike Yukon Electrical, both NTPC and Yukon Energy are government-owned utilities whose debt is guaranteed by their respective Territorial governments. However, like Yukon Electrical, they are both northern utilities, and they are both largely treated like investor-owned utilities for purposes of establishing capital structure and return on equity.

[18] Newfoundland Power, for example, was assigned a business risk profile score of "3". Newfoundland Power would be considered to face lower business risks than Yukon Electrical, given its size, service area and more comprehensive slate of deferral accounts, including revenue protection against weather variations.

[19] As discussed in more detail in Section VII, the debt ratings of utilities in a particular business risk category are not solely driven by capital structures. They are also driven by other financial parameters, including coverage ratios. Coverage ratios are a function of cash flows, which, in turn, are dependent upon equity returns. The common equity return for the A rated U.S. electric utilities has averaged 11.8% over the past three years (2004-2006), compared to the 8.75% benchmark return. Taking the actual common equity ratios and ROEs of the A rated utilities together, a 50% common equity ratio for Yukon Electrical at the benchmark 8.75% ROE would be too low to equate Yukon Electrical to a benchmark utility.

Table 4

Alberta Taxable Distributors	37.0%
FortisBC	40.0% (plus 0.40% risk premium above BCUC's low risk utility benchmark)
Maritime Electric	42.7% (ROE has been approximately 1.25% higher than Canadian average)
Newfoundland Power	44.5% (risk premium 0.15% higher than benchmark)
Northwest Territories Power	48.6% (plus 0.50% risk premium)
Nova Scotia Power	37.5% (ROE approximately 0.75% higher than Canadian average)
Ontario Electric Distributors	40.0%
Yukon Energy	40.0% (plus 0.52% risk premium above BCUC's low risk utility benchmark) [1/]

[1/] Equal to average of the incremental equity risk premiums of Pacific Northern Gas (65 basis points) and FortisBC (40 basis points); by Order in Council, Yukon Energy's return on equity is then reduced from the "fair return on common equity" by 0.50%.

Source: Schedule 5.

If the capital structure for each of the utilities in Table 4 above were adjusted to eliminate the incremental equity risk premiums, the allowed equity ratios would be approximately 46-47%. On average the companies included in Table 4 are of lower business risk than Yukon Electrical. On this basis, the common equity ratio for Yukon Electrical necessary to compensate for its business risks would be higher than 46-47%.

With respect to U.S. electric utilities, since the beginning of 2005, the average common equity ratio adopted for ratemaking purposes has been 47.9%.[20] The average business profile score of all U.S. electric utilities rated by S&P is "5". Thus, the business risk of the U.S. electric utility industry as a whole is higher than that of Yukon Electrical. However, the average debt rating of all U.S. electric utilities is only BBB. Consequently, it may be inferred that a common equity ratio of 47.5% is not adequate for a "5" business profile score and an A credit rating. Given Yukon Electrical's lower fundamental business risks than the U.S. industry in the aggregate, but higher target debt rating (in the A category), the U.S. electric industry average allowed common equity ratio suggests that

[20] Regulatory Research Associates, *Major Rate Case Decisions, January–March 2008*, April 2, 2008. Allowed returns on equity have averaged 10.4% over the same period.

a 47.5% common equity ratio would constitute a floor for the equity ratio required to equate Yukon Electrical to the benchmark utility.

On balance, the actual and allowed equity ratios of other Canadian electric utilities, and those of U.S. electric utilities (in conjunction with their actual and allowed ROEs) indicate that the common equity ratio required to fully compensate for Yukon Electrical's business risks would be no less than 47.5%.

VI. RATING AGENCY DEBT RATIO GUIDELINES

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), S&P has published the most detailed matrix of quantitative guidelines for different debt ratings.[21] For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds From Operations (FFO)[22] Interest Coverage, and FFO to Total Debt (discussed in Section VII). S&P does not apply their guidelines mechanistically; however, the guidelines do represent one objective basis for evaluating an appropriate stand-alone capital structure for Yukon Electrical.

S&P's debt ratio guidelines for an A debt rating and a business risk score of "4", the notional business risk score attributed to Yukon Electrical, are as follows:

Table 5

Total Debt/Total Capital	45.0-52.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

The guidelines for a business risk profile score of "4" indicate that a common equity ratio in the range of 48% to 55% (mid-range of 50.0-52.0%) is warranted for an A rating.

[21] DBRS has published guidelines, but the guidelines have not distinguished by either business risk or investment grade rating category.
[22] FFO means Funds from Operations, which equal net income plus non-cash items, including depreciation, deferred taxes and other non-cash expenses, e.g., amortization of regulatory assets.

Moody's also has published quantitative guidelines. As with S&P, other factors may outweigh the mechanistic application of the guidelines in determining a rating. However, the guidelines provide "broad guidance on the ratio ranges that may generally be seen at different rating levels".[23] While neither Yukon Electrical nor CU Inc. has a Moody's rating, there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's. Thus Moody's guidelines are applicable to those companies and, in turn, will play a role in the formation of target capital structures among Canadian utilities, with the objective of maintaining investment grade debt ratios.

Canadian distribution utilities are typically considered to be operating in a "low business risk" environment by Moody's due to the high degree of regulation and a supportive regulatory system. However, due to its specific business risk fundamentals and small size, Yukon Electrical would likely be classified within the "medium business risk" category. Moody's debt ratio guidelines for an A rating for a regulated company of "medium risk" are:

Table 6

Debt/Capital	40.0-60.0%

Source: Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

Based on Moody's debt ratio guidelines, a reasonable common equity ratio for Yukon Electrical compatible with a stand-alone A rating would be in the middle of the range, i.e., approximately 45%-55%.

The S&P and Moody's debt ratio guidelines, taken together, support a common equity ratio of approximately 45%-55% (mid-point of 50%).

[23] Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005, page 8.

VII. RATING AGENCY GUIDELINES OTHER THAN DEBT RATIO

Based on the actual and allowed equity ratios for other Canadian and low risk U.S. electric utilities (Section V), the rating agency debt ratio guidelines (Section VI) and consideration of Yukon Electrical's relative business risk (Section IV), a common equity ratio range of 47.5%-52.5% (mid-point of 50%) would be required to equate Yukon Electrical to the benchmark utility (i.e., one with a credit rating of A).

However, the common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Both S&P and Moody's consider cash flow coverage ratios to be key quantitative financial metrics, specifically FFO Interest Coverage and FFO/Total Debt. If a utility is able to achieve adequate cash flow coverage ratios, despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of return on equity, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's and Moody's guideline ranges for the debt ratio, while an important indicator of an appropriate capital structure, should be referenced with regard to other financial metrics.

Table 7

	S&P	**Moody's**
	"4"	"Medium Risk"
FFO Interest Coverage	3.5-4.2X	3.5-6.0X
FFO/Average Total Debt	20.0-28.0%	22.0-30.0%

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006 and Moody's, *Moody's Rating Methodology: Global Regulated Electric Utilities*, March 2005.

I have estimated the FFO Interest Coverage and FFO/Total Debt ratios for Yukon Electrical based on common equity ratios of 47.5% and 52.5%. Specifically, I estimated the ratios using capital structures containing 47.5% and 52.5% equity, each in conjunction with a benchmark return on equity of 8.75%, Yukon Electrical's forecast

embedded cost of debt of 6.83% and forecast depreciation expense for 2009. In interpreting the results, it is important to recognize, as noted earlier, that the guidelines are not applied mechanistically.

Yukon Electrical's indicated FFO Interest Coverage ratios are 4.2X and 4.7X at 47.5% equity and 52.5% equity respectively. The indicated ratios are at the upper end of S&P's guideline range at a 47.5% common equity ratio and above the upper end of the range at a 52.5% common equity ratio. In each case, the calculated FFO coverage ratio is below the mid-point (4.75X) of Moody's guideline range. The estimated FFO/Total Debt ratios (22% and 25% at common equity ratios of 47.5% and 52.5% respectively) are within both S&P's and Moody's guideline ranges. Table 8 (below) indicates that an FFO Interest Coverage ratio for Yukon Electrical in the range of 4.2X to 4.7X would be higher than the achieved ratios of other Canadian transmission and distribution utilities (3.8X), which would be reasonable given Yukon Electrical's higher business risk. However, at a 52.5% equity ratio, the ratio would be similar to, but still lower than, the average FFO coverage ratios achieved by the low risk (A rated) U.S. electric utilities (4.9X).

As shown in Table 8, an FFO/Total Debt ratio for Yukon Electrical of 22% to 25% would be higher than the average achieved FFO/Total Debt ratios of other Canadian electric utilities (17.5%), but, at a 47.5% equity ratio, similar to the average of the low risk (A rated) U.S. electric utilities (22.3%).

Table 8

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	FFO Interest Coverage (2004-2006)	FFO to Total Debt (2004-2006)
Canadian Electric Utilities:			
All	A/Baa1/A-	3.5X	17.5%
Transmission & Distribution	A/Baa1/A-	3.8X	17.5%
Integrated	A(low)/Baa2/BBB+	3.3X	14.2%
U.S. A-rated Electric	na/A2/A	4.9X	22.3%

Source: Schedules 2 and 3.

Although S&P no longer publishes a guideline range for pre-tax (or EBIT)[24] interest coverage ratios,[25] it is still considered an important quantitative financial ratio by all three debt rating agencies (S&P, DBRS and Moody's). It has also been a key ratio considered by regulators (e.g., EUB and BCUC) in assessing capital structures. Moreover, in contrast to the FFO coverages, which are driven in part by depreciation expense, EBIT coverage is more a function of capital structure and return on equity.

S&P's most recent EBIT interest coverage guideline range for an A rating at a "4" business profile score was 3.3X to 4.0X.[26] At common equity ratios of 47.5% and 52.5%, the benchmark return on equity of 8.75%, Yukon Electrical's embedded debt cost of 6.83%, and an income tax rate of 34%,[27] Yukon Electrical's EBIT interest coverage would be in the range of approximately 2.8 to 3.2X. Table 9 below demonstrates the calculation of the EBIT interest coverage at a 50% common equity ratio.

Table 9

	Cost Rate	**Percentage**	**Weighted Component**
	(1)	(2)	(3)=(1) x (2)
Debt	6.83%	50.00%	3.42%
Common Equity	8.75%	50.00%	4.375%
Tax Rate (t)	34%		
Income Tax = 4.38 x (t/(1-t))			2.25%
Pre-Tax Return			10.04%
EBIT Interest Coverage[1/]			2.94X

[1/] EBIT Interest Coverage = Pre-Tax Return ÷ Weighted Debt Component.

The indicated EBIT interest coverage ratios of 2.8X to 3.2X at common equity ratio of 47.5-52.5% are below the bottom end of S&P's guideline range for an A rating.

[24] Earnings before Interest and Taxes.
[25] Moody's has not, to my knowledge, ever published an EBIT interest coverage guideline.
[26] S&P, *Utilities and Perspectives*, June 1999. The EBIT interest coverage guideline ranges were excluded from the quantitative guidelines after June 2004, but the actual EBIT interest coverage ratios continue to be provided in the annual utilities' *CreditStats* published by S&P.
[27] Statutory combined Federal (19%) and Yukon Territory (15%) rate as of 2009.

Table 10 below indicates that an EBIT interest coverage ratio in the range of 2.8X to 3.2X would be somewhat higher than the average for the other Canadian electric utilities. Over the period 2004-2006, the average EBIT coverage ratios for all major Canadian electric utilities and transmission and distribution utilities with rated debt were 2.7X and 2.5X respectively. In light of Yukon Electrical's higher than average business risk, an EBIT interest coverage ratio higher than the Canadian electric utility industry average should be expected. A ratio of 3.2X, however, would still be lower than the 3.6X average EBIT interest coverage ratio achieved by low risk (A rated) U.S. electric utilities, which, is partly attributable to the low risk U.S. utilities' higher achieved returns on equity (11.8%, see Schedule 2) relative to the 8.75% benchmark return on equity.

Table 10

Electric Utilities with Rated Debt	Ratings DBRS/Moody's/S&P	EBIT Interest Coverage (2004-2006)
Canadian Electric Utilities:		
All	A/Baa1/A-	2.7X
Transmission & Distribution	A/Baa1/A-	2.5X
Integrated	A(low)/Baa2/BBB+	2.6X
U.S. A-rated Electric	na/A2/A	3.6X

Source: Schedules 2 and 3.

In summary, my estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of the 47.5% to 52.5% range (i.e. at 52.5%).

VIII. DEBT RATING AGENCY COMMENTARY

As indicated in Sections VI and VII above, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a utility. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity base on which it is allowed to earn, but also the allowed return on equity and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S. The investment community has also indicated to the National Energy Board that it believes the financial parameters adopted for regulated companies are too low.[28]

DBRS

DBRS has commented generally on the relatively low common equity ratios and returns that are being allowed in Canada. In a May 2003 commentary, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, DBRS noted that it would like to see both the deemed common equity ratios increased as well as increases in allowed returns to levels more consistent with U.S. returns.

In December 2004, subsequent to the EUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity ratios and equity returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (return on equity) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

[28] National Energy Board, *Canadian Hydrocarbon Transportation System*, August 2005, June 2006 and July 2007.

In DBRS' *Year in Review and Outlook for 2007* (January 2007), the company cited two challenges faced by Canadian regulated utilities in 2006 that were expected to continue to put pressure on the sectors' credit metrics in the coming year. The first challenge was the historically low level of allowed rates of return which put downward pressure on earnings and cash flow. For 2007, DBRS expected that, in some cases, the low rates of return would be offset by higher equity ratios.[29] The second challenge was the need to finance increased capital expenditures to replace aging infrastructure and to meet increased demand due to growth in business.[30]

Standard and Poor's

With respect to S&P, in early March 2003, the debt rating agency announced that it was reevaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation).

S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

Like DBRS, S&P has made references to the low deemed equity ratios and equity returns allowed in the EUB's Generic Cost of Capital decision for Alberta utilities. For example, S&P commented on the thin equity layers (and the low returns) allowed the ATCO group of utilities after the EUB decision, stating,

[29] In its July 24, 2007 report on Toronto Hydro, DBRS stated "The return on equity of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower return on equity is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009."

[30] Other DBRS reports have referenced the low approved returns on equity as a "challenge" for Canadian utilities, i.e., ATCO Ltd. (January 2007), CU Inc. (January 2007), Union Gas (March 2007) and FortisAlberta (May 2007).

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004)

In a more recent report for Yukon Electrical's parent, CU Inc. (rated A), S&P stated in reference to the company's businesses in Alberta,

> Rates of return and deemed equity layers are somewhat low compared with those of global peers, but are similar to those of other Canadian utilities (S&P, *CU Inc.*, October 26, 2007)

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[31] As indicated above, the "aggressive leverage" is largely a result of regulatory directives.

In sum, the debt rating agencies consider the allowed common equity ratios for Canadian utilities to be relatively thin and the allowed ROEs to be relatively low. (Actual equity ratios will generally track allowed equity ratios, as utilities have no incentive to maintain higher equity ratios than allowed by the regulator for ratemaking purposes.)

Based on the views of the debt rating agencies, in the aggregate, the allowed and actual common equity ratios of other Canadian electric utilities would be on the low side as a point of departure for estimating a reasonable capital structure for Yukon Electrical. In that context, the upper end of a 47.5%-52.5% common equity range would be reasonable for Yukon Electrical and allow the benchmark return on equity to be applied without an incremental equity risk premium.

[31] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

IX. CHOICE OF CAPITAL STRUCTURE AND RISK PREMIUM

As previously discussed, I have estimated the common equity ratio that would fully compensate for Yukon Electrical's business risk, i.e., the upper end of a range of 47.5% to 52.5%. A common equity ratio of 52.5% represents a material departure from the actual common equity ratio of approximately 40% that has been historically maintained. To reach an actual common equity ratio of 52.5%, there would need to be a material equity infusion would be required to bring the actual equity ratio up to 52.5%.[32]

There is a critical concern, however, with this approach. While the shareholders may be willing to accept the Alberta benchmark return on equity as a point of departure for setting the allowed return on equity for Yukon Electrical, the benchmark return on equity is viewed as relatively low. The very fact that shareholders in Yukon Electrical (as well as shareholders in other Canadian utilities with similar allowed returns) consider the allowed returns for Canadian utilities to be to low to be compatible with the fair return standard begs the question of why utility investors would want to invest additional equity in order to have the opportunity to earn an inadequate return. In this regard, Canadian utility returns compare unfavourably to the returns that are being allowed for U.S. utilities. The average return on equity that has been allowed by state regulators for U.S. electric and gas utilities over the period 2005-2008Q1 has been approximately 10.4%, approximately 1.5 percentage points higher than the corresponding allowed returns for Canadian utilities. The returns allowed by the Federal Energy Regulatory Commission for (lower risk) transmission operations have been in the approximate range of 10.75-13.8%.[33]

[32] In principle, the common equity ratio could be simply deemed to be 52.5% irrespective of Yukon Electrical's actual common equity ratio. This is not without precedent. For example, the Ontario Energy Board has deemed common equity ratios of 40% for all of the electricity distributors under its jurisdiction. The actual equity ratios of the distributors at the end of the 2006 ranged from negative to 100%. However, Canadian regulators generally have been reluctant to adopt deemed common equity ratios that are materially higher than the actual equity ratios that are maintained by the utilities.

[33] The Conference Board of Canada, in reference to allowed returns for U.S. electricity transmission, underscored the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled Electricity Restructuring: Opening Power Markets, the Conference Board stated,

This consideration leads me to recommend that Yukon Electrical move to an equity ratio of 47.5%, with the difference between a 47.5% equity ratio and the 52.5% ratio that would fully compensate for Yukon Electrical's business risks reflected in an incremental equity risk premium. The estimate of the risk premium recognizes that within the five percentage point range of equity ratios (from 47.5% to 52.5%), the overall cost of capital would be relatively constant. In other words, as the equity ratio moves from 52.5% to 47.5%, the overall cost of capital would not change; the decrease in the equity ratio would be offset by an increase in the common equity return. As demonstrated in Table 11 below, a decrease in the common equity ratio from 52.5% to 47.5% increases the equity return from the 8.75% benchmark return on equity to approximately 9.25%.[34]

Table 11

	Proportion	Cost	Weighted Component
Debt	47.50%	6.15%	2.92%
Equity	52.50%	8.75%	4.59%
			7.52%
		Tax Allowance at 34%	2.37%
		Pre-Tax Cost of Capital	9.88%
Move Equity Proportion to 47.5%			
Pre-Tax Cost of Capital Remains Unchanged at:			9.88%
Less: Weighted Interest Component (6.15% x 52.5%)			3.23%
Pre-Tax Weighted Equity Component			6.65%
Less: Tax at 34%			2.26%
After-Tax Weighted Equity Component			4.39%
ROE at 47.5% Equity			
(After-Tax Weighted Equity Component / 47.5%)			**9.24%**

Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.

The same conclusions are relevant to distribution and generation.

[34] Based on a cost of debt equal to the 4.55% forecast 30-year Long Canada yield plus the November 30, 2007 indicated spread for a new 30-year CU Inc. debt issue of 130 basis points, and the 2009 statutory corporate income tax rate of 34%.

The indicated required increase in the common equity return due to the lower equity ratio, and thus the required incremental equity risk premium for Yukon Electrical at a 47.5% ratio, is approximately 0.50%. A 0.50% incremental equity risk premium results in a recommended ROE for Yukon Electrical of 9.25%.

X. CONCLUSIONS

- I have relied on the approach adopted by the EUB and NEB with respect to capital structure, that is, I have estimated the capital structure that fully reflects the business risk of Yukon Electrical.

- The return on equity that would be applied to the capital structure that fully compensates for Yukon Electrical's business risk is the EUB's benchmark return on equity established in Decision 2004-052, as adjusted for changes in the forecast long-term Canada bond yield.

- I recommend that the YUB adopt a single benchmark return on equity for both test years, 2008-2009, of 8.75%, based on the average forecast of long-term Canada bond yields over the period of 4.5%.

- The capital structure for Yukon Electrical should:
  - Respect the stand-alone principle;
  - Be compatible with Yukon Electrical's business risks; and,
  - Maintain Yukon Electrical's creditworthiness and financial integrity.

- Yukon Electrical's business risks are higher than those of the typical Canadian electricity distribution utility and higher than average within the spectrum of Canadian utilities.

- The actual and allowed capital structures of Yukon Electrical's peers, both Canadian and U.S., indicate that, in isolation, the common equity ratio that would equate Yukon Electrical to a benchmark utility would be no less than 50%; taking explicit account of U.S. utilities' considerably higher ROEs relative to the benchmark ROE of 8.75% supports an equity ratio in excess of 47.5%.

- Debt rating agency guidelines for the debt ratio compatible with Yukon Electrical's level of business risk support a common equity ratio in the range of 45-55%.

- Estimates of the various financial metrics for Yukon Electrical, with emphasis on EBIT coverage, in conjunction with the guideline ranges and the comparative ratios for other electric utilities, indicate that the common equity ratio for Yukon Electrical should be focused on the upper end of a 47.5% to 52.5% range (i.e. at 52.5%).

- The concerns expressed by the debt rating agencies, as well as other capital market participants, that the common equity ratios of Canadian utilities are too thin (and the ROEs are too low) further support the focus on the upper end of common equity ratio range for Yukon Electrical of 47.5% to 52.5%.

- In sum, the upper end of a 47.5-52.5% common equity range would be reasonable for Yukon Electrical and would allow a benchmark return on equity to be applied without an incremental equity risk premium.

- One critical factor militates against increasing the actual common equity ratio of Yukon Electrical to 52.5%: To require shareholders to commit additional equity capital to have the opportunity to earn an equity return perceived as too low is fundamentally incongruous.

- To address this factors, I recommend increasing the actual common equity ratio of Yukon Electrical to 47.5% and allowing an incremental equity risk premium of 0.50% above the benchmark return on equity to compensate for the difference between a 47.5% equity ratio and the 52.5% common equity ratio that would fully compensate for the business risks of Yukon Electrical. At a 47.5% common equity ratio, the allowed ROE for Yukon Electrical should be set at 9.25% for the 2008 and 2009 test years.

APPENDIX A
QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications, Papers and Presentations

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN & CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007
Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000

Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001

Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company/Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

1

2

Current Ratings and New Issue Indicated Spreads
Relative to the Benchmark 30 Year Government of Canada Bond for Selected Canadian Utilities

	Current Ratings April 1, 2007		4-10-06	6-12-06	9-5-06	11-6-06	1-2-07	2006 Average	4-2-07	7-3-07	10-9-07	11-26-07	2007 Average	4-1-08	2007-2008Q1 Average
	DBRS	S&P													
A Rated															
CU Inc.	A(high)	A	90	94	97	93	92	**93**	90	95	115	130	**108**	157	**117**
Enbridge Gas	A	A-	100	105	100	96	95	**99**	98	110	115	130	**113**	170	**125**
Enbridge Pipelines	A(high)	A-	100	105	100	96	95	**99**	98	105	115	130	**112**	170	**124**
Gaz Metro	A	A	89	94	99	95	97	**95**	94	92	115	135	**109**	172	**122**
Terasen Gas [1/]	A	A	na	na	na	na	na	**na**	na	122	135	145	**134**	168	**143**
TransCanada PipeLines	A	A-	117	120	120	116	115	**118**	115	130	140	160	**136**	215	**152**
Average	**A**	**A-**	**99**	**104**	**103**	**99**	**99**	**101**	**99**	**109**	**123**	**138**	**117**	**175**	**130**
Median	**A**	**A-**	**100**	**105**	**100**	**96**	**95**	**99**	**98**	**108**	**115**	**133**	**113**	**170**	**124**
Split Rated A/BBB															
EPCOR Utilities	A(low)	BBB+	129	132	133	130	135	**132**	130	136	170	185	**155**	255	**175**
Nova Scotia Power	A(low)	BBB	135	140	142	140	138	**139**	132	136	145	170	**146**	205	**158**
Terasen Gas [1/]	A	A	129	145	142	130	130	**135**	119	na	na	na	**119**	na	**119**
Union Gas	A	BBB+	118	123	120	114	107	**116**	109	109	120	150	**122**	185	**135**
Westcoast Energy	A(low)	BBB+	123	128	125	120	118	**123**	119	119	125	155	**130**	185	**141**
Average	**A(low)**	**BBB+**	**127**	**134**	**132**	**127**	**126**	**129**	**122**	**125**	**140**	**165**	**138**	**208**	**145**
Median	**A(low)**	**BBB+**	**129**	**132**	**133**	**130**	**130**	**131**	**119**	**128**	**135**	**163**	**136**	**195**	**141**
BBB Rated															
TransAlta	BBB	BBB	162	168	168	162	170	**166**	170	205	300	325	**250**	390	**278**

[1/] Terasen Gas was upgraded to A by S&P in June 2007 following Terasen's acquisition by Fortis Inc .
Source: RBC Capital Markets

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Electric Utilities			
AltaLink L.P.	1.8	11.4	3.1
CU Inc.	2.7	18.7	3.6
Enersource	2.1	16.7	3.8
ENMAX Corp.	6.4	46.3	8.1
EPCOR Utilities Inc.	3.0	23.4	4.2
FortisAlberta Inc.[2/]	2.3	17.5	3.0
FortisBC Inc.[2/]	2.2	10.9	2.8
Hamilton Utilities	3.4	32.0	4.7
Hydro One Inc.	3.2	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	26.1	5.7
Maritime Electric	2.5	12.9	2.6
Newfoundland Power [2/]	2.4	14.0	2.9
Nova Scotia Power	2.4	14.2	3.3
Toronto Hydro	2.7	17.5	3.4
Gas Distributors			
Enbridge Gas Distribution	2.1	12.5	3.0
Gaz Metropolitain	2.5	24.0	4.6
Pacific Northern Gas [4/]	2.4	26.4	3.2
Terasen Gas	2.0	9.7	2.4
Union Gas [3/]	2.1	12.8	2.8
Pipelines			
Enbridge Pipelines [3/]	3.3	17.2	3.1
Nova Gas Transmission Ltd.[3/]	2.4	18.5	2.8
TransCanada PipeLines Ltd.[3/]	2.6	15.7	2.8
Westcoast Energy Inc.	2.1	16.4	3.1
Medians			
Electric T&D	**2.7**	**17.5**	**3.8**
Electric Integrated	**2.5**	**14.2**	**3.3**
All Electric	**2.6**	**17.5**	**3.5**
Gas Distributors	**2.1**	**12.8**	**3.0**
All Companies	**2.4**	**17.2**	**3.1**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2/] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3/] FFO Coverage for 2003-2005

[4/] All data for 2004-2006 from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

Name	S&P Debt Rating	S&P Business Profile	Average 2004-2006 Debt Ratio	Average 2004-2006 EBIT Coverage	Average 2004-2006 FFO/Debt	Average 2004-2006 FFO Coverage	Average ROE 2004-2006
Alabama Power Co.	A	4	54.3	4.3	22.8	5.6	13.5
Central Hudson Gas & Electric Corp.	A	3	66.3	4.7	16.7	4.3	12.2
Consolidated Edison Co. of New York Inc.	A	2	54.8	2.8	18.7	3.9	10.0
Consolidated Edison Inc.	A	2	57.2	2.6	16.7	3.7	9.2
Duke Energy Carolinas LLC	A-	4	48.0	4.0	28.8	14.9	NA
Duke Energy Corp.	A-	5	48.7	3.2	19.8	3.9	9.9
Duke Energy Indiana Inc.	A-	4	56.7	3.1	17.6	4.6	8.8
Duke Energy Ohio Inc.	A-	5	38.7	4.5	23.2	5.6	11.0
Florida Power & Light Co.	A	4	41.1	5.9	34.1	7.7	11.7
FPL Group Inc.	A	5	51.8	2.7	22.3	4.5	12.4
Georgia Power Co.	A	4	56.0	4.6	22.0	6.1	14.1
Gulf Power Co.	A	4	54.5	3.7	20.9	4.6	12.2
Integrys Energy Group Inc.	A-	5	58.6	3.4	13.8	4.1	12.5
KeySpan Corp.	A-	3	61.8	3.5	16.2	3.9	10.4
Madison Gas & Electric Co.	AA-	4	52.4	4.5	20.4	5.1	10.6
MidAmerican Energy Co.	A-	5	52.4	4.4	26.0	5.8	14.2
MidAmerican Energy Holdings Co.	A-	4	74.9	1.9	11.1	2.5	13.2
Mississippi Power Co.	A	4	63.0	4.2	22.8	10.8	13.9
NSTAR	A+	1	65.4	3.5	22.6	4.9	13.3
NSTAR Electric Co.	A+	1	49.7	5.7	39.4	8.1	13.8
Orange and Rockland Utilities Inc.	A	2	70.8	3.6	16.9	3.9	NA
PacifiCorp	A-	5	59.0	2.5	15.0	3.7	7.0
PPL Electric Utilities Corp.	A-	3	51.0	3.1	26.2	4.9	NA
San Diego Gas & Electric Co.	A	5	54.8	5.0	25.9	6.7	16.3
SCANA Corp.	A-	4	57.6	2.5	22.5	4.2	11.4
South Carolina Electric & Gas Co.	A-	4	50.1	2.6	25.6	5.1	10.3
Southern Co.	A	4	57.0	3.8	22.3	5.3	14.9
Vectren Corp.	A-	4	60.4	2.7	15.9	3.9	10.5
Wisconsin Electric Power Co.	A-	4	52.5	4.8	25.0	6.8	11.8
Wisconsin Power & Light Co.	A-	4	48.1	3.6	31.1	5.9	9.9
Wisconsin Public Service Corp.	A	4	52.3	4.0	22.3	5.4	10.1
Mean	**A**	**4**	**55.5**	**3.7**	**22.1**	**5.5**	**11.8**
Median	**A**	**4**	**54.8**	**3.6**	**22.3**	**4.9**	**11.8**

Source: All from S&P: Research Insight; *Issuer Ranking: U.S. Integrated Electric Utility Companies, Strongest to Weakest,* November 1, 2007;
Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, November 9, 2007; and *Credit Stats,* September 2007.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures (DBRS)	A		A-	
	Issuer (S&P)				
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	Very conservative
	Senior Unsecured	A	A3	A	
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
TransCanada PipeLines	Senior Secured	A		A	Very conservative
	Senior Unsecured	A	A2	A-	
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Medians					
Electric T&D		**A**	**Baa1**	**A-**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**BBB+**	**Very conservative**
All Electric		**A**	**Baa1**	**A-**	**Very conservative**
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
All Companies		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES
(2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd.[4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Electric Utilities									
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55	
ATCO Electric		EUB							
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55	
EPCOR		EUB							
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55	
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55	
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55	
FortisBC Inc.	3/06; 11/07	BCUC	G-14-06; L-93-07	60.00	0.00	40.00	9.02	4.55	
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16	
Maritime Electric	1/08	IRAC	UE20937	57.31	0.00	42.69	10.00	na	
Newfoundland Power	12/07	NLPub	PU32 (2007)	54.01	1.15	44.84	8.95	4.60	1/
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na	2/
Northwest Territories Power Corp.	8/07	PUB of NWT	Decision 13-2007	52.26	0.00	48.59	9.25	4.60	3/
Ontario Electricity Distributors	12/06	OEB	Report of the Board	60.00	0.00	40.00	8.57	4.46	4/
Yukon Energy	10/05	YUB	OIC 1998/32; Order 2005-12, BCUC G-55-07	60.00	0.00	40.00	9.15	4.55	5/
Gas Distributors									
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55	
Enbridge Gas Distribution Inc	1/04; 1/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
Gaz Metropolitain	10/07	Régie	D-2007-116	54.00	7.50	38.50	9.05	4.78	
Pacific Northern Gas	11/07; 5/07	BCUC	L-93-07; G-55-07	56.20	3.80	40.00	9.27	4.55	
Terasen Gas	3/06; 11/07	BCUC	G-14-06; L-93-07	65.00	0.00	35.00	8.62	4.55	
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23	
Gas Pipelines									
Alberta Natural Gas	11/07; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.72	4.55	
Foothills Pipe Lines (Yukon) Ltd.	11/07; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.72	4.55	
TransCanada PipeLines	11/07; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.72	4.55	
Trans Quebec & Maritimes Pipeline	11/07	NEB	RH-2-94	70.00	0.00	30.00	8.72	4.55	
Westcoast Energy	11/07; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.72	4.55	

1/ The settlement agreement specifying ROE and capital structure was approved by the PUB.

2/ A negotiated settlement to be filed with the UARB would implement a fuel adjustment clause and reduce the return on equity to 9.35% if approved.

3/ The capital structure of NTPC includes no cost capital (-.85%).

4/ The 8.57% ROE is for rates to be in effect as of May 2008. As per the 12/06 Report of the Board, the ROE is to be based on the January 2008 *Consensus Forecasts* and the January 2008 spread.

5/ The YUB set YEC's risk premium at the mid-point of the FortisBC risk premium (40bp) and that of PNG (65bp) as established by BCUC G-55-07. By Order in Council, YEC's ROE is then reduced from the "fair return on common equity" by 0.50%.

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Utilities																			
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	1/	1/	1/	1/	1/	1/	9.40	9.60	9.50	8.93	8.51	8.75
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	na
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	1/	2/	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**
Gas Distributors																			
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	9.62	8.54	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**9.08**	**8.59**	**8.77**
Gas Pipelines (NEB)																			
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**	**8.72**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.07**	**8.66**	**8.78**

1/ Negotiated settlement, details not available.
2/ Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED RETURNS ON EQUITY FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.61	4.08
1991	13.56	9.72	3.84	12.51	8.14	4.37
1992	12.94	8.68	4.26	12.06	7.67	4.39
1993	12.16	7.86	4.30	11.37	6.59	4.78
1994	11.50	8.69	2.81	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.84	6.66	4.18	11.34	6.58	4.76
1998	10.15	5.59	4.56	11.59	5.54	6.05
1999	9.50	5.72	3.78	10.74	5.91	4.83
2000	9.79	5.71	4.08	11.41	5.88	5.53
2001	9.68	5.77	3.91	11.04	5.50	5.54
2002	9.62	5.67	3.95	11.10	5.41	5.69
2003	9.71	5.31	4.40	10.98	5.03	5.95
2004	9.59	5.11	4.48	10.73	5.08	5.65
2005	9.51	4.38	5.13	10.50	4.52	5.98
2006	9.07	4.33	4.74	10.39	4.93	5.46
2007	8.66	4.30	4.36	10.30	4.80	5.50
2008q1	8.78	4.10	4.68	10.37	4.35	6.02
Means:						
1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.75**	**4.41**
1994-1998	**11.20**	**7.42**	**3.78**	**11.41**	**6.62**	**4.80**
1999-2007	**9.46**	**5.14**	**4.31**	**10.80**	**5.23**	**5.57**

[1/] 2008 ROE represents results for the full year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; www.federalreserve.gov; www.ustreas.gov.

YUB-YECL-34

Reference: Forecast income taxes, YECL Application, pages 1-5 - 1-6, Section 10 – Income Tax, page 10-1

The deferral accounts for which Yukon Electrical is seeking approval meet the standard criteria for the establishment of a deferral account:

(a) Costs are not under the control of the company and are not reasonably forecastable; or
(b) An error in forecasting could produce a loss or gain of a substantial magnitude.

The Board wants to better understand the request for a deferral account for income taxes.

Request:

(a) Please confirm the following calculations derived from the table on page 10-1

	Amount	Increase	Percentage Increase
2013	$248,000	$555,000	n/a
2014	$704,000	$456,000	184%
2015	$828,000	$124,000	18%

(b) YECL has forecast substantial increases in income taxes for the test period. Please discuss the factors that would lead to the increases noted above.

(c) Please provide additional detail on the position of YECL that income taxes require the use of deferral accounts.

Response:

(a) Confirmed.

(b) Yukon Electrical's utility earnings before tax are increasing for the test period primarily as a result of growth in rate base as well as amount of rate base being

financed by the shareholder. Depreciation expense, which is added back to utility earnings before tax for the purpose of calculating taxable income, is also significantly higher for the test period primarily as the result of the reinstatement of the provision for future removal and site restoration in depreciation rates.

(c) Yukon Electrical has not requested a deferral account for income taxes in this Application and does not believe such a deferral account is required.

YUB-YECL-35

Reference: Increases in forecast property, YECL Application, Section 6 – Taxes Other than Income, page 6-1

The increases forecast during the test period are primarily due to planned capital work on the downtown office building in Whitehorse and the Fish Lake Unit #1 building, as well as inflation.

The Board seeks additional detail regarding the forecast increases in property taxes.

Request:

Please provide a schedule that details the forecast increases in property taxes between increases due to capital work and increases due to inflation.

Response:

Please see table below showing the increases to the base level of taxes for 2012 due to inflation and new capital.

	Actual	Test Period		
	2012	2013	2014	2015
Base	250	250	250	250
Inflation		5	5	5
Increases Due to Capital		2	10	18
Schedule 1.1, line 11	250	257	265	273

YUB-YECL-36

Reference: Fish Lake Unit #2 Penstock Replacement, YECL Application, Business Case #1, page 2

Replacement of the current above ground wood stave penstock with a new penstock. The new penstock will be installed in the same general area as the existing penstock. Civil works will be completed for the new penstock as an 'in ground' installation. Water in this section of the Fish Lake hydro system will be passed through the overflow spillway at Headpond #2 to maintain water flow through the system to McIntyre Creek until the project is complete.

YECL has included demand side management costs of $204,000, $143,000, $135,000, $522,000, and $730,000, respectively for 2011, 2012, 2013, 2014, and 2015.

Request:

(a) The current above ground wood stave penstock is to be replaced with an *in ground* installation. Please provide an explanation as to what is meant by an *in ground* installation.

(b) Please provided a comparison of costs between *in ground* and *above ground* installations.

(c) Does the decision to go with the in ground installation preclude or render any other associated apparatus inappropriate or require additions to Fish lake hydro system? Please explain.

Response:

(a) In ground means below ground or buried. An in ground installation was chosen to eliminate the vandalism Yukon Electrical has experienced with the above ground penstock.

(b) A consultant completed preliminary estimates of both options. An in ground steel penstock installation would cost approximately $530,000. A steel penstock supported above ground on concrete piers and steel saddles would cost approximately $560,000.

(c) No changes to the Fish Lake Hydro system were required due to the in ground installation.

YUB-YECL-37

Reference: Business Cases #1 2, 7, 9 and 28; Fish Lake-related projects, Yukon Electrical Application, Business Case 2, page 3

In March 2010, a catastrophic failure of Fish Lake Unit #1 plant occurred, irreparably damaging the facility. In consideration of Yukon Electrical's ongoing water management responsibilities, existing hydro system infrastructure, the continued operation of Fish Lake Unit #2 as well as the ongoing declarations of diesel being on-the-margin; returning Fish Lake Unit #1 to operation has been determined to be the best option available.

Request:

(a) For each of the business cases listed above, please provide an economic analysis similar to what was provided in business case #2, the Fish Lake Unit #1 turbine and building replacement.

(b) Please provide a economic analysis similar to what was provided in business case #2, which considers all Fish Lake-related business cases in total, i.e. $9,653 million:

i. Business case #1 - $556,000,
ii. Business case #2 - $3,908,000,
iii. Business case #7 - $1,720,000,
iv. Business case #9 - $1,640,000, and
v. Business case #28 - $1,829,000.

(c) Please confirm whether there are additional expenses related to the Fish Lake hydro system that have arisen since Yukon Electrical filed its application.

(d) Once all the work has been completed and the Fish Lake infrastructure has been updated with current engineered standards and equipped with more efficient apparatus please explain why the forecast Fish Lake hydro generation in the test period should not be greater than the base hydro generation for Fish Lake, which was approved in Board Order 2009-2.

Response:

(a) Please refer to attachment YUB-YECL-37 Attachment 1 for Levelized Cost of Energy (LCOE) calculations. The tabs are:

- **YUB-YECL-37(a) BC1** for Penstock 2 replacement;
- **YUB-YECL-37(a) BC2** for Unit 1 replacement;
- **YUB-YECL-37(a) BC7** for Fish Lake Dike Upgrade;
- **YUB-YECL-37(a) BC9** for Ditch #3 Diversion Structure; and
- **YUB-YECL-37(a) BC27** for Water License Renewal.

The summarized results are as follows:

Business Case	LCOE (Real) (¢/kWh)
1 Penstock Replacement	1.1
2 Unit 1 Replacement	5.1
7 Fish Lake Dike Upgrade	1.2
9 Ditch #3 Diversion Structure	1.2
27 Water License Renewal	2.6

(b) Please refer to attachment YUB-YECL-37 Attachment 1, tab YUB-YECL-37(b) - LCOE for the LCOE calculation. The LCOE when all business case costs are considered at the Fish Lake facility is 11.5¢/kWh.

Yukon Electrical considers an LCOE of 11.5¢/kWh to be a good indicator of these projects' economic viability and compares favorably with other small hydro projects referenced by Yukon Energy in its 20-Year Resource Plan[1].

[1] Reproduced from YEC's 20-Year Resource Plan: 2011-2030, Table 7-1: Summary of Potential Hydro Sites:

Small Hydro Projects (<10MW)		Installed Capacity (MW)	Annual Energy (GWh)	Capital Cost (Million $2009)	Levelized Cost (¢/kWh)
20-23 ¢/kWh	Moon Lake	5.8	32.9	126.8	19.9
	Tutshi River	4.2	30.3	135.5	23.1
	Tutshi (Windy Arm)	5.9	39.4	164.9	21.6
	Pine Creek at Atlin	3.5-8	23-52	NA	NA

Given forecast Yukon load growth is expected to be met with a generation mix of hydro and diesel, Yukon Electrical has also performed a Net Present Value analysis of offset diesel expense for all Business Case-related costs.

Table 4.1-2 from Yukon Energy's most recent GRA Compliance Filing provides a forecast Yukon Integrated System generation mix at different grid loads. By keeping Fish Lake in service, a portion (58%-78%) of Fish Lake's output will offset the forecast diesel expense.

Please refer to YUB-YECL-37 Attachment 1, tab YUB-YECL-37(b) – NPV. The Net Present Value of diesel savings is $23.8M over the life of the asset. Also, the Cumulative Present Value (graph) shows that diesel savings will surpass the project expenses in the eighth year.

(c) Confirmed. The costs for the Fish Lake Water License have increased since Yukon Electrical filed its Application. Please refer to YUB-YECL-53(a) Attachment 1 for details. There are no other additional expenses forecast for the Fish Lake Hydro system in addition to those included in the Application.

(d) The forecast Fish Lake hydro generation should not be greater than 8.73GWh approved in Board Order 2009-02.

Please refer to YUB-YECL-37 Attachment 1, tab YUB-YECL-37(d) for historical output of Fish Lake, from 1960 to 2012. Included in this attachment are two additional tables: (1) 10-year averages for each decade up to 2009, and (2) multi-decade historical averages for decreasing periods up to 2009.

The observations that can be made from this information are as follows:

1. The 50-year historical average is 8.48GWh;

2. Only two time periods (the 1960s and 1970s) exceed the 8.73GWh approved by the Board in Order 2009-02; and

3. There is a high variability in output with the lowest average 10-year output of 7.42GWh occurring in the 2000 – 2009 time period.

These observations clearly show the 8.73GWh is higher than what should be forecast based on the use of historical averages.

Yukon Electrical does not have any actual experience with the new equipment. It is not yet clear what the efficiency gain will be and is subject to operational flows. Yukon Electrical believes the best forecast available for purposes of this Application is to remain at the Board-approved output of 8.73GWh rather than decreasing the expected output at the facility to better match the historical average and then offsetting it with potential efficiency gains.

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	B.C. 1 LCOE - Fish #2 Penstock Replacement - YUB-YECL-37(a)
Year	2011
# Years	40
Capital Cost ($)	$ 556,000
***Et* = Electricity generation in year *t* (kWh)**	3,088,632

O&M	O&M Growth
$ 1,000	2.000%

2011	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	8%

Discount Rate	9.037%
Real Discount	6.899%

t	**[1]**	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**	**[11]**	**[12]**	**[13]**	**[14]**	**[15]**	**[16]**	**[17]**	**[18]**	**[19]**
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Remaining Ratebase	556,000	549,050	535,150	521,250	507,350	493,450	479,550	465,650	451,750	437,850	423,950	410,050	396,150	382,250	368,350	354,450	340,550	326,650	312,750
Return	20,295	40,083	39,068	38,053	37,039	36,024	35,009	33,994	32,980	31,965	30,950	29,935	28,921	27,906	26,891	25,876	24,862	23,847	22,832
Depreciation	6,950	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900
Income Tax	(1,844)	(3,275)	(2,491)	(1,790)	(1,164)	(607)	(114)	320	700	1,030	1,314	1,557	1,761	1,929	2,064	2,169	2,247	2,299	2,327
It* = Investment Expenditures in Year *t	25,401	50,708	50,477	50,164	49,775	49,317	48,795	48,214	47,579	46,895	46,164	45,392	44,581	43,735	42,855	41,946	41,008	40,046	39,059
Mt* = Operations and Maintenance in Year *t	1,000	1,020	1,040	1,061	1,082	1,104	1,126	1,149	1,172	1,195	1,219	1,243	1,268	1,294	1,319	1,346	1,373	1,400	1,428
It + Mt	26,401	51,728	51,517	51,225	50,857	50,421	49,921	49,363	48,751	48,090	47,383	46,636	45,849	45,028	44,175	43,292	42,381	41,446	40,488
(It + Mt) / (1+r)^t	24,213	43,509	39,740	36,239	32,997	30,003	27,243	24,706	22,378	20,245	18,294	16,513	14,889	13,410	12,066	10,845	9,737	8,733	7,824
Et / (1+r)^t	2,889,295	2,702,823	2,528,386	2,365,206	2,212,558	2,069,762	1,936,182	1,811,223	1,694,328	1,584,978	1,482,685	1,386,994	1,297,479	1,213,741	1,135,408	1,062,130	993,581	929,456	869,470
Levelized Cost of Energy ($/kWh)	**0.011**																		

Income Tax Calculation

Undepreciated Capital Cost	556,000	533,760	491,059	451,774	415,633	382,382	351,791	323,648	297,756	273,936	252,021	231,859	213,310	196,246	180,546	166,102	152,814	140,589	129,342
Capital Cost Allowance (CCA)	22,240	42,701	39,285	36,142	33,251	30,591	28,143	25,892	23,820	21,915	20,162	18,549	17,065	15,700	14,444	13,288	12,225	11,247	10,347
Final Undepreciated Capital Cost	**533,760**	**491,059**	**451,774**	**415,633**	**382,382**	**351,791**	**323,648**	**297,756**	**273,936**	**252,021**	**231,859**	**213,310**	**196,246**	**180,546**	**166,102**	**152,814**	**140,589**	**129,342**	**118,995**
Taxable Return	16,094	31,785	30,981	30,176	29,371	28,567	27,762	26,957	26,152	25,348	24,543	23,738	22,934	22,129	21,324	20,520	19,715	18,910	18,106
CCA	22,240	42,701	39,285	36,142	33,251	30,591	28,143	25,892	23,820	21,915	20,162	18,549	17,065	15,700	14,444	13,288	12,225	11,247	10,347
Taxable Income	(6,146)	(10,916)	(8,304)	(5,966)	(3,879)	(2,024)	(381)	1,065	2,332	3,433	4,381	5,190	5,869	6,429	6,881	7,231	7,490	7,663	7,758
Income Tax Payable	**(1,844)**	**(3,275)**	**(2,491)**	**(1,790)**	**(1,164)**	**(607)**	**(114)**	**320**	**700**	**1,030**	**1,314**	**1,557**	**1,761**	**1,929**	**2,064**	**2,169**	**2,247**	**2,299**	**2,327**

[20] 2030	**[21]** 2031	**[22]** 2032	**[23]** 2033	**[24]** 2034	**[25]** 2035	**[26]** 2036	**[27]** 2037	**[28]** 2038	**[29]** 2039	**[30]** 2040	**[31]** 2041	**[32]** 2042	**[33]** 2043	**[34]** 2044	**[35]** 2045	**[36]** 2046	**[37]** 2047	**[38]** 2048	**[39]** 2049	**[40]** 2050	**[41]** 2051
298,850	284,950	271,050	257,150	243,250	229,350	215,450	201,550	187,650	173,750	159,850	145,950	132,050	118,150	104,250	90,350	76,450	62,550	48,650	34,750	20,850	6,950
21,817	20,802	19,788	18,773	17,758	16,743	15,729	14,714	13,699	12,684	11,670	10,655	9,640	8,625	7,611	6,596	5,581	4,566	3,552	2,537	1,522	507
13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900	13,900
2,334	2,321	2,290	2,242	2,179	2,101	2,010	1,907	1,793	1,669	1,536	1,393	1,243	1,086	922	752	576	394	208	18	(177)	(375)
38,052	37,024	35,978	34,915	33,837	32,744	31,639	30,521	29,393	28,254	27,105	25,948	24,784	23,611	22,432	21,247	20,057	18,861	17,660	16,455	15,245	14,032
1,457	1,486	1,516	1,546	1,577	1,608	1,641	1,673	1,707	1,741	1,776	1,811	1,848	1,885	1,922	1,961	2,000	2,040	2,081	2,122	2,165	2,208
39,508	38,510	37,494	36,461	35,414	34,353	33,279	32,195	31,099	29,995	28,881	27,760	26,631	25,496	24,355	23,208	22,057	20,901	19,741	18,577	17,410	16,240
7,002	6,259	5,589	4,984	4,440	3,950	3,509	3,114	2,758	2,440	2,155	1,899	1,671	1,467	1,285	1,123	979	851	737	636	547	468
813,355	760,862	711,757	665,821	622,850	582,652	545,048	509,871	476,964	446,182	417,386	390,448	365,249	341,676	319,625	298,996	279,699	261,648	244,761	228,965	214,188	200,364
118,995	109,475	100,717	92,660	85,247	78,427	72,153	66,381	61,070	56,185	51,690	47,555	43,750	40,250	37,030	34,068	31,342	28,835	26,528	24,406	22,453	20,657
9,520	8,758	8,057	7,413	6,820	6,274	5,772	5,310	4,886	4,495	4,135	3,804	3,500	3,220	2,962	2,725	2,507	2,307	2,122	1,952	1,796	1,653
109,475	**100,717**	**92,660**	**85,247**	**78,427**	**72,153**	**66,381**	**61,070**	**56,185**	**51,690**	**47,555**	**43,750**	**40,250**	**37,030**	**34,068**	**31,342**	**28,835**	**26,528**	**24,406**	**22,453**	**20,657**	**19,005**
17,301	16,496	15,691	14,887	14,082	13,277	12,473	11,668	10,863	10,059	9,254	8,449	7,645	6,840	6,035	5,230	4,426	3,621	2,816	2,012	1,207	402
9,520	8,758	8,057	7,413	6,820	6,274	5,772	5,310	4,886	4,495	4,135	3,804	3,500	3,220	2,962	2,725	2,507	2,307	2,122	1,952	1,796	1,653
7,781	7,738	7,634	7,474	7,262	7,003	6,700	6,358	5,978	5,564	5,119	4,645	4,145	3,620	3,073	2,505	1,918	1,314	694	59	(589)	(1,250)
2,334	**2,321**	**2,290**	**2,242**	**2,179**	**2,101**	**2,010**	**1,907**	**1,793**	**1,669**	**1,536**	**1,393**	**1,243**	**1,086**	**922**	**752**	**576**	**394**	**208**	**18**	**(177)**	**(375)**

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	B.C. 2 LCOE - Fish #1 Turbine and Building - YUB-YECL-37(a)
Year	2014
# Years	37
Capital Cost ($)	$ 3,908,000
***Et* = Electricity generation in year*t* (kWh)**	5,641,368

O&M	O&M Growth
$ 50,000	2.000%

2014	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	8%

Discount Rate	9.037%
Real Discount	6.899%

t	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Remaining Ratebase	3,908,000	3,855,189	3,749,568	3,643,946	3,538,324	3,432,703	3,327,081	3,221,459	3,115,838	3,010,216	2,904,595	2,798,973	2,693,351	2,587,730	2,482,108	2,376,486	2,270,865	2,165,243
Return	142,650	281,444	273,733	266,023	258,312	250,601	242,890	235,179	227,469	219,758	212,047	204,336	196,625	188,915	181,204	173,493	165,782	158,071
Depreciation	52,811	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622
Income Tax	(12,960)	(23,086)	(17,717)	(12,924)	(8,662)	(4,887)	(1,561)	1,352	3,885	6,069	7,932	9,498	10,793	11,837	12,651	13,254	13,661	13,889
It* = Investment Expenditures in Yea*t	182,501	363,980	361,638	358,720	355,272	351,336	346,951	342,153	336,976	331,449	325,600	319,456	313,040	306,374	299,477	292,368	285,065	277,582
Mt* = Operations and Maintenance in Year*t	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755	60,950	62,169	63,412	64,680	65,974	67,293	68,639	70,012
It + Mt	232,501	414,980	413,658	411,780	409,393	406,540	403,259	399,587	395,559	391,203	386,550	381,625	376,452	371,054	365,451	359,662	353,704	347,594
(It + Mt) / (1+r)^t	213,231	349,043	319,094	291,318	265,625	241,911	220,071	199,994	181,569	164,686	149,241	135,127	122,248	110,508	99,819	90,095	81,259	73,237
Et / (1+r)^t	5,277,280	4,936,690	4,618,081	4,320,035	4,041,224	3,780,408	3,536,425	3,308,187	3,094,680	2,894,953	2,708,116	2,533,337	2,369,838	2,216,891	2,073,815	1,939,973	1,814,770	1,697,646
Levelized Cost of Energy* ($/kWh)	**0.051**																	

Income Tax Calculation

Undepreciated Capital Cost	3,908,000	3,751,680	3,451,546	3,175,422	2,921,388	2,687,677	2,472,663	2,274,850	2,092,862	1,925,433	1,771,398	1,629,686	1,499,312	1,379,367	1,269,017	1,167,496	1,074,096	988,169
Capital Cost Allowance (CCA)	156,320	300,134	276,124	254,034	233,711	215,014	197,813	181,988	167,429	154,035	141,712	130,375	119,945	110,349	101,521	93,400	85,928	79,053
Final Undepreciated Capital Cost	**3,751,680**	**3,451,546**	**3,175,422**	**2,921,388**	**2,687,677**	**2,472,663**	**2,274,850**	**2,092,862**	**1,925,433**	**1,771,398**	**1,629,686**	**1,499,312**	**1,379,367**	**1,269,017**	**1,167,496**	**1,074,096**	**988,169**	**909,115**
Taxable Return	113,120	223,182	217,068	210,953	204,839	198,724	192,609	186,495	180,380	174,266	168,151	162,037	155,922	149,807	143,693	137,578	131,464	125,349
CCA	156,320	300,134	276,124	254,034	233,711	215,014	197,813	181,988	167,429	154,035	141,712	130,375	119,945	110,349	101,521	93,400	85,928	79,053
Taxable Income	(43,200)	(76,952)	(59,056)	(43,081)	(28,872)	(16,290)	(5,204)	4,507	12,951	20,231	26,439	31,662	35,977	39,458	42,171	44,179	45,536	46,296
Income Tax Payable	**(12,960)**	**(23,086)**	**(17,717)**	**(12,924)**	**(8,662)**	**(4,887)**	**(1,561)**	**1,352**	**3,885**	**6,069**	**7,932**	**9,498**	**10,793**	**11,837**	**12,651**	**13,254**	**13,661**	**13,889**

* - For purposes of this response, Yukon Electrical has used the real discount rate for energy in the same way that the it was used in the Mayo B LCOE calculation provided by the Yukon Energy Corporation in its response to information request *CW-YEC-1-27(e) Attachment 1* during its 2012-2013 General Rate Application.

[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]
2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
2,059,622	1,954,000	1,848,378	1,742,757	1,637,135	1,531,514	1,425,892	1,320,270	1,214,649	1,109,027	1,003,405	897,784	792,162	686,541	580,919	475,297	369,676	264,054	158,432	52,811
150,361	142,650	134,939	127,228	119,517	111,807	104,096	96,385	88,674	80,963	73,253	65,542	57,831	50,120	42,409	34,699	26,988	19,277	11,566	3,855
105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622	105,622
13,952	13,863	13,634	13,277	12,802	12,218	11,534	10,758	9,898	8,959	7,949	6,873	5,736	4,543	3,299	2,008	673	(701)	(2,113)	(3,558)
269,934	262,134	254,195	246,127	237,941	229,646	221,252	212,765	204,193	195,544	186,823	178,036	169,188	160,285	151,330	142,328	133,283	124,197	115,075	105,919
71,412	72,841	74,297	75,783	77,299	78,845	80,422	82,030	83,671	85,344	87,051	88,792	90,568	92,379	94,227	96,112	98,034	99,994	101,994	104,034
341,346	334,975	328,492	321,910	315,240	308,491	301,673	294,795	287,864	280,888	273,874	266,828	259,757	252,664	245,557	238,440	231,317	224,192	217,070	209,953
65,960	59,364	53,390	47,984	43,095	38,677	34,688	31,087	27,841	24,914	22,279	19,907	17,773	15,855	14,132	12,585	11,197	9,953	8,838	7,840
1,588,082	1,485,589	1,389,710	1,300,020	1,216,118	1,137,631	1,064,210	995,527	931,276	871,173	814,948	762,352	713,151	667,125	624,069	583,793	546,115	510,869	477,898	447,055
909,115	836,386	769,475	707,917	651,284	599,181	551,246	507,147	466,575	429,249	394,909	363,316	334,251	307,511	282,910	260,277	239,455	220,299	202,675	186,461
72,729	66,911	61,558	56,633	52,103	47,934	44,100	40,572	37,326	34,340	31,593	29,065	26,740	24,601	22,633	20,822	19,156	17,624	16,214	14,917
836,386	**769,475**	**707,917**	**651,284**	**599,181**	**551,246**	**507,147**	**466,575**	**429,249**	**394,909**	**363,316**	**334,251**	**307,511**	**282,910**	**260,277**	**239,455**	**220,299**	**202,675**	**186,461**	**171,544**
119,234	113,120	107,005	100,891	94,776	88,662	82,547	76,432	70,318	64,203	58,089	51,974	45,859	39,745	33,630	27,516	21,401	15,286	9,172	3,057
72,729	66,911	61,558	56,633	52,103	47,934	44,100	40,572	37,326	34,340	31,593	29,065	26,740	24,601	22,633	20,822	19,156	17,624	16,214	14,917
46,505	46,209	45,447	44,257	42,673	40,727	38,447	35,861	32,992	29,863	26,496	22,909	19,119	15,144	10,997	6,693	2,245	(2,337)	(7,042)	(11,860)
13,952	**13,863**	**13,634**	**13,277**	**12,802**	**12,218**	**11,534**	**10,758**	**9,898**	**8,959**	**7,949**	**6,873**	**5,736**	**4,543**	**3,299**	**2,008**	**673**	**(701)**	**(2,113)**	**(3,558)**

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	B.C. 7 LCOE - Fish Lake Dike Upgrade - YUB-YECL-37(a)
Year	2014
# Years	37
Capital Cost ($)	$ 1,720,000
***Et* = Electricity generation in year *t* (kWh)**	8,730,000

O&M	O&M Growth
$ 2,500	2.000%

2015	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	8%

Discount Rate	9.037%
Real Discount	6.899%

t	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Remaining Ratebase	1,720,000	1,696,757	1,650,270	1,603,784	1,557,297	1,510,811	1,464,324	1,417,838	1,371,351	1,324,865	1,278,378	1,231,892	1,185,405	1,138,919	1,092,432	1,045,946	999,459
Return	62,783	123,870	120,476	117,083	113,689	110,295	106,902	103,508	100,114	96,720	93,327	89,933	86,539	83,146	79,752	76,358	72,965
Depreciation	23,243	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486
Income Tax	(5,704)	(10,160)	(7,798)	(5,688)	(3,812)	(2,151)	(687)	595	1,710	2,671	3,491	4,181	4,750	5,210	5,568	5,833	6,012
It* = Investment Expenditures in Year *t	80,323	160,196	159,165	157,881	156,363	154,631	152,701	150,589	148,311	145,878	143,304	140,600	137,776	134,842	131,807	128,678	125,463
Mt* = Operations and Maintenance in Year *t	2,500	2,550	2,601	2,653	2,706	2,760	2,815	2,872	2,929	2,988	3,047	3,108	3,171	3,234	3,299	3,365	3,432
It + Mt	82,823	162,746	161,766	160,534	159,069	157,391	155,516	153,461	151,240	148,866	146,352	143,708	140,947	138,076	135,105	132,043	128,895
(It + Mt) / (1+r)^t	75,958	136,887	124,786	113,571	103,208	93,655	84,870	76,807	69,422	62,669	56,504	50,885	45,771	41,122	36,902	33,077	29,612
Et / (1+r)^t	8,166,575	7,639,513	7,146,467	6,685,241	6,253,783	5,850,170	5,472,606	5,119,410	4,789,009	4,479,931	4,190,801	3,920,331	3,667,317	3,430,632	3,209,223	3,002,103	2,808,350
Levelized Cost of Energy ($/kWh)	**0.012**																

Income Tax Calculation

Undepreciated Capital Cost	1,720,000	1,651,200	1,519,104	1,397,576	1,285,770	1,182,908	1,088,275	1,001,213	921,116	847,427	779,633	717,262	659,881	607,091	558,523	513,842	472,734
Capital Cost Allowance (CCA)	68,800	132,096	121,528	111,806	102,862	94,633	87,062	80,097	73,689	67,794	62,371	57,381	52,790	48,567	44,682	41,107	37,819
Final Undepreciated Capital Cost	**1,651,200**	**1,519,104**	**1,397,576**	**1,285,770**	**1,182,908**	**1,088,275**	**1,001,213**	**921,116**	**847,427**	**779,633**	**717,262**	**659,881**	**607,091**	**558,523**	**513,842**	**472,734**	**434,916**
Taxable Return	49,787	98,228	95,537	92,845	90,154	87,463	84,772	82,081	79,389	76,698	74,007	71,316	68,625	65,934	63,242	60,551	57,860
CCA	68,800	132,096	121,528	111,806	102,862	94,633	87,062	80,097	73,689	67,794	62,371	57,381	52,790	48,567	44,682	41,107	37,819
Taxable Income	(19,013)	(33,868)	(25,992)	(18,961)	(12,707)	(7,170)	(2,290)	1,984	5,700	8,904	11,637	13,935	15,834	17,366	18,561	19,444	20,041
Income Tax Payable	**(5,704)**	**(10,160)**	**(7,798)**	**(5,688)**	**(3,812)**	**(2,151)**	**(687)**	**595**	**1,710**	**2,671**	**3,491**	**4,181**	**4,750**	**5,210**	**5,568**	**5,833**	**6,012**

[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]
2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
952,973	906,486	860,000	813,514	767,027	720,541	674,054	627,568	581,081	534,595	488,108	441,622	395,135	348,649	302,162	255,676	209,189	162,703	116,216	69,730	23,243
69,571	66,177	62,783	59,390	55,996	52,602	49,209	45,815	42,421	39,028	35,634	32,240	28,846	25,453	22,059	18,665	15,272	11,878	8,484	5,091	1,697
46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486	46,486
6,113	6,140	6,101	6,001	5,844	5,634	5,377	5,076	4,735	4,356	3,943	3,498	3,025	2,524	2,000	1,452	884	296	(309)	(930)	(1,566)
122,170	118,804	115,371	111,877	108,326	104,723	101,073	97,378	93,643	89,870	86,063	82,225	78,358	74,464	70,545	66,604	62,642	58,661	54,662	50,647	46,617
3,501	3,571	3,642	3,715	3,789	3,865	3,942	4,021	4,102	4,184	4,267	4,353	4,440	4,528	4,619	4,711	4,806	4,902	5,000	5,100	5,202
125,671	122,375	119,013	115,592	112,115	108,588	105,015	101,399	97,744	94,054	90,331	86,578	82,797	78,992	75,164	71,315	67,447	63,563	59,662	55,747	51,819
26,479	23,647	21,091	18,787	16,712	14,845	13,166	11,659	10,308	9,096	8,012	7,043	6,177	5,405	4,717	4,104	3,560	3,077	2,649	2,270	1,935
2,627,102	2,457,552	2,298,944	2,150,573	2,011,777	1,881,939	1,760,481	1,646,861	1,540,574	1,441,147	1,348,137	1,261,130	1,179,738	1,103,599	1,032,374	965,745	903,417	845,112	790,569	739,546	691,817
434,916	400,122	368,113	338,664	311,570	286,645	263,713	242,616	223,207	205,350	188,922	173,809	159,904	147,112	135,343	124,515	114,554	105,390	96,958	89,202	82,066
34,793	32,010	29,449	27,093	24,926	22,932	21,097	19,409	17,857	16,428	15,114	13,905	12,792	11,769	10,827	9,961	9,164	8,431	7,757	7,136	6,565
400,122	**368,113**	**338,664**	**311,570**	**286,645**	**263,713**	**242,616**	**223,207**	**205,350**	**188,922**	**173,809**	**159,904**	**147,112**	**135,343**	**124,515**	**114,554**	**105,390**	**96,958**	**89,202**	**82,066**	**75,500**
55,169	52,478	49,787	47,095	44,404	41,713	39,022	36,331	33,640	30,948	28,257	25,566	22,875	20,184	17,493	14,801	12,110	9,419	6,728	4,037	1,346
34,793	32,010	29,449	27,093	24,926	22,932	21,097	19,409	17,857	16,428	15,114	13,905	12,792	11,769	10,827	9,961	9,164	8,431	7,757	7,136	6,565
20,376	20,468	20,338	20,002	19,479	18,782	17,925	16,921	15,783	14,520	13,143	11,661	10,083	8,415	6,665	4,840	2,946	988	(1,029)	(3,099)	(5,220)
6,113	**6,140**	**6,101**	**6,001**	**5,844**	**5,634**	**5,377**	**5,076**	**4,735**	**4,356**	**3,943**	**3,498**	**3,025**	**2,524**	**2,000**	**1,452**	**884**	**296**	**(309)**	**(930)**	**(1,566)**

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	B.C. 9 LCOE - Ditch #3 Diversion Structure - YUB-YECL-37(a)
Year	2014
# Years	37
Capital Cost ($)	$ 1,640,000
***Et* = Electricity generation in year *t* (kWh)**	8,730,000

O&M	O&M Growth
$ 2,500	2.000%

2014	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	8%

Discount Rate	9.037%
Real Discount	6.899%

t	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]
Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Remaining Ratebase	1,640,000	1,617,838	1,573,514	1,529,189	1,484,865	1,440,541	1,396,216	1,351,892	1,307,568	1,263,243	1,218,919	1,174,595	1,130,270	1,085,946	1,041,622	997,297	952,973
Return	59,863	118,109	114,873	111,637	108,401	105,165	101,929	98,694	95,458	92,222	88,986	85,750	82,514	79,278	76,043	72,807	69,571
Depreciation	22,162	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324
Income Tax	(5,439)	(9,688)	(7,435)	(5,424)	(3,635)	(2,051)	(655)	567	1,631	2,547	3,329	3,986	4,529	4,968	5,309	5,562	5,733
It* = Investment Expenditures in Year *t	76,587	152,745	151,762	150,538	149,090	147,439	145,599	143,585	141,413	139,093	136,639	134,060	131,368	128,570	125,676	122,693	119,628
Mt* = Operations and Maintenance in Year *t	2,500	2,550	2,601	2,653	2,706	2,760	2,815	2,872	2,929	2,988	3,047	3,108	3,171	3,234	3,299	3,365	3,432
It + Mt	79,087	155,295	154,363	153,191	151,797	150,199	148,414	146,457	144,342	142,081	139,686	137,169	134,539	131,804	128,975	126,058	123,060
(It + Mt) / (1+r)^t	72,532	130,620	119,075	108,376	98,489	89,376	80,994	73,302	66,255	59,812	53,931	48,569	43,690	39,254	35,228	31,577	28,272
Et / (1+r)^t	8,166,575	7,639,513	7,146,467	6,685,241	6,253,783	5,850,170	5,472,606	5,119,410	4,789,009	4,479,931	4,190,801	3,920,331	3,667,317	3,430,632	3,209,223	3,002,103	2,808,350
Levelized Cost of Energy ($/kWh)	**0.012**																

Income Tax Calculation

Undepreciated Capital Cost	1,640,000	1,574,400	1,448,448	1,332,572	1,225,966	1,127,889	1,037,658	954,645	878,274	808,012	743,371	683,901	629,189	578,854	532,546	489,942	450,747
Capital Cost Allowance (CCA)	65,600	125,952	115,876	106,606	98,077	90,231	83,013	76,372	70,262	64,641	59,470	54,712	50,335	46,308	42,604	39,195	36,060
Final Undepreciated Capital Cost	**1,574,400**	**1,448,448**	**1,332,572**	**1,225,966**	**1,127,889**	**1,037,658**	**954,645**	**878,274**	**808,012**	**743,371**	**683,901**	**629,189**	**578,854**	**532,546**	**489,942**	**450,747**	**414,687**
Taxable Return	47,471	93,659	91,093	88,527	85,961	83,395	80,829	78,263	75,697	73,131	70,565	67,999	65,433	62,867	60,301	57,735	55,169
CCA	65,600	125,952	115,876	106,606	98,077	90,231	83,013	76,372	70,262	64,641	59,470	54,712	50,335	46,308	42,604	39,195	36,060
Taxable Income	(18,129)	(32,293)	(24,783)	(18,079)	(12,116)	(6,836)	(2,184)	1,891	5,435	8,490	11,095	13,287	15,098	16,559	17,697	18,540	19,109
Income Tax Payable	**(5,439)**	**(9,688)**	**(7,435)**	**(5,424)**	**(3,635)**	**(2,051)**	**(655)**	**567**	**1,631**	**2,547**	**3,329**	**3,986**	**4,529**	**4,968**	**5,309**	**5,562**	**5,733**

[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]
2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
908,649	864,324	820,000	775,676	731,351	687,027	642,703	598,378	554,054	509,730	465,405	421,081	376,757	332,432	288,108	243,784	199,459	155,135	110,811	66,486	22,162
66,335	63,099	59,863	56,627	53,392	50,156	46,920	43,684	40,448	37,212	33,976	30,741	27,505	24,269	21,033	17,797	14,561	11,325	8,090	4,854	1,618
44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324	44,324
5,828	5,855	5,818	5,722	5,572	5,372	5,127	4,840	4,515	4,154	3,760	3,336	2,884	2,407	1,907	1,385	843	283	(294)	(887)	(1,493)
116,488	113,278	110,005	106,673	103,288	99,852	96,372	92,849	89,287	85,690	82,060	78,401	74,713	71,000	67,264	63,506	59,728	55,932	52,120	48,292	44,449
3,501	3,571	3,642	3,715	3,789	3,865	3,942	4,021	4,102	4,184	4,267	4,353	4,440	4,528	4,619	4,711	4,806	4,902	5,000	5,100	5,202
119,988	116,849	113,647	110,388	107,077	103,717	100,314	96,870	93,389	89,874	86,328	82,753	79,153	75,529	71,883	68,217	64,534	60,834	57,119	53,391	49,651
25,281	22,579	20,140	17,942	15,961	14,179	12,577	11,138	9,848	8,692	7,657	6,732	5,905	5,168	4,511	3,926	3,406	2,945	2,536	2,174	1,854
2,627,102	2,457,552	2,298,944	2,150,573	2,011,777	1,881,939	1,760,481	1,646,861	1,540,574	1,441,147	1,348,137	1,261,130	1,179,738	1,103,599	1,032,374	965,745	903,417	845,112	790,569	739,546	691,817
414,687	381,512	350,991	322,912	297,079	273,312	251,447	231,332	212,825	195,799	180,135	165,724	152,466	140,269	129,048	118,724	109,226	100,488	92,449	85,053	78,249
33,175	30,521	28,079	25,833	23,766	21,865	20,116	18,507	17,026	15,664	14,411	13,258	12,197	11,222	10,324	9,498	8,738	8,039	7,396	6,804	6,260
381,512	**350,991**	**322,912**	**297,079**	**273,312**	**251,447**	**231,332**	**212,825**	**195,799**	**180,135**	**165,724**	**152,466**	**140,269**	**129,048**	**118,724**	**109,226**	**100,488**	**92,449**	**85,053**	**78,249**	**71,989**
52,603	50,037	47,471	44,905	42,339	39,773	37,207	34,641	32,075	29,509	26,943	24,377	21,811	19,245	16,679	14,113	11,547	8,981	6,415	3,849	1,283
33,175	30,521	28,079	25,833	23,766	21,865	20,116	18,507	17,026	15,664	14,411	13,258	12,197	11,222	10,324	9,498	8,738	8,039	7,396	6,804	6,260
19,428	19,516	19,392	19,072	18,573	17,908	17,091	16,134	15,049	13,845	12,532	11,119	9,614	8,023	6,355	4,615	2,809	942	(981)	(2,955)	(4,977)
5,828	**5,855**	**5,818**	**5,722**	**5,572**	**5,372**	**5,127**	**4,840**	**4,515**	**4,154**	**3,760**	**3,336**	**2,884**	**2,407**	**1,907**	**1,385**	**843**	**283**	**(294)**	**(887)**	**(1,493)**

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	B.C. 28 LCOE - Water License Renewal - YUB-YECL-37(a)
Year	2013
# Years	25
Capital Cost ($)	$ 1,829,000
***Et* = Electricity generation in year *t* (kWh)**	8,730,000

O&M	O&M Growth
$ 119,000	2.000%

2013	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	100%

Discount Rate	9.037%
Real Discount	6.899%

t	**[1]**	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**	**[11]**	**[12]**
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Remaining Ratebase	1,829,000	1,792,420	1,719,260	1,646,100	1,572,940	1,499,780	1,426,620	1,353,460	1,280,300	1,207,140	1,133,980	1,060,820
Return	66,762	130,854	125,513	120,172	114,831	109,490	104,149	98,808	93,467	88,126	82,785	77,444
Depreciation	36,580	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160
Income Tax	(258,467)	(243,220)	29,859	28,589	27,318	26,047	24,777	23,506	22,236	20,965	19,694	18,424
It* = Investment Expenditures in Year *t	(155,125)	(39,206)	228,532	221,920	215,309	208,697	202,086	195,474	188,863	182,251	175,639	169,028
Mt* = Operations and Maintenance in Year *t	119,000	121,380	123,808	126,284	128,809	131,386	134,013	136,694	139,427	142,216	145,060	147,962
It + Mt	(36,125)	82,174	352,340	348,204	344,118	340,083	336,099	332,168	328,290	324,467	320,700	316,989
(It + Mt) / (1+r)^t	(33,131)	69,117	271,793	246,341	223,273	202,366	183,420	166,250	150,691	136,592	123,817	112,241
Et / (1+r)^t	8,166,575	7,639,513	7,146,467	6,685,241	6,253,783	5,850,170	5,472,606	5,119,410	4,789,009	4,479,931	4,190,801	3,920,331

Levelized Cost of Energy ($/kWh) **0.026**

Income Tax Calculation

Undepreciated Capital Cost	1,829,000	914,500	-	-	-	-	-	-	-	-	-	-
Capital Cost Allowance (CCA)	914,500	914,500	-	-	-	-	-	-	-	-	-	-
Final Undepreciated Capital Cost	**914,500**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Taxable Return	52,942	103,766	99,530	95,295	91,060	86,824	82,589	78,354	74,118	69,883	65,648	61,412
CCA	914,500	914,500	-	-	-	-	-	-	-	-	-	-
Taxable Income	(861,558)	(810,734)	99,530	95,295	91,060	86,824	82,589	78,354	74,118	69,883	65,648	61,412
Income Tax Payable	**(258,467)**	**(243,220)**	**29,859**	**28,589**	**27,318**	**26,047**	**24,777**	**23,506**	**22,236**	**20,965**	**19,694**	**18,424**

[13] 2025	**[14]** 2026	**[15]** 2027	**[16]** 2028	**[17]** 2029	**[18]** 2030	**[19]** 2031	**[20]** 2032	**[21]** 2033	**[22]** 2034	**[23]** 2035	**[24]** 2036	**[25]** 2037
987,660	914,500	841,340	768,180	695,020	621,860	548,700	475,540	402,380	329,220	256,060	182,900	109,740
72,103	66,762	61,421	56,080	50,739	45,398	40,057	34,716	29,375	24,034	18,693	13,352	8,011
73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160	73,160
17,153	15,883	14,612	13,341	12,071	10,800	9,530	8,259	6,988	5,718	4,447	3,177	1,906
162,416	155,805	149,193	142,582	135,970	129,358	122,747	116,135	109,524	102,912	96,301	89,689	83,077
150,921	153,939	157,018	160,158	163,361	166,629	169,961	173,361	176,828	180,364	183,972	187,651	191,404
313,337	309,744	306,211	302,740	299,331	295,987	292,708	289,496	286,351	283,276	280,272	277,340	274,481
101,752	92,249	83,638	75,836	68,768	62,364	56,561	51,304	46,541	42,225	38,315	34,772	31,561
3,667,317	3,430,632	3,209,223	3,002,103	2,808,350	2,627,102	2,457,552	2,298,944	2,150,573	2,011,777	1,881,939	1,760,481	1,646,861
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
57,177	52,942	48,706	44,471	40,236	36,000	31,765	27,530	23,294	19,059	14,824	10,588	6,353
-	-	-	-	-	-	-	-	-	-	-	-	-
57,177	52,942	48,706	44,471	40,236	36,000	31,765	27,530	23,294	19,059	14,824	10,588	6,353
17,153	**15,883**	**14,612**	**13,341**	**12,071**	**10,800**	**9,530**	**8,259**	**6,988**	**5,718**	**4,447**	**3,177**	**1,906**

Yukon Electrical Levelized Cost of Energy at Fish Lake

Project Detail	All Cases Considered - Fish Lake Facility - YUB-YECL-37(b)
Year	2013
# Years	38
Capital Cost ($)	$ 9,653,000
***Et* = Electricity generation in year*t* (kWh)**	8,730,000

O&M (2015)	O&M Growth
$ 445,500	2.000%

2013	Rate	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56.00%	3.248%	3.248%
Preferred	0.000%	0.00%	0.000%	0.000%
Common	9.210%	44.00%	5.789%	4.052%
			9.037%	7.300%

Tax Rate	30%
CCA	8%

Discount Rate	9.037%
Real Discount	6.899%

t	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ratebase	9,653,000	9,525,987	9,271,961	9,017,934	8,763,908	8,509,882	8,255,855	8,001,829	7,747,803	7,493,776	7,239,750	6,985,724	6,731,697	6,477,671	6,223,645	5,969,618	5,715,592	5,461,566
Return	352,354	695,435	676,890	658,345	639,800	621,255	602,710	584,166	565,621	547,076	528,531	509,986	491,441	472,896	454,351	435,806	417,261	398,716
Depreciation	127,013	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026
Income Tax	(32,012)	(56,963)	(43,583)	(31,625)	(20,978)	(11,535)	(3,200)	4,115	10,491	16,005	20,725	24,714	28,031	30,730	32,859	34,466	35,591	36,273
It* = Investment Expenditures in Yea*t	447,355	892,498	887,334	880,746	872,849	863,747	853,537	842,307	830,138	817,107	803,282	788,726	773,498	757,652	741,237	724,298	706,879	689,016
Mt* = Operations and Maintenance in Year*t	368,000	408,500	445,500	454,410	463,498	472,768	482,224	491,868	501,705	511,739	521,974	532,414	543,062	553,923	565,002	576,302	587,828	599,584
It + Mt	815,355	1,300,998	1,332,834	1,335,156	1,336,347	1,336,515	1,335,760	1,334,175	1,331,844	1,328,847	1,325,256	1,321,140	1,316,560	1,311,575	1,306,238	1,300,600	1,294,706	1,288,600
(It + Mt) / (1+r)^t	747,777	1,094,278	1,028,141	944,570	867,056	795,293	728,966	667,755	611,340	559,410	511,659	467,795	427,536	390,617	356,784	325,801	297,444	271,505
Et / (1+r)^t	8,166,575	7,639,513	7,146,467	6,685,241	6,253,783	5,850,170	5,472,606	5,119,410	4,789,009	4,479,931	4,190,801	3,920,331	3,667,317	3,430,632	3,209,223	3,002,103	2,808,350	2,627,102
Levelized Cost of Energy ($/kWh)	**0.115**																	

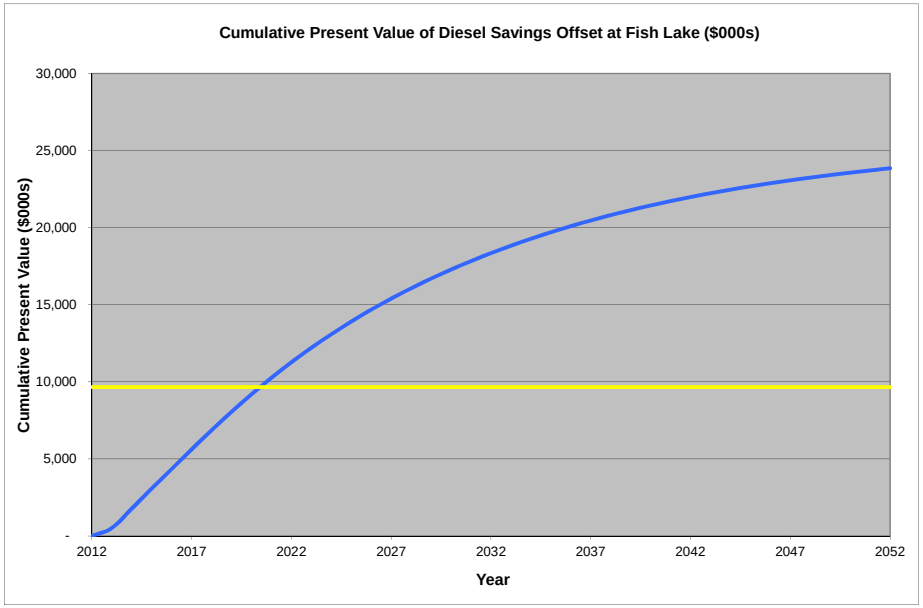
Income Tax Calculation

Undepreciated Capital Cost	9,653,000	9,266,880	8,525,530	7,843,487	7,216,008	6,638,728	6,107,629	5,619,019	5,169,498	4,755,938	4,375,463	4,025,426	3,703,392	3,407,120	3,134,551	2,883,787	2,653,084	2,440,837
Capital Cost Allowance (CCA)	386,120	741,350	682,042	627,479	577,281	531,098	488,610	449,522	413,560	380,475	350,037	322,034	296,271	272,570	250,764	230,703	212,247	195,267
Final Undepreciated Capital Cost	**9,266,880**	**8,525,530**	**7,843,487**	**7,216,008**	**6,638,728**	**6,107,629**	**5,619,019**	**5,169,498**	**4,755,938**	**4,375,463**	**4,025,426**	**3,703,392**	**3,407,120**	**3,134,551**	**2,883,787**	**2,653,084**	**2,440,837**	**2,245,570**
Taxable Return	279,413	551,473	536,767	522,061	507,355	492,649	477,943	463,237	448,531	433,825	419,119	404,414	389,708	375,002	360,296	345,590	330,884	316,178
CCA	386,120	741,350	682,042	627,479	577,281	531,098	488,610	449,522	413,560	380,475	350,037	322,034	296,271	272,570	250,764	230,703	212,247	195,267
Taxable Income	(106,707)	(189,877)	(145,275)	(105,418)	(69,926)	(38,449)	(10,667)	13,716	34,972	53,350	69,082	82,379	93,436	102,432	109,532	114,887	118,637	120,911
Income Tax Payable	**(32,012)**	**(56,963)**	**(43,583)**	**(31,625)**	**(20,978)**	**(11,535)**	**(3,200)**	**4,115**	**10,491**	**16,005**	**20,725**	**24,714**	**28,031**	**30,730**	**32,859**	**34,466**	**35,591**	**36,273**

[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]
2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
5,207,539	4,953,513	4,699,487	4,445,461	4,191,434	3,937,408	3,683,382	3,429,355	3,175,329	2,921,303	2,667,276	2,413,250	2,159,224	1,905,197	1,651,171	1,397,145	1,143,118	889,092	635,066	381,039	127,013
380,171	361,626	343,081	324,536	305,991	287,447	268,902	250,357	231,812	213,267	194,722	176,177	157,632	139,087	120,542	101,997	83,452	64,907	46,362	27,817	9,272
254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026	254,026
36,548	36,448	36,002	35,240	34,185	32,862	31,292	29,495	27,488	25,289	22,913	20,374	17,685	14,859	11,905	8,835	5,658	2,382	(985)	(4,436)	(7,963)
670,745	652,100	633,110	613,803	594,203	574,335	554,220	533,878	513,326	492,582	471,661	450,577	429,344	407,972	386,474	364,859	343,136	321,315	299,403	277,408	255,335
611,576	623,808	636,284	649,009	661,990	675,229	688,734	702,509	716,559	730,890	745,508	760,418	775,626	791,139	806,962	823,101	839,563	856,354	873,481	890,951	908,770
1,282,321	1,275,908	1,269,394	1,262,812	1,256,193	1,249,565	1,242,954	1,236,386	1,229,885	1,223,472	1,217,169	1,210,995	1,204,970	1,199,111	1,193,435	1,187,959	1,182,699	1,177,669	1,172,884	1,168,359	1,164,105
247,789	226,115	206,316	188,235	171,729	156,665	142,920	130,382	118,947	108,520	99,013	90,346	82,446	75,245	68,682	62,700	57,249	52,281	47,753	43,626	39,865
2,457,552	2,298,944	2,150,573	2,011,777	1,881,939	1,760,481	1,646,861	1,540,574	1,441,147	1,348,137	1,261,130	1,179,738	1,103,599	1,032,374	965,745	903,417	845,112	790,569	739,546	691,817	647,168
2,245,570	2,065,924	1,900,650	1,748,598	1,608,711	1,480,014	1,361,613	1,252,684	1,152,469	1,060,271	975,450	897,414	825,621	759,571	698,805	642,901	591,469	544,151	500,619	460,570	423,724
179,646	165,274	152,052	139,888	128,697	118,401	108,929	100,215	92,198	84,822	78,036	71,793	66,050	60,766	55,904	51,432	47,318	43,532	40,050	36,846	33,898
2,065,924	**1,900,650**	**1,748,598**	**1,608,711**	**1,480,014**	**1,361,613**	**1,252,684**	**1,152,469**	**1,060,271**	**975,450**	**897,414**	**825,621**	**759,571**	**698,805**	**642,901**	**591,469**	**544,151**	**500,619**	**460,570**	**423,724**	**389,826**
301,472	286,766	272,060	257,354	242,648	227,942	213,236	198,530	183,824	169,118	154,412	139,706	125,001	110,295	95,589	80,883	66,177	51,471	36,765	22,059	7,353
179,646	165,274	152,052	139,888	128,697	118,401	108,929	100,215	92,198	84,822	78,036	71,793	66,050	60,766	55,904	51,432	47,318	43,532	40,050	36,846	33,898
121,826	121,492	120,008	117,466	113,951	109,541	104,307	98,316	91,627	84,297	76,376	67,913	58,951	49,529	39,684	29,451	18,859	7,939	(3,285)	(14,787)	(26,545)
36,548	**36,448**	**36,002**	**35,240**	**34,185**	**32,862**	**31,292**	**29,495**	**27,488**	**25,289**	**22,913**	**20,374**	**17,685**	**14,859**	**11,905**	**8,835**	**5,658**	**2,382**	**(985)**	**(4,436)**	**(7,963)**

Table Reproduced from Table 4.1-2 from Yukon Energy Corporation 2012/2013 General Rate Application Compliance Filing, Attachment 4.1

Line Number	Grid Load	Hydro Generation	Diesel Generation	Increase in Load	Increase in Diesel	Incremental Diesel per Incremental Load
	[1]	[2]	[3]	[4]	[5]	[6]
[1]	400	394.9	5.1			32%
[2]	405	398.3	6.7	5	1.6	36%
[3]	410	401.5	8.5	5	1.8	40%
[4]	415	404.5	10.5	5	2.0	44%
[5]	420	407.3	12.7	5	2.2	48%
[6]	425	409.9	15.1	5	2.4	52%
[7]	430	412.3	17.7	5	2.6	54%
[8]	435	414.6	20.4	5	2.7	58%
[9]	440	416.7	23.3	5	2.9	60%
[10]	445	418.7	26.3	5	3.0	64%
[11]	450	420.5	29.5	5	3.2	66%
[12]	455	422.2	32.8	5	3.3	66%
[13]	460	423.9	36.1	5	3.3	70%
[14]	465	425.4	39.6	5	3.5	72%
[15]	470	426.8	43.2	5	3.6	74%
[16]	475	428.1	46.9	5	3.7	74%
[17]	480	429.4	50.6	5	3.7	76%
[18]	485	430.6	54.4	5	3.8	76%
[19]	490	431.8	58.2	5	3.8	78%
[20]	495	432.9	62.1	5	3.9	78%
[21]	500	434.0	66.0	5	3.9	78%



Discount Rate	9.037%
Grid Escalation Rate	2%
Price of Diesel Generation (c/kWh)	28.71
Price of Diesel Escalation Rate	2%
Fish Lake 1 Production (GWh)	5.64
Fish Lake 2 Production (GWh)	3.09
TOTAL Fish Lake Production (GWh)	8.73
Incremental Diesel per Incremental Load (beyond 500GWh Grid Load)	78%
Cost of Project	$ 9,653,000

Without Fish Lake

	2012	[1] 2013	[2] 2014	[3] 2015	[4] 2016	[5] 2017	[6] 2018	[7] 2019	[8] 2020	[9] 2021	[10] 2022	[11] 2023	[12] 2024	[13] 2025	[14] 2026	[15] 2027	[16] 2028	[17] 2029	[18] 2030
Grid Load	425.0	433.5	442.2	451.0	460.0	469.2	478.6	488.2	498.0	507.9	518.1	528.4	539.0	549.8	560.8	572.0	583.4	595.1	607.0
Hydro	409.9	413.9	417.6	420.8	423.9	426.6	429.0	431.4	433.6	435.7	438.0	440.3	442.6	445.0	447.4	449.8	452.4	454.9	457.5
Diesel	15.10	19.59	24.60	30.17	36.12	42.65	49.58	56.83	64.41	72.17	80.10	88.18	96.42	104.83	113.41	122.16	131.08	140.18	149.46

With Fish Lake

	2012	[1] 2013	[2] 2014	[3] 2015	[4] 2016	[5] 2017	[6] 2018	[7] 2019	[8] 2020	[9] 2021	[10] 2022	[11] 2023	[12] 2024	[13] 2025	[14] 2026	[15] 2027	[16] 2028	[17] 2029	[18] 2030
Grid Load	425.0	429.9	433.4	442.3	451.3	460.5	469.9	479.5	489.2	499.2	509.3	519.7	530.3	541.1	552.0	563.3	574.7	586.4	598.3
Hydro	409.9	412.3	413.9	417.6	420.9	424.1	426.8	429.3	431.6	433.8	436.1	438.3	440.7	443.0	445.5	447.9	450.4	453.0	455.6
Diesel	15.10	17.67	19.56	24.67	30.36	36.45	43.12	50.20	57.61	65.36	73.29	81.37	89.61	98.02	106.60	115.35	124.27	133.37	142.65

Diesel Savings

	2012	[1] 2013	[2] 2014	[3] 2015	[4] 2016	[5] 2017	[6] 2018	[7] 2019	[8] 2020	[9] 2021	[10] 2022	[11] 2023	[12] 2024	[13] 2025	[14] 2026	[15] 2027	[16] 2028	[17] 2029	[18] 2030
Diesel Variance		1.92	5.04	5.50	5.76	6.20	6.46	6.62	6.79	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81
Price of Diesel (c/kWh)	28.71	29.28	29.87	30.47	31.08	31.70	32.33	32.98	33.64	34.31	35.00	35.70	36.41	37.14	37.88	38.64	39.41	40.20	41.00
Diesel Savings ($000s)		562	1,507	1,675	1,791	1,964	2,088	2,185	2,285	2,336	2,383	2,431	2,479	2,529	2,580	2,631	2,684	2,737	2,792
Present Value ($000s)		516	1,267	1,292	1,267	1,274	1,242	1,192	1,144	1,072	1,003	938	878	821	768	719	672	629	588
Cumulative Present Value ($000s)	-	516	1,783	3,075	4,343	5,617	6,859	8,051	9,195	10,268	11,271	12,209	13,087	13,909	14,677	15,395	16,068	16,697	17,285

NPV of Diesel ($000s) **23,847**

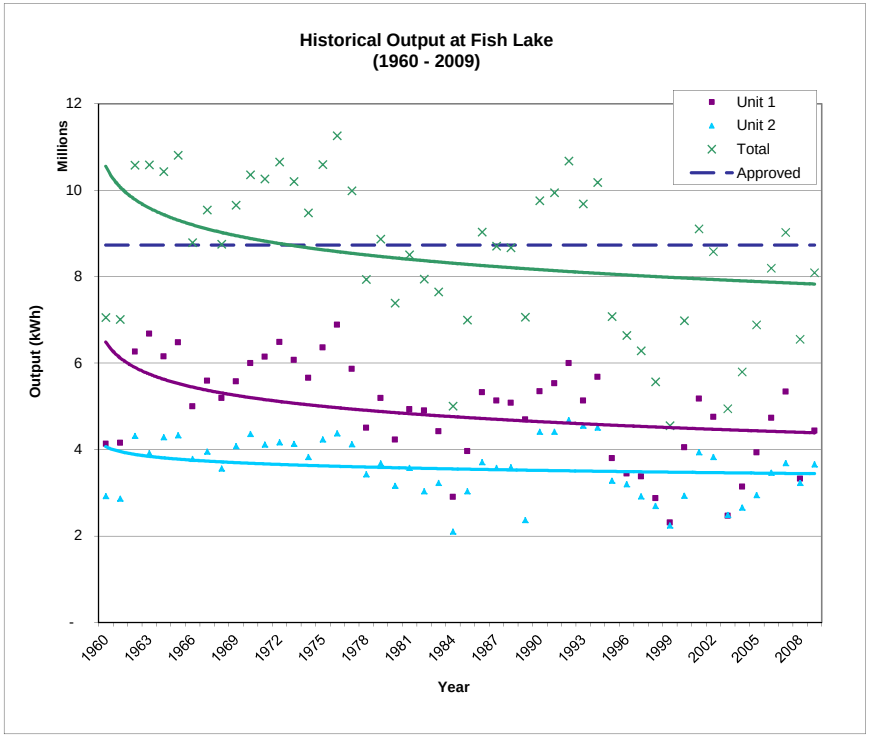
[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]
2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
619.1	631.5	644.2	657.0	670.2	683.6	697.3	711.2	725.4	739.9	754.7	769.8	785.2	800.9	816.9	833.3	850.0	867.0	884.3	902.0	920.0	938.4
460.2	462.9	465.7	468.5	471.4	474.4	477.4	480.5	483.6	486.8	490.0	493.4	496.7	500.2	503.7	507.3	511.0	514.7	518.5	522.4	526.4	530.5
158.93	168.59	178.44	188.49	198.74	209.20	219.86	230.74	241.83	253.15	264.69	276.47	288.48	300.73	313.22	325.96	338.96	352.22	365.75	379.54	393.61	407.97

[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]
2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
610.4	622.8	635.4	648.3	661.5	674.9	688.5	702.5	716.7	731.2	746.0	761.1	776.5	792.2	808.2	824.6	841.2	858.2	875.6	893.2	911.3	929.7
458.3	461.0	463.8	466.6	469.5	472.5	475.5	478.5	481.7	484.9	488.1	491.4	494.8	498.3	501.8	505.4	509.1	512.8	516.6	520.5	524.5	528.5
152.12	161.78	171.63	181.68	191.93	202.39	213.05	223.93	235.02	246.34	257.88	269.66	281.67	293.92	306.41	319.15	332.15	345.41	358.94	372.73	386.80	401.16

[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]
2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81	6.81
41.83	42.66	43.51	44.39	45.27	46.18	47.10	48.04	49.00	49.98	50.98	52.00	53.04	54.11	55.19	56.29	57.42	58.57	59.74	60.93	62.15	63.39
2,848	2,905	2,963	3,022	3,083	3,144	3,207	3,271	3,337	3,404	3,472	3,541	3,612	3,684	3,758	3,833	3,910	3,988	4,068	4,149	4,232	4,317
550	515	482	451	421	394	369	345	323	302	282	264	247	231	216	202	189	177	166	155	145	136
17,835	18,350	18,832	19,282	19,704	20,098	20,467	20,812	21,134	21,436	21,719	21,983	22,230	22,461	22,678	22,880	23,069	23,246	23,412	23,567	23,712	23,847

Yukon Electrical
Historical Output at Fish Lake
YUB-YECL-37(d)

	Output (kWh)		
Year	Unit 1	Unit 2	Total
1960	4,130,766	2,925,460	7,056,226
1961	4,150,941	2,862,039	7,012,980
1962	6,261,617	4,318,357	10,579,974
1963	6,673,603	3,914,799	10,588,402
1964	6,150,116	4,283,120	10,433,236
1965	6,480,248	4,326,902	10,807,150
1966	4,999,689	3,785,137	8,784,826
1967	5,585,468	3,953,158	9,538,626
1968	5,187,803	3,560,621	8,748,424
1969	5,576,523	4,079,263	9,655,786
1970	5,996,483	4,356,253	10,352,736
1971	6,143,513	4,113,452	10,256,965
1972	6,487,327	4,167,587	10,654,914
1973	6,068,456	4,133,998	10,202,454
1974	5,652,224	3,824,746	9,476,970
1975	6,359,728	4,232,994	10,592,722
1976	6,887,128	4,374,738	11,261,866
1977	5,862,350	4,122,752	9,985,102
1978	4,503,992	3,430,062	7,934,054
1979	5,189,768	3,680,100	8,869,868
1980	4,227,040	3,157,240	7,384,280
1981	4,932,344	3,575,889	8,508,233
1982	4,903,380	3,038,061	7,941,441
1983	4,420,000	3,225,768	7,645,768
1984	2,903,520	2,101,808	5,005,328
1985	3,962,040	3,031,893	6,993,933
1986	5,323,920	3,707,167	9,031,087
1987	5,128,800	3,574,200	8,703,000
1988	5,076,920	3,591,650	8,668,570
1989	4,694,040	2,369,600	7,063,640
1990	5,341,200	4,412,310	9,753,510
1991	5,526,770	4,413,530	9,940,300
1992	5,995,200	4,678,030	10,673,230
1993	5,131,800	4,550,220	9,682,020
1994	5,676,252	4,505,168	10,181,420
1995	3,795,492	3,281,247	7,076,739
1996	3,442,176	3,198,605	6,640,781
1997	3,372,960	2,913,520	6,286,480
1998	2,870,400	2,692,830	5,563,230
1999	2,305,680	2,246,040	4,551,720
2000	4,046,400	2,932,200	6,978,600
2001	5,171,640	3,936,960	9,108,600
2002	4,750,200	3,826,080	8,576,280
2003	2,462,400	2,485,560	4,947,960
2004	3,138,840	2,660,520	5,799,360
2005	3,933,000	2,948,160	6,881,160
2006	4,728,480	3,464,640	8,193,120
2007	5,336,880	3,688,320	9,025,200
2008	3,327,120	3,224,040	6,551,160
2009	4,433,280	3,660,360	8,093,640
2010	1,020,480	2,367,240	3,387,720
2011	-	3,638,040	3,638,040
2012	-	3,387,960	3,387,960



	Output (kWh)		
Decade-Long Averages	**Unit 1**	**Unit 2**	**Total**
10-year (1960 - 1969)	5,519,677	3,800,886	9,320,563
10-year (1970 - 1979)	5,915,097	4,043,668	9,958,765
10-year (1980 - 1989)	4,557,200	3,137,328	7,694,528
10-year (1990 - 1999)	4,345,793	3,689,150	8,034,943
10-year (2000 - 2009)	4,132,824	3,282,684	7,415,508
Multi-decade Averages			
50-year (1960 - 2009)	4,894,118	3,590,743	8,484,861
40-year (1970 - 2009)	4,737,729	3,538,207	8,275,936
30-year (1980 - 2009)	4,345,272	3,369,721	7,714,993
20-year (1990 - 2009)	4,239,309	3,485,917	7,725,226
10-year (2000 - 2009)	4,132,824	3,282,684	7,415,508

YUB-YECL-38

Reference: Watson Lake Unit #4 Replacement, YECL Application, Business Case #3, pages 2 and 4

Yukon Electrical is planning to replace Unit #4 (CUL 258), which is at the end of its life, with a new diesel generator. Based on forecast load growth and Yukon Electrical's planning criteria, the new unit is planned to have similar generating capacity in comparison to the existing unit.

*End of Life Condition: CUL 258 [1,500 KW] was manufactured in 1985 and currently has **140,226** operational hours… [emphasis added]*

…

- *Available plant floor space in the existing unit position is not sufficient to allow for a larger unit;*
- *Maintaining the same output capacity allows Yukon Electrical to continue use of existing electrical equipment;*

Request:

(a) Are any of the other units in the Watson Lake plant approaching their end of life? What are the ages and operating hours (end-of-life conditions) of the other units in the Watson Lake generating plant?

(b) Given that Watson Lake Unit #4 is planned to be replaced, is there still a requirement to replace the muffler, heat exchanger and radiator as the replacement unit is the same size as the existing unit? Please explain.

Response:

(a) Yes. Based on forecast running hours, Watson Lake Unit #2 (CUL 257) is approaching the end of its life and is scheduled for replacement in 2015. The replacement of this unit is included in the 2015 capital expenditures in the Application (page 9-61 and Business Case #13).

The ages and operating hours of the units in the Watson Lake generating plant are as follows:

Unit #	Engine Year of Manufacture	Engine Hours (December 2012)	Expected Retirement Year
1	1998	57,579	2022
2	1985	84,524	2015
3	1991	70,868	2021
4	1985	140,226	2013
5	1993	8,339	2023+
6	1998	64,820	2019

(b) Yes, there is a requirement to replace the associated equipment as the existing muffler, heat exchanger, and radiator are the same vintage as the generator unit (1985) and they are specific to the operation of a 900 RPM 3606 Caterpillar engine (existing unit). The new unit is a 1200 RPM 3516 Caterpillar. The cost of this associated equipment has been included in the total forecast project cost of $1,474,000 included in Business Case #3.

YUB-YECL-39

Reference: Business Case #13, Watson Lake Unit #2 Replacement, YECL Application, Business Case #13, Pages 2 and 4

Yukon Electrical is scheduled to replace Unit #2 (CUL 257) [800 kW], which is at the end of its life, with a new diesel generator. Primary drivers for this replacement are: unit age (1985), poor condition of the alternating current (AC) generator, total operating hours and community loading. ***The replacement unit is to have a larger generating capacity in comparison to the existing unit to handle load growth and contingency concerns.*** *[emphasis added]*

…

End of Life Condition: The AC generator on the engine is 1974 vintage and was installed on CUL 257 with 51,404 operational hours from a previous unit in Watson Lake (CUL 192). As of January 1, 2013, CUL 257) [800 kW] had 84,524 operational hours which would put the total hours on the AC generator at ***135,928*** *hours. This generator failed in 2011 and was sent out for repair. [emphasis added]*

…

Alternative #3: Replace ***CUL 258*** *with a new larger size unit. This option addresses the end of life replacement of CUL 257 and the need for additional capacity in the Watson Lake facility. [emphasis added]*

Recommendation:
Proceed with replacement ***of CUL 257 with a unit of similar size and generating capacity to continue to meet the community's load and avoid further costs in respect of this unit, which will be at the end of its life****. [emphasis added]*

Request:

(a) With respect to the Watson Lake Unit #4 replacement, YECL submitted that "in 2012 a peak of 3,126kW was recorded". However, with regard to this business case, YECL submits that the "Watson Lake plant had a recent peak of 3,205kW recorded for the community." Please explain the reasons for ascribing the community of Watson Lake with the different peak loads.

(b) Please provide information as to how often and when major and minor overhauls are performed on units such as CUL 257.

(c) When YECL states that CUL 257 is to be replaced with a similarly sized unit or a larger sized unit, is YECL referring to the unit's generating capacity or physical size?

(d) With respect to replacing the unit, alternative #3 speaks of replacing CUL 258 with a new larger sized unit to address the end-of-life replacement of CUL 257. Should CUL 258 read CUL 257? Please explain.

(e) This business case recommends the replacement of a unit to meet the need for additional capacity in the Watson Lake facility. However, the recommendation is to proceed with the replacement of unit CUL 257 with a unit of similar size and generating capacity to continue to meet the community's load. Please clarify what size of unit is to replace CUL 257.

(f) Please provide a listing by unit of unit capacity, operating hours and utilization factor for 2011 and 2012. Please provide this information for all plant locations.

(g) Will the replacement of the Watson Lake Unit #2 be by a diesel or natural gas unit?

Response:

(a) The recorded values correspond with annual recorded peaks loads. In 2012, a peak of 3,126kW was recorded; in 2011 a peak of 3,205 kW was recorded.

(b) Major and minor overhauls are carried out as per the manufacturer's recommendation. For 1200 RPM 3500 series Caterpillar engines, minor overhauls are completed at 12,000, 36,000, 60,000 and 84,000 hours. Major overhauls are completed at 24,000, 48,000 and 72,000 hours.

(c) Yukon Electrical is referring to generating capacity.

(d) Correct. Alternative #3 should be worded as replace CUL 257.

(e) The estimate of the project cost is based on replacing with a similar sized unit of 800kW. Yukon Electrical will evaluate the load of the community, both peak and annual load duration curves, and select the most suitably sized unit to provide efficient power to the community. If load continues to grow, a larger unit will be evaluated.

(f)

CUL #	Location	Unit #	Rating (kW)	Hours In 2011	Utilization Factor	Hours In 2012	Utilization Factor
303	Beaver Creek	1	250	3927	44.8%	3918	44.7%
378	Beaver Creek	2	360	5357	61.2%	4923	56.2%
354	Beaver Creek	3	400	341	3.9%	630	7.2%
467	Destruction Bay	1	600	1932	22.1%	2372	27.1%
372	Destruction Bay	2	300	4870	55.6%	3080	35.2%
230	Destruction Bay	3	220	2933	33.5%	3312	37.8%
414	Old Crow	1	600	2667	30.4%	2737	31.2%
355	Old Crow	2	400	5590	63.8%	5552	63.4%
384	Old Crow	3	170	681	7.8%	939	10.7%
422	Watson Lake	1	800	1792	20.5%	6133	70.0%
257	Watson Lake	2	800	2688	30.7%	4287	48.9%
352	Watson Lake	3	1000	2830	32.3%	4023	45.9%
258	Watson Lake	4	1500	3758	42.9%	74	0.8%
466	Watson Lake	5	750	4520	51.6%	3695	42.2%
423	Watson Lake	6	800	4683	53.5%	6114	69.8%
460	Swift River	1	90	6836	78.0%	65	0.7%
413	Swift River	2	80	1938	22.1%	8710	99.4%
375	Pelly Crossing	1	275	390	4.5%	28	0.3%
470	Pelly Crossing	2	600	90	1.0%	54	0.6%
405	Pelly Crossing	3	300	1021	11.7%	54	0.6%
310	Carmacks	1	1600	26	0.3%	17.4	0.2%
265	Ross River	1	1000	21	0.2%	22.4	0.3%
416	Haines Junction	1	1750	49.7	0.6%	17.9	0.2%
376	Teslin	1	1500	20.2	0.2%	17	0.2%
186	Stewart Crossing	3	150	94.7	1.1%	57	0.7%

(g) The forecasted replacement will be a diesel unit. If the Watson Lake LNG pilot project is successful, the unit will have bi-fuel capabilities.

YUB-YECL-40

Reference: 500 kW Mobile Generator, YECL Application, Business Case #4, page 2

Purchase a 500kW 2400V mobile generator to provide contingency power to isolated generation communities. The load in these communities has increased, resulting in the **existing 350kW** mobile generator not being large enough to provide full contingency power in the event of a planned or unplanned plant shutdown. As a result, a larger mobile unit is required. [emphasis added]

……..

The existing 350kW unit is unable to meet the current peak loads of the communities it serves. In 2011, a system peak of 359kW was recorded for Beaver Creek and Destruction Bay had a system peak of 389kW. In 2012, a system peak of 355kW was recorded for Beaver Creek and Destruction Bay had a system peak of 415kW. The mobile units will continue to provide emergency backup as well as system supply for planned regular maintenance and plant shutdowns.

Request:

Please explain what YECL intends to do with respect to the existing 350kW unit.

Response:

The existing 350kW unit is in good working condition and able to supply adequate contingency power to the communities of Beaver Creek and Destruction Bay during the summer months. The unit has less than $50,000 of net book value as of the end of 2012 so it provides additional contingency with negligible additional cost to ratepayers. As such, Yukon Electrical plans to keep the unit in service.

YUB-YECL-41

Reference: Beaver Creek Unit #2 Replacement, YECL Application, Business Case #5, page 2

Purchase new diesel generator unit complete with manufacturer-supplied and specified radiator, exhaust, and heat exchanger. Remove existing unit, install new unit and supplied devices, integrate unit into electrical supply and control systems and connect unit into waste heat and fuel systems.

Request:

With respect to the Beaver Creek generating plant unit, what is the generating capacity of Unit #2 and what is the generating size of the replacement unit?

Response:

The existing unit capacity is 360kW; the new unit capacity is 365kW.

YUB-YECL-42

Reference: Watson Lake Bi-fuel Project, YECL Application, Business Case #6, Page 2

Phase 1 of the project (2013) involves the modification of Watson Lake power plant generation Unit #5 to a bi-fuel system which allows the unit to run on a combination of diesel and natural gas (NG). The purpose of this phase is to verify that NG injection into the engine provides reliable electricity generation for a utility power system along with the environmental benefit to reduce emissions. Phase 2 of the project (2014) will convert the remaining 5 units at the Watson Lake power plant to bi-fuel operation.

…

This project will reduce the dependency of Watson Lake on a single fuel (diesel). In addition to the environmental benefits of this project to reduce emissions of particulate matter, sulfur oxides, nitrogen oxides and carbon dioxide, this initiative will assist in determining the operational and financial benefits of the use of LNG as an alternate fuel for electricity generation.

The Board notes that Unit #5 was to be bi-fuel operational in 2012

Request:

(a) Please provide an economic analysis for this project that supports YECL's decision to make Watson Lake Unit #5 bi-fuel operational.

(b) Is Unit #5 operational as a bi-fuel (LNG/diesel) unit?

  (i) If so, have emissions testing been performed? If so, please provide the results.

  (ii) If not, when does YECL expect that Unit #5 will be bi-fuel operational?

(c) Does YECL wish to update its project costs to convert all units in the Watson Lake facility to possess bi-fuel operational capabilities?

(d) YECL submits that the "natural gas will be trucked to Watson Lake from a production facility near Delta, British Columbia in a specialized, low pressure, double-walled, well-insulated or vacuum jacketed vessel." Please provide information regarding:

(i) a competitive supply market for LNG, as well as

(ii) a competitive transportation market for LNG.

(e) Please provide information regarding the component technologies that have been successfully used in on-grid applications — e.g. providing continuous power to a community like Watson Lake rather than smaller end-users such as localized generation for commercial buildings, oil and gas companies.

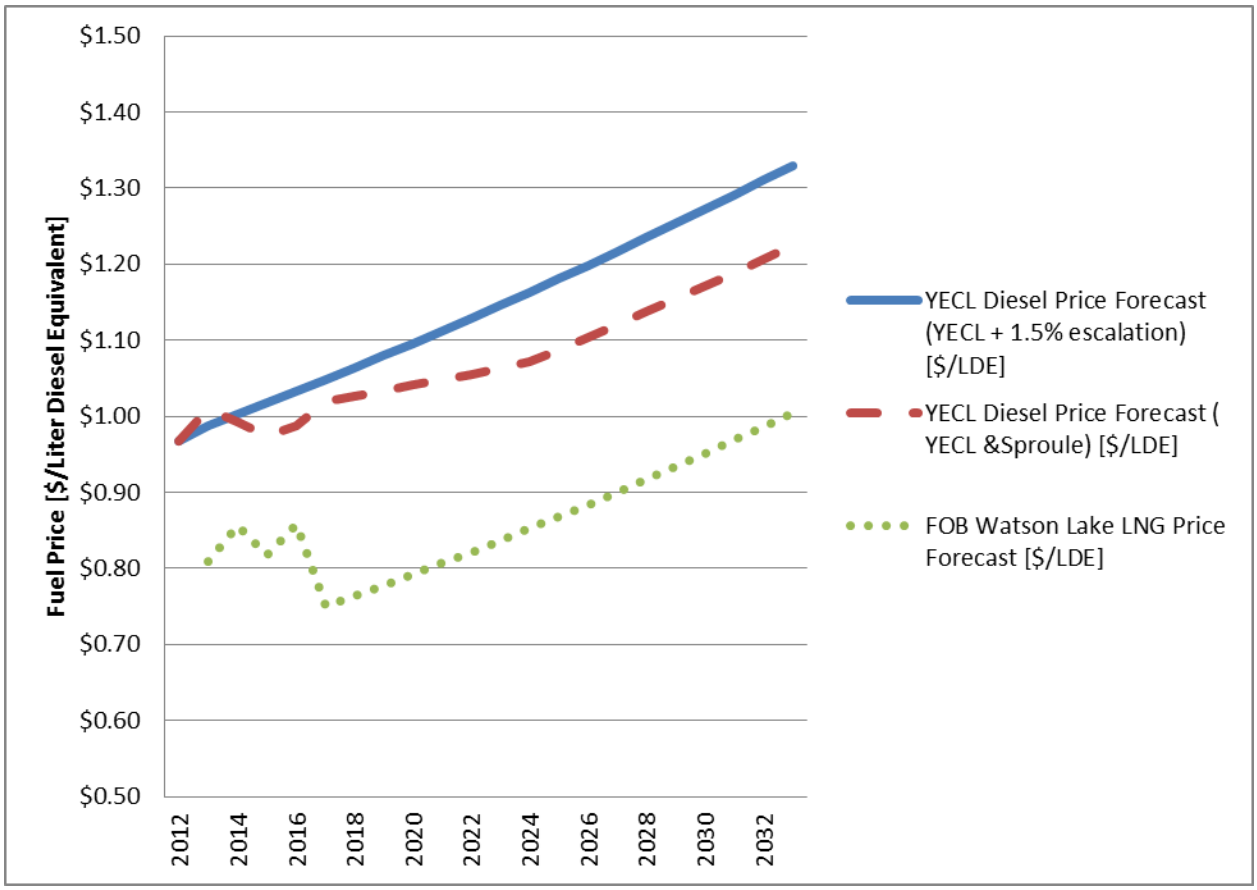
(f) For the proposed replacement of Watson Lake Unit #2, what are the differences in emissions between a new diesel-only unit and a natural-gas-only unit? Please quantify in terms of kilograms of emissions per kW.h for each case.

Response:

(a) The primary driver for the Watson Lake Bi-Fuel project is to provide local emissions reductions. It is predicted that there will be a reduction in particulate matter (PM) emissions, important to people with compromised lung function, and NOx and SOx, contributing to smog and acid rain.

The economic driver for Yukon Electrical to undertake this pilot project is fuel savings. A comparison between the price of diesel to liquefied natural gas (LNG) delivered to the Watson Lake Power Plant is found in Figure YUB-YECL-42A below.

Figure YUB-YECL-42A: Forecast Fuel Costs for Diesel and Liquefied Natural Gas (LNG) at Watson Lake Power Plant Gate



There is a predicted cost savings in fuel between LNG and diesel, even when compared to a more conservative estimate for diesel, shown as the dashed line in the figure above. The LNG forecast, shown as the dotted line, is based on contract prices for LNG as well as industry intelligence on a northern B.C. supply point in the near future. Diesel is forecast using actual delivered diesel prices at Watson Lake and a Sproule forecast for oil in the dashed line and a 1.5% escalation in the solid line (where 1.5% escalation is a commonly used rate by the industry, including Sproule http://www.sproule.com/forecasts).

When the lease cost of $22,000 per month is included in the project operations and maintenance costs, cumulative fuel savings begin in 2017. The cumulative fuel savings is one of the financial indicators used to evaluate the project and is illustrated in YUB-YECL-42(a) Attachment 1. Note that the cost of a diesel fuel tank and associated facilities are not included in this comparison and would act to increase the rate of total fuel savings for the project.

Total capital costs for the Watson Lake Bi-Fuel Project were included in Business Case #6 in the Application. These capital costs are included in Figure YUB-YECL-42B below.

Other than fuel prices, which are forecast as shown in Figure YUB-YECL-42A above, it is assumed that operations and maintenance costs escalate at 2% per year. There are no additional internal labour resources required and, therefore, labour loading does not apply; any additional project labour is carried out through contractor services and assumed to escalate at 2% per year. There are no other costs forecast for this project, other than those illustrated in YUB-YECL-42(a) Attachment 1 and Figure YUB-YECL-42B below.

When comparing the project capital costs to the cumulative fuel savings, in, a simple project payback of 9 years is shown. Simple project payback is the second financial indicator used to measure this project. The term of the project is 20 years.

Figure YUB-YECL-42B: Annual and Total Capital Costs for the Watson Lake Bi-Fuel Project

Year-End	**2012**	**2013**	**2014**	**2015**
Phase 1 - Infrastructure Costs [$]	$90,000	$363,000		
Phase 1 – Feasibility engineering in 2012/13 [$]		$222,000		
Phase 2 - Conversion of remaining 5 units to bi-fuel operation [$]			$372,000	
Total Annual Capital Cost [$]	**$90,000**	**$585,000**	**$372,000**	
Total Capital Cost [$]				**$1,047,000**

(b) No, Unit 5 is not yet operational as a bi-fuel unit. It is anticipated that the LNG facility supplying natural gas to the power plant will be licensed and commissioned in late fall of 2013. After this time, it will be possible to operate Unit 5 in bi-fuel mode.

(c) An adjustment to the forecast costs is not required at this time; however the Yukon Territorial Government requirements for testing of emissions have not yet been fully evaluated.

(d) (i) A competitive market supply for LNG does not yet exist. There is only one Western Canadian supply for LNG at this time, with two others expected to be in the market in 2014.

(ii) A competitive bid process was used to select the transport company to be used in this pilot project.

(e) To provide some background information, continuous power generation is typically accomplished by either 100% diesel or 100% natural gas. As the supply chain for liquefied natural gas (LNG) is being tested, Yukon Electrical considers a bi-fuel system to be a secure and cost effective means of supplying electricity. A bi-fuel unit can automatically switch from bi-fuel (blended natural gas with diesel) to 100% diesel operation without loss of power and there is no need to invest in new units with a bi-fuel kit at this time.

Two significant components related to the project are the bi-fuel kit for introduction of natural gas into the existing generating unit as well as the storage and vaporization equipment for receiving LNG and its conversion back into natural gas.

The bi-fuel kit manufacturer chosen by Yukon Electrical has a record of 191 engines with bi-fuel kits successfully being used for prime power generation globally. A detailed list of installation locations and end user classification has not been supplied the manufacturer as of the date of this submission. Yukon Electricals inspection of operating units includes commercial building generating sets and oil and gas installations.

A notable northern LNG facility that utilizes a storage and vaporization process similar to that proposed for Watson Lake is the Fairbanks Natural Gas LLC

facility, which has been in operation since 1998 and continues to expand its capabilities. The facility provides natural gas to residential and commercial customers.

(f) Please refer to the table below for a comparison of emissions differences for a diesel-only unit and a natural-gas-only unit. These results are based on information that can be found at:

http://www.yukonenergy.ca/downloads/db/1265_LNG%20LCA%20Pembina%20Report.pdf

Fuel	$CO2_e$ (kg/kWh)	NOx (kg/kWh)	SO2 (kg/kWh)	PM (kg/kWh)	CO (kg/kWh)
Diesel	0.619	0.0141	0	0.0008	.001
Natural Gas	0.488	0.0001	0	0.00001	0.0002

The Yukon Electrical Company Limited
Annual Forecast Operations and Maintenance Costs and Fuel Savings for the Watson Lake Bi-Fuel Projects (2012-2023)

Year-End	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
LNG Volumes (LDE)	-	101,538	710,769	1,370,769	1,853,076	1,853,076	1,853,076	1,853,076	1,853,076	1,853,076	1,853,076	1,853,076
FOB Watson Lake LNG Price Forecast ($/LDE)		$0.81	$0.86	$0.82	$0.86	$0.75	$0.76	$0.78	$0.79	$0.81	$0.82	$0.84
LNG Storage & Vapourization Charge ($/LDE)		$0.43	$0.37	$0.20	$0.15	$0.15	$0.15	$0.16	$0.16	$0.16	$0.17	$0.17
Yukon Electrical LNG Price Forecast ($/LDE)		$1.24	$1.23	$1.01	$1.01	$0.90	$0.92	$0.94	$0.95	$0.97	$0.99	$1.01
Yukon Electrical Diesel Price Forecast (Yukon Electrical + 1.5% escalation) ($/LDE)	$0.97	$0.99	$1.00	$1.02	$1.03	$1.05	$1.06	$1.08	$1.10	$1.11	$1.13	$1.15
Differential Savings at Watson Lake ($/LDE)		($0.25)	($0.23)	$0.00	$0.03	$0.15	$0.15	$0.14	$0.14	$0.14	$0.14	$0.14
Estimated Fuel Savings at Watson Lake ($)		**($25,835)**	**($160,373)**	**$4,531**	**$47,349**	**$271,843**	**$269,795**	**$267,600**	**$265,254**	**$262,752**	**$260,091**	**$257,264**
Cumulative Fuel Savings ($)		**($25,835)**	**($186,208)**	**($181,677)**	**($134,328)**	**$137,516**	**$407,310**	**$674,910**	**$940,164**	**$1,202,916**	**$1,463,007**	**$1,720,271**

YUB-YECL-43

Reference: Old Crow Plant Expansion, YECL Application, Business Case #8, pages 2, 3, 6 and 7

Yukon Electrical is planning to construct a 1,350 square foot additional generating building adjacent to the existing Old Crow plant. Both the existing building and the new building will be sized to house two diesel generators, associated equipment, and provide sufficient working space for regular work to be safely performed.

The additional building is required as the existing plant does not provide enough space to replace the existing units as they reach their end of life, as new units of the same or greater kW rating will not physically fit in the same space as the current units. It also does not provide adequate wall or floor space to facilitate the installation of new control equipment and does not allow for the addition of any more units as are required due to load growth.

…

Waste Heat

Existing waste heat system will be expanded to include the new building and units. The connection between buildings will be accomplished by above ground piping installed within containment.

Electrical Distribution

Electrical connection to both the generation system and distribution lines will be accomplished by a combination of overhead and underground methods.

As contingency, the new building will be able to supply energy to the distribution system through either the existing 2.4kV generation system or, in the case of emergency or planned maintenance, directly onto the distribution feeders.

…

In 2010, a peak of 450kW was recorded and in 2011, 478 kW was recorded.

…

If a situation arises during the winter which removes one of the larger units from operation, the other unit is then enlisted into 24/7 operation. If the situation persists, and the 24/7 running unit is required to be taken offline for a regular service; then a partial outage to the community must occur to reduce the community load to a level that can be handled by the smaller 170kW CUL 384.

Request:

(a) With respect to waste heat, please explain what is done with the waste heat.

(b) Does the existing building have the capability to supply energy to the distribution system through either the 2.4kV generating system or, in the case of emergency or planned maintenance, directly onto the distribution feeders?

(c) For each year (2013 and 2014) please provide the forecast/incurred cost of each of the forecast cost items listed under the Project Cost heading. For each item, please delineate the costs as being either labour-related or other.

(d) Do the forecast costs include any necessary training for a local operator/expertise with respect to operating and or maintaining the isolated plant? Please explain.

(e) Please explain why a full flow rated heat exchanger is required to be installed on Unit #1.

(f) Please provide load duration curves for each year of the period from January 2008 to June 2013.

(g) Over the period from January 2008 to June 2013, please provide the number of times that a partial outage to the community has occurred during the winter, which has reduced the community load to a level that was handled by the smaller CUL 384 unit. Please provide the dates for the outages as well as the reasons underpinning the partial outages.

Response:

(a) Currently, the waste heat is used to heat the offline units, the current Old Crow power plant and staff accommodations.

(b) No, the generating units and distribution feeders are interconnected through the power plant's 2.4kV switchgear. The generating units have no other means to connect to the distribution system.

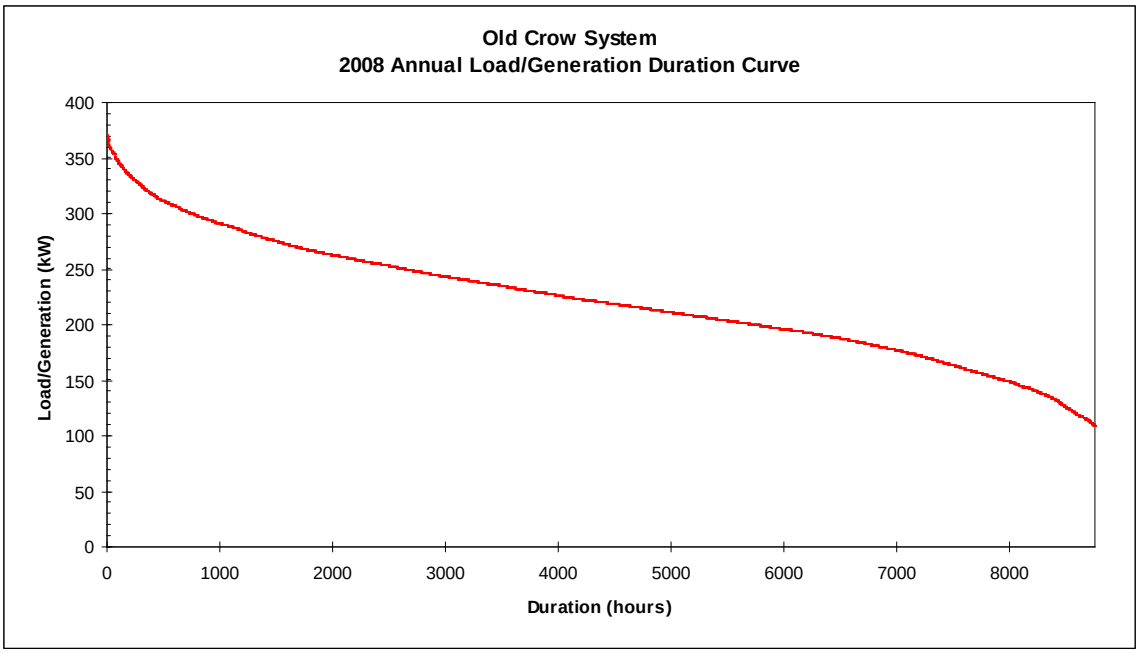
(c) The costs for each year are noted below ($000):

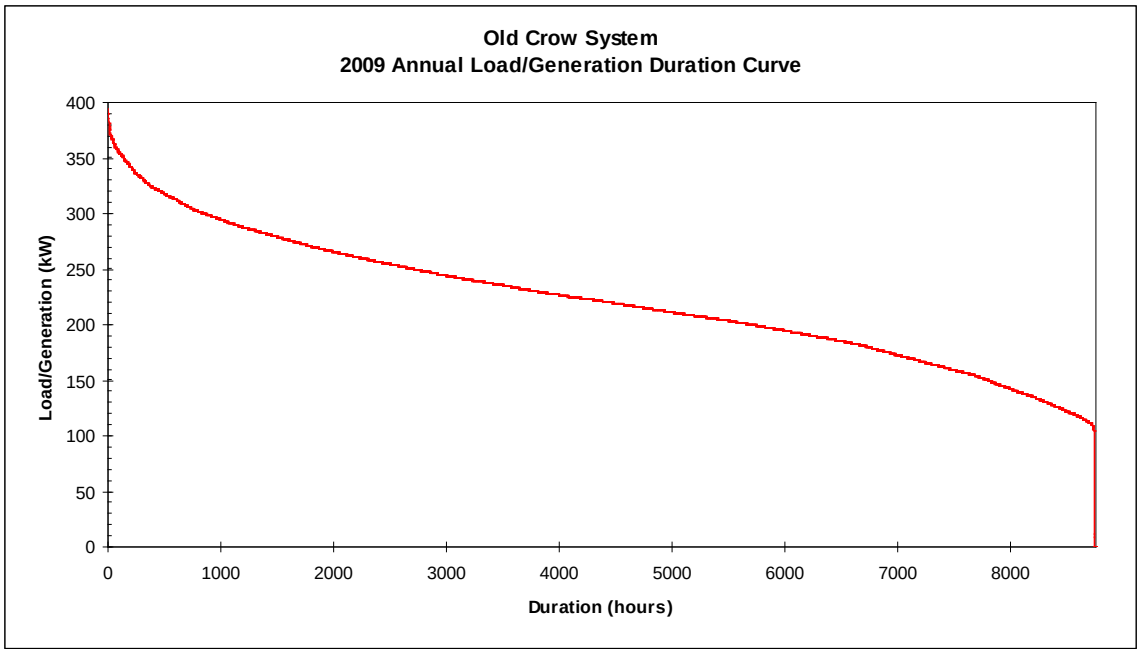
2013	
$ 100	Design contract
180	On-site contractor services for foundation work
20	Labour
$ 300	
2014	
$ 200	Freight
325	Electrical equipment and materials
1,025	Contractor services (contract to include building material and construction)
100	Labour
$ 1,650	

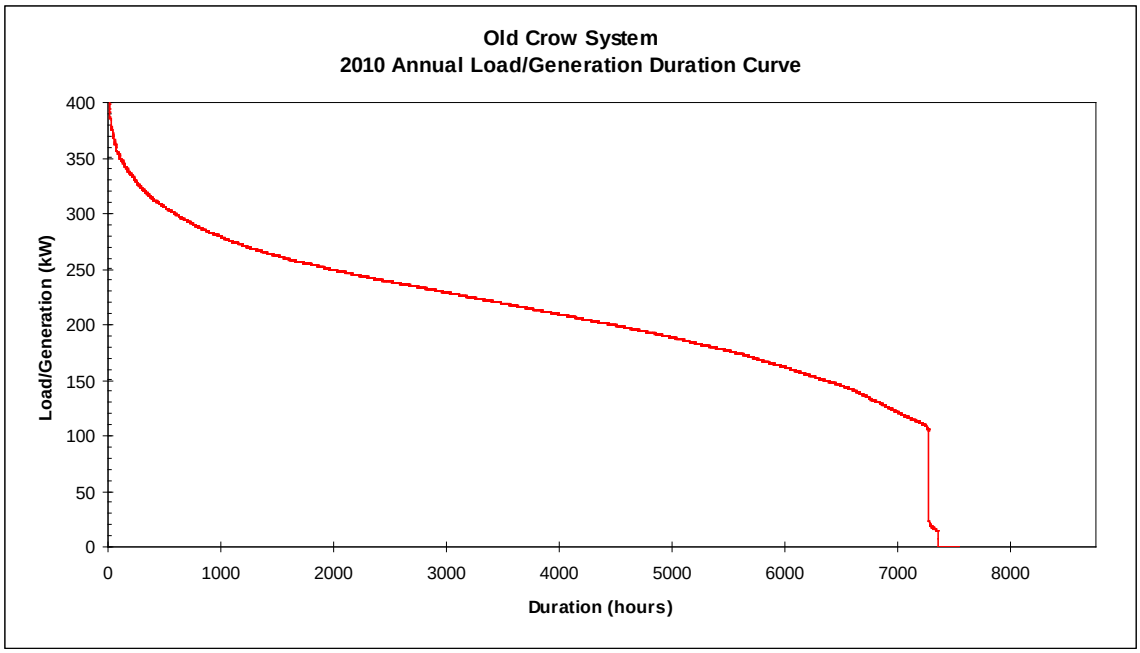
(d) Yukon Electrical's current operators will remain in place. The forecast training costs are adequate as there is no additional training required.

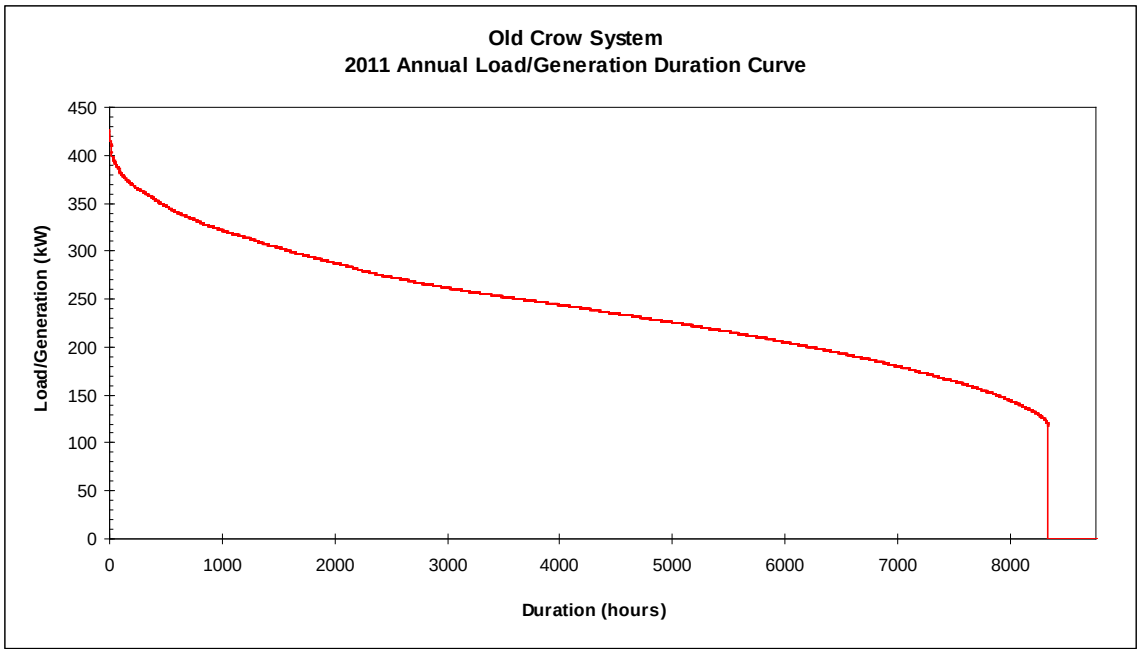
(e) The current heat exchanger is not sized for full flow from the unit therefore it only sees partial flow which limits the amount of heat transferred to the waste heat system. Situations arise when this partial level of captured heat is insufficient to effectively keep the waste heat system up to temperature.

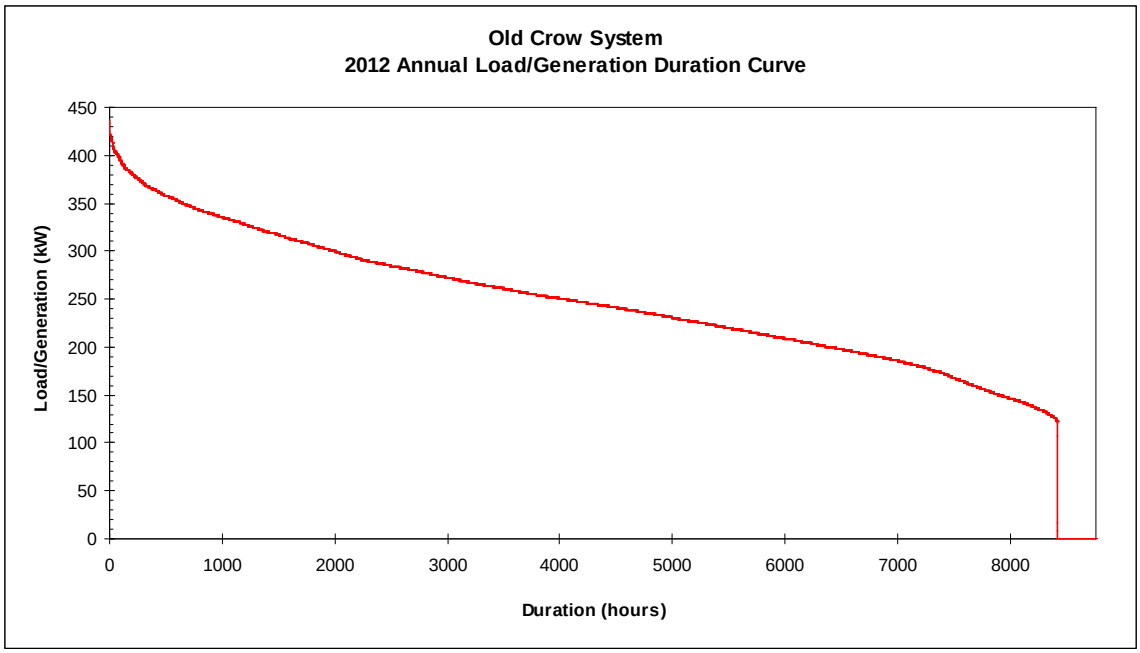
(f) Please see the following load duration curves for each year from 2008 through 2012. Data up to 2013 up to June is currently not available.


Old Crow System
2008 Annual Load/Generation Duration Curve
Load/Generation (kW)
400
350
300
250
200
150
100
50
0
0
1000
2000
3000
4000
5000
6000
7000
8000
Duration (hours)

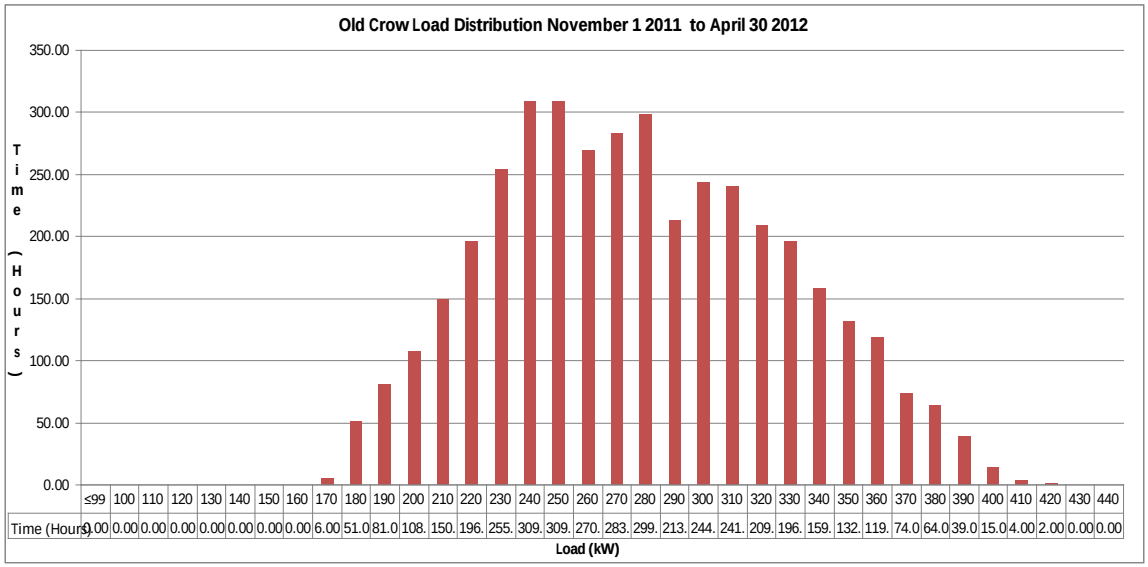

Old Crow System
2009 Annual Load/Generation Duration Curve
Load/Generation (kW)
400
350
300
250
200
150
100
50
0
0
1000
2000
3000
4000
5000
6000
7000
8000
Duration (hours)


Old Crow System
2010 Annual Load/Generation Duration Curve
Load/Generation (kW)
400
350
300
250
200
150
100
50
0
0
1000
2000
3000
4000
5000
6000
7000
8000
Duration (hours)


Old Crow System
2011 Annual Load/Generation Duration Curve
Load/Generation (kW)
450
400
350
300
250
200
150
100
50
0
0
1000
2000
3000
4000
5000
6000
7000
8000
Duration (hours)



(a) During the requested period, there were no instances where a partial outage to the community in the winter required CUL 384 to provide partial power to the community. This would require the remaining 2 larger units to be unavailable, which did not occur. During the winter months, the community load in Old Crow is greater than CUL 384 can adequately manage. As you can see in the below Old Crow Load Distribution table, there were a total of 6 hours in the period of November 1, 2011 to April 30, 2012 that community load was 170kW (maximum capacity of CUL 384). The remainder of the time, another unit in the plant would have to be utilized to provide power to the entire community.



Load (kW)	≤99	100	110	120	130	140	150	160	170	180	190	200	210	220	230	240	250	260	270	280	290	300	310	320	330	340	350	360	370	380	390	400	410	420	430	440
Time (Hours)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	51.0	81.0	108.	150.	196.	255.	309.	309.	270.	283.	299.	213.	244.	241.	209.	196.	159.	132.	119.	74.0	64.0	39.0	15.0	4.00	2.00	0.00	0.00

YUB-YECL-44

Reference: Old Crow Unit #4 Addition, YECL Application, Business Case #10, page 2

*Purchase a new **400kW** unit to be installed in the new Old Crow building (see Business Case #8). This project is required to provide full contingency generation for the isolated community of Old Crow in the event of a scheduled plant shutdown or an unplanned shutdown. [emphasis added]*

Contingency; ability to provide backup generation to the community in the event of loss of existing plant. In an emergency situation for the existing plant, transportation of mobile backup generation to this isolated fly in only community is a lengthy process due to known locations of Hercules aircraft that are out of Territory. This process would result in a long duration outage. The cost to complete this in an emergency situation would be approximately 25% of the cost of this planned project. This unit would also be able to provide full backup for scheduled maintenance shutdowns or upgrades that require a complete outage to the community. There will be a number of scheduled full shutdowns needed in the next three years.

Modernization of existing facility; plant Programmable Logic Controller is obsolete and the control system requires replacement. To complete this work a complete shutdown of the existing plant is needed. Onsite backup generation is required to avoid day long outages for multiple days, this need would be satisfied by the new unit.

Request:

(a) Please explain why the forecast $500,000 for this business case is the same as that for the replacement of Old Crow unit CUL 384 with a 250kW unit, considering that this business case provides for the "[m]odernization of existing facility; plant Programmable Logic Controller is obsolete and the control system requires replacement. To complete this work a complete shutdown of the existing plant is needed. Onsite backup generation is required to avoid day long outages for multiple days, this need would be satisfied by the new unit."

(b) During downtime for repairs on a unit in the old building, is it necessary to have all the units housed in the old building idle? If so, has this always been the case? If not, why is it being addressed now? Please explain.

(c) Please provide the number of times in the last decade that there has been a loss of an existing plant, where flown-in mobile backup generation has been necessary. Provide the dates, the length of time and the cause of each outage.

Response:

(a) The 400kW unit for Old Crow will be purchased and put in to service at the same time as the Old Crow plant expansion in 2014. This coordination will allow for cost savings due to resource utilization and sharing for both projects. Contractors that are needed for electrical, civil and welding work will already be on site. The materials needed for the Old Crow plant expansion will be freighted via large aircraft or the winter road if available, and the 400kW unit will be a small addition to the freight costs.

The 250kW unit will require its own specific shipment and contractors will be traveling to Old Crow specifically for that project in 2015. The material cost for this generating unit is approximately $50,000 less than for the 400kW unit, based on manufacturer estimates, but the higher freight and contractor costs offset the savings in the cost of the actual unit.

(b) It is not necessary to have all units idle in the old building to perform small repairs and top ends on a single unit. However, for major repairs such as major overhauls and control system work, a complete shutdown or isolation of the old building is required to safely complete the work. There are a number of scheduled full shutdowns required in the next three years.

There have been instances where major repairs required all of the units in the old building to be idle, resulting in outages that are short in duration. However, as discussed in Business Case #8, the Programmable Logic Controller (PLC) in the old building used for plant control is obsolete and is no longer supported by the manufacturer. As a result, the control system is planned to be replaced in 2016. Work such as this completed on the PLC system requires a complete shutdown of the power plant for several days which would result in multiple full outages. Flying in backup generation is an option to provide power to the community while the PLC is being worked on, but this option is very expensive and does not address the need for contingency power in the event of an emergency. The addition of Old Crow #4 would allow Yukon Electrical to continue to supply the community with power while major repairs are being completed, as well as addressing the community's requirement for additional

contingency in the event of an unplanned outage. The ability to have a safe and reliable power supply in a remote community north of the Arctic Circle is paramount. This project provides security of supply, and redundant and contingency power for the community in the event of an emergency or the unplanned loss of the current power facility.

(c) There have been no instances like these in the past decade. However, there have been 3 long duration outages (4 to 7 hours in length) in the last year to the entire community that would have been only minutes in length if the new 400kW unit and expanded Old Crow plant were in service.

YUB-YECL-45

Reference: Beaver Creek Unit #1 Replacement, YECL Application, Business Case #11, page 2

Purchase new diesel generator unit complete with manufacturer-supplied and specified radiator, exhaust, and heat exchanger. Remove existing unit, install new unit and supplied devices, integrate unit into electrical supply and control systems, and connect unit into waste heat and fuel systems.

Request:

(a) With respect to the Beaver Creek generating plant unit, what is the generating capacity of Unit #1 and what is the generating size of the replacement unit?

(b) Is the replacement unit identical to what is being proposed in Business Case #5? Please explain.

(c) Are modifications to the electrical supply and control system necessary? Please explain.

Response:

(a) The capacity of the current unit is 250kW; the generating size of the replacement unit upon which the project forecast is based is 300kW. The forecast of the replacement unit is based on the best information available to Yukon Electrical at this time. Once the actual replacement date arrives, Yukon Electrical will select a unit to ensure ideal generator capacity is selected.

(b) This project is identical in scope to that what is being proposed in Business Case #5: design and acquisition of a new generator, exhaust system, controls and labour to complete project. However, the replacement unit forecast in Business Case #5 is similarly sized to the existing Beaver Creek Unit #2, which is 365kW.

(c) Yes, in order for the new unit to operate properly within the existing power plant it will need to be integrated into the power plant control system. The existing unit (1988 Vintage) has controls that differ greatly from modern units which will require modification work to existing systems.

YUB-YECL-46

Reference: Carcross 2 MVA standby project, YECL Application, Business Case #12, page 2

This project includes the purchase and installation of a 2MW self-contained generating unit for contingency in the Carcross substation. The communities of Carcross and Tagish, including the surrounding areas, have peak load demands of 1.5MW in the winter with approximately 712 total customers.

Should a loss of generation on the Yukon Interconnected System or loss of Distribution System capability on the single radial line to the service area occur, customers in Carcross and Tagish would be without electricity. A back up power supply would provide these customers with a backup power supply similar to six other Yukon communities. A power system planning principle, "N-1," is used as a criterion to ensure contingency of supply to meet customer peak loads while a largest generating unit or major distribution/transmission component is out of service. This criterion is used in larger customer centers to provide a high reliability level to customers, however, is not practical on an individual customer basis. Yukon Electrical proposes a threshold minimum load of 1.0MWHs and 300 customers to enact the N-1 planning criteria

Request:

(a) In respect of the N-1 planning criteria, please explain what the minimum threshold load and number of customers is currently necessary to enact the N-1 criteria. Please discuss the reasons why these minimums were chosen. If there are currently no minimum thresholds, please indicate the reason(s).

(b) Please explain what has changed to influence the justification/rationale for proposing the minimum thresholds alluded to in part (a).

(c) Please provide the names of the various communities throughout the Yukon with standby generators that are connected to the Yukon Interconnected System (YIS). Please provide the dates that the generator sets were installed. Also, indicate if any of the communities were initially isolated with local generation and were subsequently connected to the YIS.

(d) With respect to outage statistics, has the line to Carcross and Tagish been identified to be a problem area?

(i) Please provide on an annual basis the number of outages and the relevant statistics for the last decade where the communities of Carcross and Tagish have been isolated from the Yukon.

(ii) Please provide the underlying reasons for the outages — e.g. lightning, trees falling on the line, poles falling, wildlife, etc. — and the costs to mitigate the identified problem areas.

(iii) Please provide the results of any reviews that have been undertaken to analyze and correct any of the problems in parts (i) and (ii).

(iv) Please provide the results of any engineering analyses that have been undertaken to analyze and determine the most effective way to complete the required work that has arisen out of part (iii) reviews.

(e) Please provide the planned and executed staged distribution improvements in the area to mitigate problems alluded to in part (d).

(f) Other than the rationale that the Carcross-Tagish area contains a population that exceeds the population of some of the communities that currently have backup generation capability is there any other rationale to support threshold minimums to enact the N-1 planning criteria?

(g) If the Board were to accept the proposed threshold minimums to enact the N-1 planning criteria, are there other communities for which the planning criteria would be enacted in the short term?

(h) Please provide a detailed cost estimate for the proposed 2MVA standby project — e.g. labour, pad, generator, substation, buildings, etc.

(i) Please discuss what alternatives were considered with respect to this project

Response:

(a) The rationale for a threshold minimum load of 1.0 MWHs to enact an N-1 planning criteria is based on the January 2006 Yukon Energy Corporation 20 Year Resource Plan that addressed a revised planning criteria for communities. An excerpt from Section 3.4 entitled “SUMMARY: REVISED CAPACITY PLANNING CRITERIA” on pages 88-89 provides the following:

2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.

3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already have back-up from another source (e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.

The selection of 300 customers is recommended as a minimum community size for locations with sufficient load that benefits a reasonably high number of customers.

(b) Yukon Electrical seeks approval for Board direction related to planning and design standards with respect to providing system redundancy.

(c) Please refer to the table below for a list of communities in the Yukon with standby generators that are connected to the Yukon Interconnected System as well as their initial installation date and indication of if they were initially isolated then connected to the YIS.

YUB – YECL – 46(c)

Power Plant Location	Company	In Service Date	Isolated then Connected to YIS
Dawson	YEC	1966	Yes
Faro	YEC	1970	Yes
Mayo	YEC	1974	Yes
Whitehorse	YEC	1968	Yes
Carmacks	YECL	1960	Yes
Haines Junction	YECL	1958	Yes*
Pelly Crossing	YECL	1966	Yes
Ross River	YECL	1966	Yes
Stewart Crossing	YECL	1965	Yes
Teslin	YECL	1962	Yes

* Haines Junction was connected to the grid in the 1970s. It was repowered in 1997 to provide standby capacity.

(d) The line to Carcross and Tagish has not been identified as a particular problem area. It is part of Yukon Electrical's maintenance and on-going improvement programs.

(i) Please refer to YUB-YECL-46 Attachment 1, tab YUB-YECL-46(d)i. for outage statistics from 2003-2012. Company Total statistics are provided as a reference. Haines Junction outage statistics are also provided as a reference for a similarly sized community. Note that the SAIFI is similar in Haines Junction – indicating similar outage frequency to Carcross & Tagish – yet the SAIDI and Index of Reliability is considerably better – indicating that outage durations are shorter in Haines Junction.

(ii) Please refer to YUB-YECL-46 Attachment 1, tab YUB-YECL-46(d)ii. for detailed statistics by CEA Coding. Statistically, the largest contributors to outages are related to a loss of supply from the Yukon Interconnected System and from trees on the distribution lines. Business Case# 12 to install a standby generating unit is proposed to address the supply and radial isolation issue at a cost of $3M. Brushing costs for the Carcross and Tagish areas since 2008 total $190,000.

(iii) Compilation of statistical data and a review of results have determined that along with the on-going brushing and distribution improvements the optimal solution to improve service reliability is a standby generator.

Please refer to YUB-YECL-46 Attachment 1, tab YUB-YECL-46(d)iii. with highlighted outage causes and commentary below:

- **Adverse Weather** – Tagish 2004 – A snowstorm caused an extended outage in 2004 to most of the town.

- **Defective Equipment** – Carcross and Tagish 2011 – Two dead-end insulators failed at Emerald Lake turnoff, causing an outage to Carcross and Tagish. The insulators were replaced.

- **Defective Equipment** – Tagish 2007 – Conductor on double dead-end structure slipped from insulator pin, causing extended outage to all of Tagish.

- **Trees** – Trees are an ongoing concern in Tagish and Carcross and Yukon Electrical's brushing program targets these areas.

(iv) Other options considered included:

- Providing an alternative feed from Jakes Corner from a new 34.5kV – 25kV substation and 15km line to the community of Tagish. This alternative feed provides a looped supply configuration to the communities however is still supplied off of the main radial feed line from Whitehorse.

- Acceleration of the brushing program to reduce incident outages caused by trees on the line. However, the inherent risk from being on a long radial feed remains.

- Hiring a Serviceman to staff the Carcross and Tagish region, similar to Haines Junction. Though not as remote as Haines Junction, this option can more rapidly address localized incidents. This does not assist with the loss of supply issue.

(e) Widening of the right of way has been undertaken. Some sections of line have been rebuilt along the road side right of way in place of cross country routing. This removes the trees entirely from the road side of the power line and speeds up patrolling/trouble shooting times.

(f) Additional rational to enact the N-1 planning criteria based on minimum thresholds for electrical load and population base is related to providing electrical

service for emergency services in the Carcross-Tagish area that include ambulance, fire protection, emergency measures and policing services that require a reliable source of power to function properly. Yukon Electrical strives to ensure reliable service to meet the needs of its customers and communities.

(g) Additional community areas that would meet the planning criteria include the greater Marsh Lake area (New Constabulary, Old Constabulary, Judas Creek, Army Beach, South McClintock) that would meet the thresholds.

Haines Junction is another community that due to load growth in the near future would not have sufficient generating capacity to provide 100% standby capacity. This could be met with a larger sized unit. As such, it would be beneficial for Yukon Electrical to obtain guidance from the Board with respect to ensuring that standby capability for existing communities is maintained.

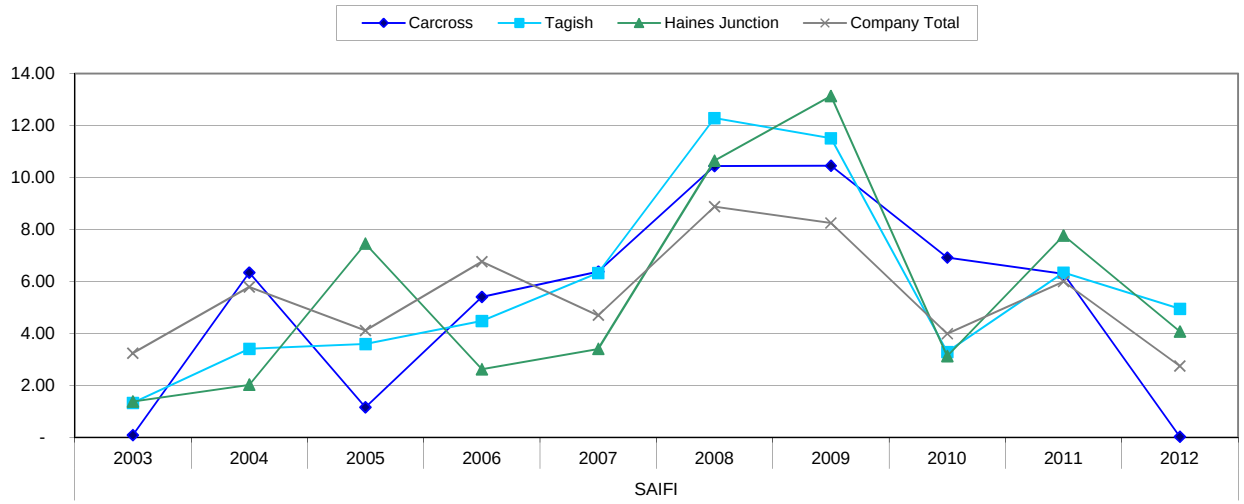
(h) Detailed cost estimate for the proposed 2MVA standby project:

2,000kW Self-contained generator (sized for cold load pickup)	$2,500,000
Engineering, Design	100,000
Transformer, cables, vault, cable tray	100,000
OSS (grid inter-tie/synchronization)	75,000
Substation bus extension	50,000
Civil – genset pad, fuel tank pad	50,000
Fuel tank, piping, utilidor	50,000
SCADA and PLC	35,000
Ground grid	20,000
Fence	20,000
	$3,000,000

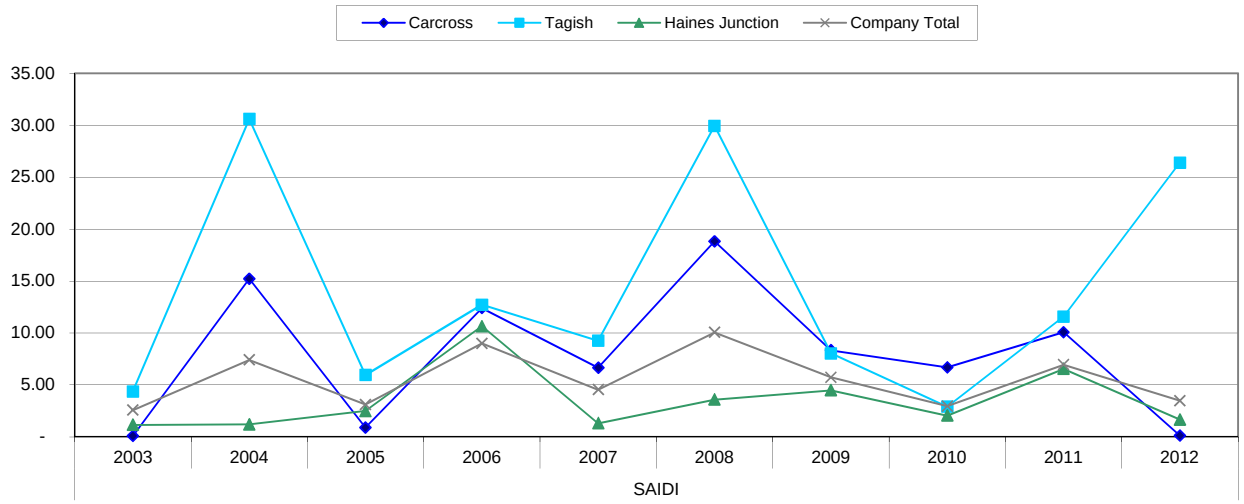
(i) For additional information on options, please also refer to response (d)(iv) above. The community of Carcross is fed from a single 34.5kV line off of the 34.5kV line from Whitehorse to Teslin. The community of Tagish is supplied by a 25kV line from the substation at Carcross. An option to close the loop back to the Whitehorse line by including a new substation and line would address issues related to the vulnerability of the radial feed portion to Carcross and Tagish, but

does not address the radial supply line out of Whitehorse. The approximate cost of this option is $3.5M comprised of $1.5M for a new substation and $2.0M for new line. This alternative feed will also be supplied by the radial line from Whitehorse and, therefore, does not provide the security of supply.

Yukon Electrical Company Limited
Outage Indices for Carcross and Tagish (2003-2012)
YUB-YECL-46(d) i.

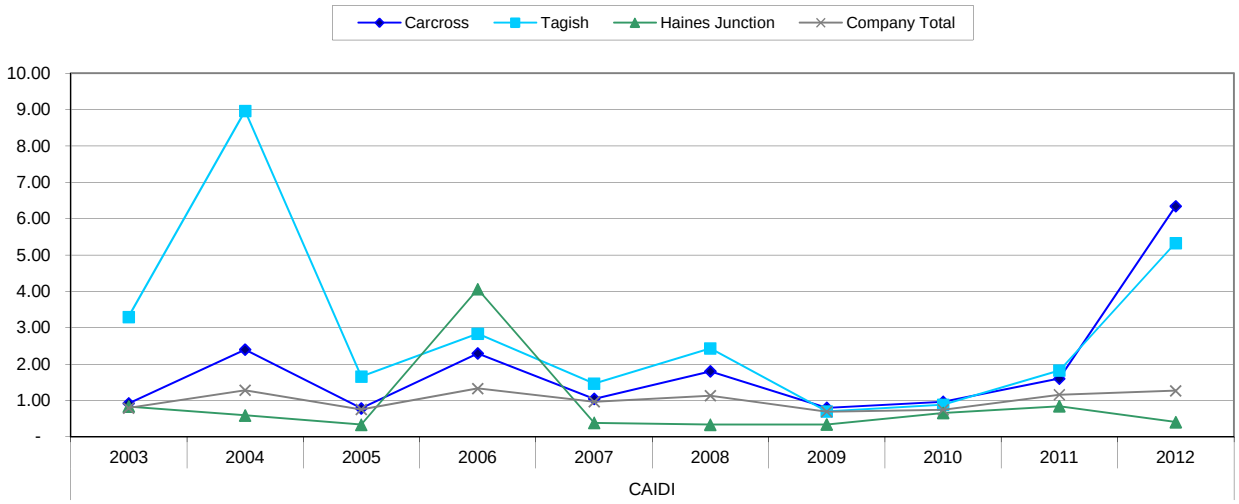


	SAIFI									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	0.09	6.34	1.15	5.40	6.38	10.44	10.45	6.92	6.29	0.02
Tagish	1.32	3.41	3.59	4.48	6.32	12.29	11.51	3.29	6.34	4.95
Haines Junction	1.38	2.02	7.45	2.62	3.40	10.65	13.13	3.13	7.76	4.07
Company Total	3.23	5.78	4.11	6.76	4.69	8.87	8.24	3.98	6.00	2.74

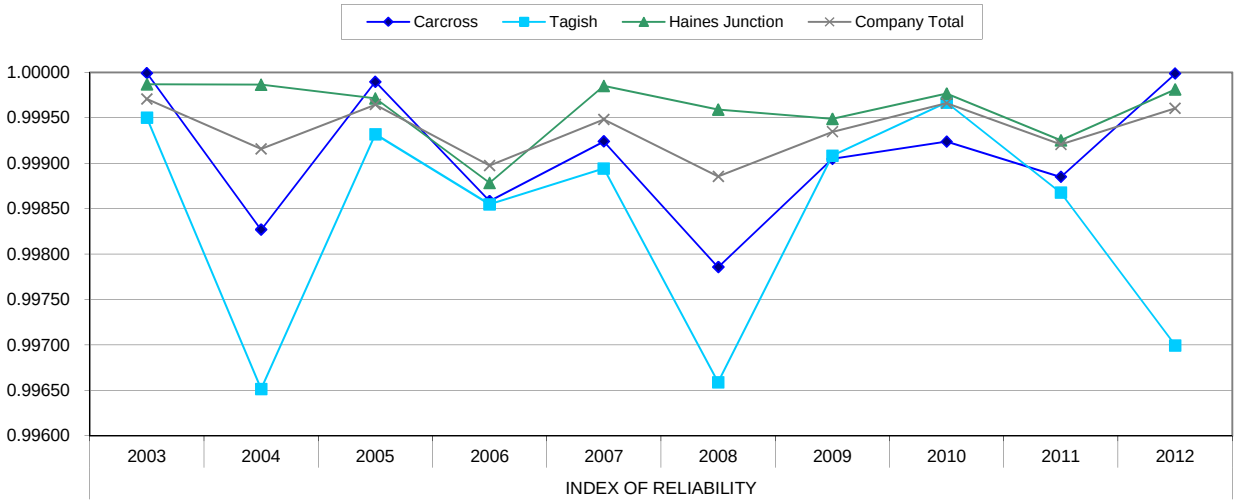


	SAIDI									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	0.08	15.21	0.90	12.40	6.66	18.83	8.33	6.68	10.08	0.12
Tagish	4.37	30.60	5.96	12.72	9.26	29.95	8.04	2.91	11.59	26.40
Haines Junction	1.15	1.19	2.50	10.65	1.31	3.59	4.48	2.05	6.54	1.66
Company Total	2.57	7.41	3.11	8.99	4.54	10.06	5.73	2.97	6.95	3.48

Yukon Electrical Company Limited
Outage Indices for Carcross and Tagish (2003-2012)
YUB-YECL-46(d) i.



	CAIDI									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	0.92	2.40	0.78	2.30	1.04	1.80	0.80	0.97	1.60	6.34
Tagish	3.30	8.97	1.66	2.84	1.47	2.44	0.70	0.89	1.83	5.34
Haines Junction	0.83	0.59	0.34	4.07	0.39	0.34	0.34	0.66	0.84	0.41
Company Total	0.79	1.28	0.76	1.33	0.97	1.13	0.70	0.74	1.16	1.27



	INDEX OF RELIABILITY									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	0.99999	0.99827	0.99990	0.99858	0.99924	0.99786	0.99905	0.99924	0.99885	0.99999
Tagish	0.99950	0.99652	0.99932	0.99855	0.99894	0.99659	0.99908	0.99967	0.99868	0.99699
Haines Junction	0.99987	0.99986	0.99971	0.99878	0.99985	0.99959	0.99949	0.99977	0.99925	0.99981
Company Total	0.99971	0.99916	0.99965	0.99897	0.99948	0.99885	0.99935	0.99966	0.99921	0.99960

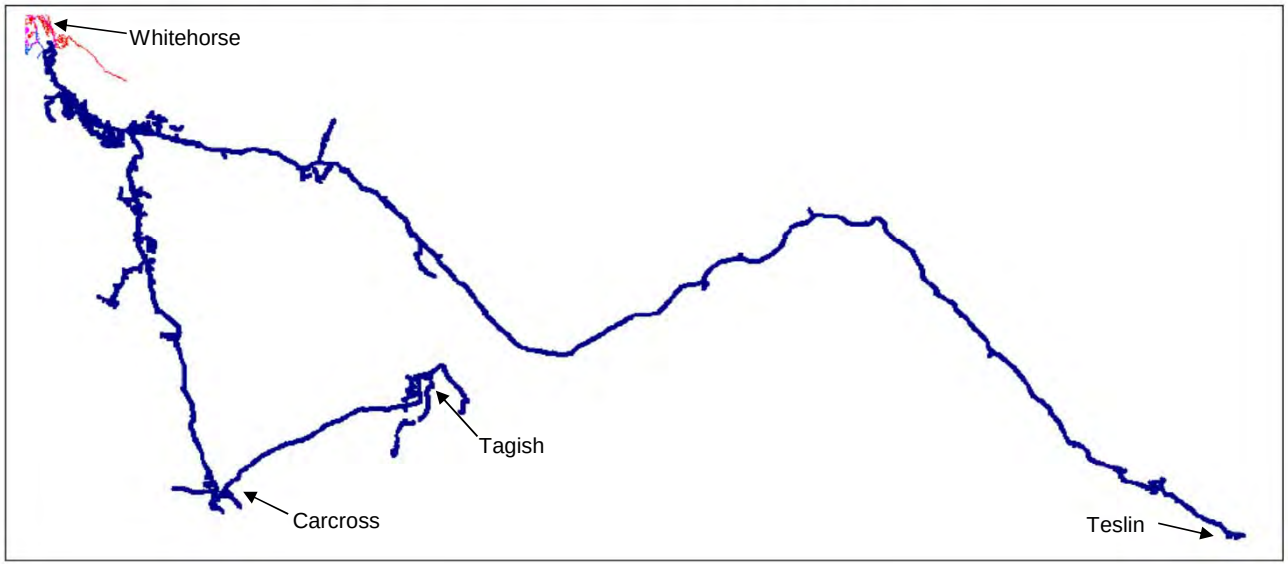
Yukon Electrical Company Limited
Outage Indices for Carcross and Tagish (2003-2012)
YUB-YECL-46(d) i.

	NUMBER OF INTERRUPTIONS									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	6	12	4	9	9	17	16	10	11	6
Tagish	12	5	14	16	18	29	23	9	12	10
Haines Junction	13	24	36	11	16	43	32	39	22	12
Company Total	465	436	410	486	418	620	501	473	348	311

	NUMBER OF CUSTOMERS									
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Carcross	258	266	274	274	280	286	293	302	307	313
Tagish	318	330	335	340	345	353	352	353	360	364
Haines Junction	460	463	465	468	476	481	486	496	510	513
Company Total	13,982	14,203	14,464	14,711	15,023	15,315	15,573	15,861	16,254	16,698

The following is a system diagram of 9L - the line that feeds Carcross, Tagish, Teslin & Marsh Lake. Note it is a long radial feed.

S150-52-22, 9L
Feeds Macrae, Carcross, Tagish, Marsh Lake, Teslin (S9833, S6839, S6840)



Yukon Electrical Company Limited
Outage Indices for Carcross and Tagish (2003-2012)
YUB-YECL-46(d) ii.

CARCROSS

YEAR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NUMBER OF CUSTOMERS	258	266	274	274	280	286	293	302	307	313
OUTAGE COST				2,182	531	2,005	1,884	3,340	5,266	2,565

TAGISH

YEAR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NUMBER OF CUSTOMERS	318	330	335	340	345	353	352	353	360	364
OUTAGE COST				6,145	4,720	7,756	6,074	2,085	6,140	10,707

HAINES JUNCTION

YEAR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NUMBER OF CUSTOMERS	460	463	465	468	476	481	486	496	510	513
OUTAGE COST				7,527	3,307	14,826	6,884	4,961	17,208	3,944

COMPANY TOTAL

YEAR	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NUMBER OF CUSTOMERS	13,982	14,203	14,464	14,711	15,023	15,315	15,573	15,861	16,254	16,698
OUTAGE COST				122,751	120,349	182,109	129,218	134,491	193,181	220,271

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	1	-	-	-	-	-	-	-	-	-	**1**
Adverse Weather	-	2	-	3	-	1	3	1	1	-	**11**
Defective Equipment	-	-	-	1	1	2	1	2	2	2	**11**
Foreign Interference	3	-	1	1	1	-	1	2	2	1	**12**
Human Element	-	-	-	-	-	-	-	-	-	1	**1**
Lightning	-	-	1	-	-	-	-	-	-	-	**1**
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-	**-**
Loss of Supply - Yukon Energy	-	-	2	1	2	7	7	2	5	-	**26**
Scheduled	1	2	-	-	4	4	1	-	1	-	**13**
Trees	-	8	-	-	-	3	2	3	-	-	**16**
Unknown/Other	1	-	-	3	1	-	1	-	-	2	**8**
Total	**6**	**12**	**4**	**9**	**9**	**17**	**16**	**10**	**11**	**6**	**100**

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	-	-	-	-	-	1	-	-	-	-	**1**
Adverse Weather	-	1	2	4	1	5	6	-	2	1	**22**
Defective Equipment	4	-	2	2	4	1	2	-	1	1	**17**
Foreign Interference	1	-	6	3	2	2	3	1	-	1	**19**
Human Element	-	-	-	-	1	-	1	-	-	-	**2**
Lightning	-	-	-	-	-	-	-	-	-	-	**-**
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-	**-**
Loss of Supply - Yukon Energy	-	-	2	1	2	7	7	2	5	-	**26**
Scheduled	4	-	-	2	3	7	2	1	-	3	**22**
Trees	3	4	2	2	3	5	2	5	4	4	**34**
Unknown/Other	-	-	-	2	2	1	-	-	-	-	**5**
Total	**12**	**5**	**14**	**16**	**18**	**29**	**23**	**9**	**12**	**10**	**148**

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	-	-	-	-	1	-	-	-	-	-	**1**
Adverse Weather	2	8	1	-	-	12	9	1	3	1	**37**
Defective Equipment	-	3	3	-	1	3	4	1	2	2	**19**
Foreign Interference	1	3	1	3	1	6	3	7	6	4	**35**
Human Element	1	1	1	1	-	-	1	1	-	-	**6**
Lightning	-	-	-	-	-	-	-	-	-	-	**-**
Loss of Supply - Yukon Electrical	-	-	-	1	-	-	-	-	-	-	**1**
Loss of Supply - Yukon Energy	-	-	5	1	5	17	6	12	3	4	**53**
Scheduled	6	4	18	1	6	2	5	9	-	1	**52**
Trees	2	3	5	3	1	2	-	3	6	-	**25**
Unknown/Other	1	2	2	1	1	1	4	5	2	-	**19**
Total	**13**	**24**	**36**	**11**	**16**	**43**	**32**	**39**	**22**	**12**	**248**

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	5	4	2	-	8	6	2	4	2	2	**35**
Adverse Weather	68	67	16	73	26	65	66	24	21	23	**449**
Defective Equipment	51	43	49	40	41	56	63	46	46	51	**486**
Foreign Interference	92	74	73	75	99	103	89	86	88	84	**863**
Human Element	12	11	8	15	18	3	14	10	4	5	**100**
Lightning	9	9	9	18	13	2	6	14	5	3	**88**
Loss of Supply - Yukon Electrical	1	3	7	39	21	25	24	12	6	7	**145**
Loss of Supply - Yukon Energy	21	27	36	54	36	121	85	70	60	21	**531**
Scheduled	112	81	104	80	109	118	83	105	47	40	**879**
Trees	47	83	75	54	28	98	35	51	46	50	**567**
Unknown/Other	47	34	31	38	19	23	34	51	23	25	**325**
Total	**465**	**436**	**410**	**486**	**418**	**620**	**501**	**473**	**348**	**311**	**4,468**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	0.01	-	3.04	-	0.01	1.04	0.00	0.07	-
Defective Equipment	-	-	-	0.04	0.00	0.01	1.03	0.03	1.04	0.01
Foreign Interference	0.07	-	0.11	0.00	0.00	-	0.08	0.02	0.01	0.00
Human Element	-	-	-	-	-	-	-	-	-	0.00
Lightning	-	-	0.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	1.03	1.62	2.00	7.28	7.24	2.05	5.16	-
Scheduled	0.01	0.01	-	-	2.63	1.05	1.03	-	0.02	-
Trees	-	6.32	-	-	-	2.09	0.01	4.81	-	-
Unknown/Other	0.01	-	-	0.69	1.74	-	0.01	-	-	0.01
Total	**0.09**	**6.34**	**1.15**	**5.40**	**6.38**	**10.44**	**10.45**	**6.92**	**6.29**	**0.02**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	0.01	-	-	-	-
Adverse Weather	-	0.97	1.21	0.04	0.51	0.06	0.07	-	0.01	0.00
Defective Equipment	0.02	-	0.01	0.01	2.43	0.01	1.12	-	1.05	0.43
Foreign Interference	0.01	-	0.73	0.01	0.01	0.01	1.06	0.64	-	0.00
Human Element	-	-	-	-	0.01	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	1.04	1.08	2.00	7.16	7.38	2.11	5.18	-
Scheduled	0.29	-	-	1.04	0.03	1.37	0.69	0.09	-	2.08
Trees	1.00	2.44	0.60	0.38	0.32	3.65	1.18	0.45	0.11	2.43
Unknown/Other	-	-	-	1.91	1.00	0.02	-	-	-	-
Total	**1.32**	**3.41**	**3.59**	**4.48**	**6.32**	**12.29**	**11.51**	**3.29**	**6.34**	**4.95**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	0.02	-	-	-	-	-
Adverse Weather	0.32	0.40	0.00	-	-	0.77	1.02	-	1.04	0.00
Defective Equipment	-	0.02	0.01	-	0.50	0.03	0.01	0.00	0.27	0.03
Foreign Interference	0.00	0.44	0.00	0.01	0.00	0.03	0.28	0.01	0.03	0.01
Human Element	0.15	0.02	0.00	0.00	-	-	0.02	0.39	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	1.15	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	5.29	1.15	2.71	9.43	5.87	1.58	2.95	4.01
Scheduled	0.32	0.14	2.08	0.04	0.10	0.09	2.94	0.73	-	0.02
Trees	0.05	0.04	0.05	0.07	0.06	0.29	-	0.00	3.48	-
Unknown/Other	0.54	0.97	0.00	0.18	0.00	0.00	3.00	0.40	0.01	-
Total	**1.38**	**2.02**	**7.45**	**2.62**	**3.40**	**10.65**	**13.13**	**3.13**	**7.76**	**4.07**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	0.00	0.00	0.00	-	0.00	0.00	0.00	0.00	0.01	0.00
Adverse Weather	0.42	1.09	0.22	0.34	0.10	0.17	0.13	0.18	0.04	0.10
Defective Equipment	0.44	0.45	0.21	0.16	0.30	0.46	0.69	0.13	0.18	0.48
Foreign Interference	0.08	0.62	0.33	0.17	0.31	0.42	0.38	0.08	0.52	0.25
Human Element	0.08	0.05	0.02	0.17	0.15	0.01	0.03	0.05	0.04	0.03
Lightning	0.03	0.24	0.01	0.05	0.00	0.00	0.01	0.01	0.11	0.01
Loss of Supply - Yukon Electrical	0.01	0.04	0.04	0.52	0.25	0.38	0.22	0.21	0.18	0.16
Loss of Supply - Yukon Energy	0.96	1.67	2.24	4.58	2.90	5.91	5.71	2.49	3.94	0.44
Scheduled	0.48	0.43	0.54	0.45	0.39	0.64	0.52	0.47	0.37	0.20
Trees	0.28	0.47	0.41	0.16	0.07	0.71	0.17	0.17	0.38	0.21
Unknown/Other	0.46	0.71	0.09	0.17	0.24	0.17	0.38	0.19	0.22	0.85
Total	**3.23**	**5.78**	**4.11**	**6.76**	**4.69**	**8.87**	**8.24**	**3.98**	**6.00**	**2.74**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	0.01	-	1.93	-	0.02	2.00	0.01	0.14	-
Defective Equipment	-	-	-	0.03	0.00	0.03	0.08	0.08	4.74	0.02
Foreign Interference	0.07	-	0.23	0.00	0.00	-	0.08	0.04	0.01	0.00
Human Element	-	-	-	-	-	-	-	-	-	0.02
Lightning	-	-	0.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	0.67	9.18	0.90	10.07	3.71	1.48	5.16	-
Scheduled	0.00	0.02	-	-	4.45	2.50	2.41	-	0.03	-
Trees	-	15.18	-	-	-	6.21	0.02	5.07	-	-
Unknown/Other	0.00	-	-	1.27	1.30	-	0.02	-	-	0.08
Total	**0.08**	**15.21**	**0.90**	**12.40**	**6.66**	**18.83**	**8.33**	**6.68**	**10.08**	**0.12**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	0.03	-	-	-	-
Adverse Weather	-	7.52	1.73	0.58	0.93	0.05	0.12	-	0.01	0.00
Defective Equipment	0.18	-	0.14	0.02	5.70	0.04	0.36	-	4.80	1.17
Foreign Interference	0.03	-	1.17	0.04	0.03	0.02	1.68	0.37	-	0.00
Human Element	-	-	-	-	0.01	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	0.68	6.28	0.90	9.93	3.78	1.55	5.10	-
Scheduled	1.08	-	-	1.82	0.06	2.61	0.37	0.27	-	4.36
Trees	3.08	23.09	2.24	2.80	0.89	17.23	1.73	0.73	1.68	20.86
Unknown/Other	-	-	-	1.17	0.75	0.03	-	-	-	-
Total	**4.37**	**30.60**	**5.96**	**12.72**	**9.26**	**29.95**	**8.04**	**2.91**	**11.59**	**26.40**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	0.01	-	-	-	-	-
Adverse Weather	0.24	0.28	0.01	-	-	0.18	0.56	-	0.14	0.00
Defective Equipment	-	0.21	0.01	-	0.33	0.09	0.02	0.00	0.35	0.08
Foreign Interference	0.00	0.36	0.00	0.01	0.00	0.07	0.08	0.14	0.09	0.02
Human Element	0.01	0.05	0.00	0.00	-	-	0.01	0.06	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	9.00	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	1.40	0.58	0.81	2.46	0.97	0.33	1.54	1.53
Scheduled	0.67	0.16	1.04	0.07	0.13	0.11	1.84	1.35	-	0.03
Trees	0.04	0.10	0.02	0.16	0.02	0.68	-	0.01	4.41	-
Unknown/Other	0.19	0.03	0.00	0.83	0.00	0.01	1.00	0.16	0.00	-
Total	**1.15**	**1.19**	**2.50**	**10.65**	**1.31**	**3.59**	**4.48**	**2.05**	**6.54**	**1.66**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	0.00	0.00	0.00	-	0.01	0.00	0.01	0.00	0.00	0.00
Adverse Weather	0.24	3.66	0.10	0.52	0.12	0.09	0.20	0.10	0.03	0.04
Defective Equipment	0.64	0.64	0.16	0.52	0.73	0.28	0.62	0.07	0.38	0.95
Foreign Interference	0.10	0.22	0.34	0.17	0.26	0.64	0.34	0.23	0.46	0.30
Human Element	0.01	0.01	0.01	0.15	0.23	0.01	0.02	0.02	0.04	0.08
Lightning	0.01	0.20	0.00	0.08	0.04	0.00	0.01	0.02	0.02	0.02
Loss of Supply - Yukon Electrical	0.00	0.01	0.01	0.40	0.03	0.13	0.05	0.03	0.06	0.08
Loss of Supply - Yukon Energy	0.29	0.66	0.99	6.09	2.17	6.41	3.09	1.38	4.37	0.18
Scheduled	0.77	0.41	0.97	0.77	0.61	0.98	0.85	0.63	0.85	0.48
Trees	0.22	1.03	0.38	0.16	0.17	1.41	0.27	0.41	0.57	0.81
Unknown/Other	0.28	0.57	0.14	0.15	0.18	0.11	0.27	0.07	0.16	0.55
Total	**2.57**	**7.41**	**3.11**	**8.99**	**4.54**	**10.06**	**5.73**	**2.97**	**6.95**	**3.48**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	1.12	-	0.63	-	3.25	1.92	2.25	2.08	-
Defective Equipment	-	-	-	0.67	0.50	3.03	0.08	3.00	4.58	2.54
Foreign Interference	1.05	-	2.00	0.97	1.25	-	1.01	2.10	1.50	1.50
Human Element	-	-	-	-	-	-	-	-	-	5.13
Lightning	-	-	1.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	0.65	5.65	0.45	1.38	0.51	0.72	1.00	-
Scheduled	0.40	1.47	-	-	1.69	2.38	2.33	-	1.83	-
Trees	-	2.40	-	-	-	2.97	1.69	1.05	-	-
Unknown/Other	0.30	-	-	1.83	0.75	-	1.50	-	-	13.17
Total	**0.92**	**2.40**	**0.78**	**2.30**	**1.04**	**1.80**	**0.80**	**0.97**	**1.60**	**6.34**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	3.25	-	-	-	-
Adverse Weather	-	7.75	1.43	13.25	1.83	0.90	1.67	-	2.38	1.25
Defective Equipment	11.73	-	9.16	2.00	2.35	6.75	0.32	-	4.58	2.70
Foreign Interference	2.08	-	1.62	3.05	1.75	2.00	1.58	0.58	-	1.33
Human Element	-	-	-	-	0.70	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	0.65	5.80	0.45	1.39	0.51	0.73	0.98	-
Scheduled	3.70	-	-	1.76	1.72	1.90	0.53	2.93	-	2.10
Trees	3.07	9.45	3.73	7.45	2.74	4.72	1.46	1.63	15.51	8.58
Unknown/Other	-	-	-	0.61	0.75	2.00	-	-	-	-
Total	**3.30**	**8.97**	**1.66**	**2.84**	**1.47**	**2.44**	**0.70**	**0.89**	**1.83**	**5.34**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	0.50	-	-	-	-	-
Adverse Weather	0.74	0.70	3.90	-	-	0.23	0.54	-	0.14	1.00
Defective Equipment	-	9.87	1.89	-	0.67	3.45	1.60	0.50	1.32	2.41
Foreign Interference	0.50	0.83	0.75	1.32	1.50	1.97	0.30	9.92	3.56	2.59
Human Element	0.08	2.80	1.00	0.83	-	-	0.35	0.15	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	7.80	-	-	-	-	-	-
Loss of Supply - Yukon Energy	-	-	0.27	0.50	0.30	0.26	0.17	0.21	0.52	0.38
Scheduled	2.13	1.15	0.50	1.50	1.29	1.15	0.63	1.85	-	1.42
Trees	0.83	2.84	0.40	2.23	0.35	2.34	-	1.74	1.27	-
Unknown/Other	0.35	0.03	0.70	4.56	0.15	2.50	0.33	0.41	0.70	-
Total	**0.83**	**0.59**	**0.34**	**4.07**	**0.39**	**0.34**	**0.34**	**0.66**	**0.84**	**0.41**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	0.24	0.85	2.00	-	3.02	2.54	2.03	6.96	0.38	4.00
Adverse Weather	0.57	3.35	0.47	1.53	1.16	0.52	1.60	0.57	0.62	0.42
Defective Equipment	1.45	1.43	0.76	3.28	2.48	0.60	0.89	0.55	2.09	1.99
Foreign Interference	1.24	0.35	1.02	0.98	0.84	1.51	0.89	2.71	0.89	1.19
Human Element	0.10	0.23	0.44	0.90	1.55	1.08	0.70	0.44	1.03	2.26
Lightning	0.39	0.85	0.71	1.43	9.67	0.89	0.99	2.57	0.21	1.03
Loss of Supply - Yukon Electrical	0.04	0.25	0.20	0.78	0.13	0.34	0.24	0.13	0.33	0.47
Loss of Supply - Yukon Energy	0.31	0.39	0.44	1.33	0.75	1.09	0.54	0.55	1.11	0.40
Scheduled	1.61	0.94	1.80	1.71	1.58	1.53	1.63	1.34	2.33	2.43
Trees	0.79	2.19	0.93	1.02	2.46	2.00	1.60	2.38	1.49	3.86
Unknown/Other	0.61	0.80	1.47	0.88	0.75	0.66	0.71	0.37	0.73	0.65
Total	**0.79**	**1.28**	**0.76**	**1.33**	**0.97**	**1.13**	**0.70**	**0.74**	**1.16**	**1.27**

INDEX OF RELIABILITY

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	8760	8784	8760	8760	8760	8784	8760	8760	8760	8784
Adverse Environment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Adverse Weather	1.00000	1.00000	1.00000	0.99978	1.00000	1.00000	0.99977	1.00000	0.99998	1.00000
Defective Equipment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	0.99999	0.99999	0.99946	1.00000
Foreign Interference	0.99999	1.00000	0.99997	1.00000	1.00000	1.00000	0.99999	1.00000	1.00000	1.00000
Human Element	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Lightning	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Electrical	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Energy	1.00000	1.00000	0.99992	0.99895	0.99990	0.99885	0.99958	0.99983	0.99941	1.00000
Scheduled	1.00000	1.00000	1.00000	1.00000	0.99949	0.99972	0.99972	1.00000	1.00000	1.00000
Trees	1.00000	0.99827	1.00000	1.00000	1.00000	0.99929	1.00000	0.99942	1.00000	1.00000
Unknown/Other	1.00000	1.00000	1.00000	0.99986	0.99985	1.00000	1.00000	1.00000	1.00000	0.99999
Total	**0.99999**	**0.99827**	**0.99990**	**0.99858**	**0.99924**	**0.99786**	**0.99905**	**0.99924**	**0.99885**	**0.99999**

INDEX OF RELIABILITY

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	8760	8784	8760	8760	8760	8784	8760	8760	8760	8784
Adverse Environment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Adverse Weather	1.00000	0.99914	0.99980	0.99993	0.99989	0.99999	0.99999	1.00000	1.00000	1.00000
Defective Equipment	0.99998	1.00000	0.99998	1.00000	0.99935	1.00000	0.99996	1.00000	0.99945	0.99987
Foreign Interference	1.00000	1.00000	0.99987	0.99999	1.00000	1.00000	0.99981	0.99996	1.00000	1.00000
Human Element	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Lightning	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Electrical	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Energy	1.00000	1.00000	0.99992	0.99928	0.99990	0.99887	0.99957	0.99982	0.99942	1.00000
Scheduled	0.99988	1.00000	1.00000	0.99979	0.99999	0.99970	0.99996	0.99997	1.00000	0.99950
Trees	0.99965	0.99737	0.99974	0.99968	0.99990	0.99804	0.99980	0.99992	0.99981	0.99762
Unknown/Other	1.00000	1.00000	1.00000	0.99987	0.99991	1.00000	1.00000	1.00000	1.00000	1.00000
Total	**0.99950**	**0.99652**	**0.99932**	**0.99855**	**0.99894**	**0.99659**	**0.99908**	**0.99967**	**0.99868**	**0.99699**

INDEX OF RELIABILITY

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	8760	8784	8760	8760	8760	8784	8760	8760	8760	8784
Adverse Environment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Adverse Weather	0.99997	0.99997	1.00000	1.00000	1.00000	0.99998	0.99994	1.00000	0.99998	1.00000
Defective Equipment	1.00000	0.99998	1.00000	1.00000	0.99996	0.99999	1.00000	1.00000	0.99996	0.99999
Foreign Interference	1.00000	0.99996	1.00000	1.00000	1.00000	0.99999	0.99999	0.99998	0.99999	1.00000
Human Element	1.00000	0.99999	1.00000	1.00000	1.00000	1.00000	1.00000	0.99999	1.00000	1.00000
Lightning	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Electrical	1.00000	1.00000	1.00000	0.99897	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Energy	1.00000	1.00000	0.99984	0.99993	0.99991	0.99972	0.99989	0.99996	0.99982	0.99983
Scheduled	0.99992	0.99998	0.99988	0.99999	0.99998	0.99999	0.99979	0.99985	1.00000	1.00000
Trees	1.00000	0.99999	1.00000	0.99998	1.00000

Yukon Electrical Company Limited
Outage Indices for Carcross and Tagish (2003-2012)
YUB-YECL-46(d) iii.

CARCROSS

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	1	-	-	-	-	-	-	-	-	-	1
Adverse Weather	-	2	-	3	-	1	3	1	1	-	11
Defective Equipment	-	-	-	1	1	2	1	2	2	2	11
Foreign Interference	3	-	1	1	1	-	1	2	2	1	12
Human Element	-	-	-	-	-	-	-	-	-	1	1
Lightning	-	-	1	-	-	-	-	-	-	-	1
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**2**	**1**	**2**	**7**	**7**	**2**	**5**	**-**	**26**
Scheduled	1	2	-	-	4	4	1	-	1	-	13
Trees	**-**	**8**	**-**	**-**	**-**	**3**	**2**	**3**	**-**	**-**	**16**
Unknown/Other	1	-	-	3	1	-	1	-	-	2	8
Total	**6**	**12**	**4**	**9**	**9**	**17**	**16**	**10**	**11**	**6**	**100**

TAGISH

NUMBER OF INTERRUPTIONS

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Adverse Environment	-	-	-	-	-	1	-	-	-	-	1
Adverse Weather	-	1	2	4	1	5	6	-	2	1	22
Defective Equipment	4	-	2	2	4	1	2	-	1	1	17
Foreign Interference	1	-	6	3	2	2	3	1	-	1	19
Human Element	-	-	-	-	1	-	1	-	-	-	2
Lightning	-	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**2**	**1**	**2**	**7**	**7**	**2**	**5**	**-**	**26**
Scheduled	4	-	-	2	3	7	2	1	-	3	22
Trees	**3**	**4**	**2**	**2**	**3**	**5**	**2**	**5**	**4**	**4**	**34**
Unknown/Other	-	-	-	2	2	1	-	-	-	-	5
Total	**12**	**5**	**14**	**16**	**18**	**29**	**23**	**9**	**12**	**10**	**148**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	0.01	-	3.04	-	0.01	1.04	0.00	0.07	-
Defective Equipment	-	-	-	0.04	0.00	0.01	1.03	0.03	1.04	0.01
Foreign Interference	0.07	-	0.11	0.00	0.00	-	0.08	0.02	0.01	0.00
Human Element	-	-	-	-	-	-	-	-	-	0.00
Lightning	-	-	0.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**1.03**	**1.62**	**2.00**	**7.28**	**7.24**	**2.05**	**5.16**	**-**
Scheduled	0.01	0.01	-	-	2.63	1.05	1.03	-	0.02	-
Trees	**-**	**6.32**	**-**	**-**	**-**	**2.09**	**0.01**	**4.81**	**-**	**-**
Unknown/Other	0.01	-	-	0.69	1.74	-	0.01	-	-	0.01
Total	**0.09**	**6.34**	**1.15**	**5.40**	**6.38**	**10.44**	**10.45**	**6.92**	**6.29**	**0.02**

SAIFI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	0.01	-	-	-	-
Adverse Weather	-	0.97	1.21	0.04	0.51	0.06	0.07	-	0.01	0.00
Defective Equipment	0.02	-	0.01	0.01	2.43	0.01	1.12	-	1.05	0.43
Foreign Interference	0.01	-	0.73	0.01	0.01	0.01	1.06	0.64	-	0.00
Human Element	-	-	-	-	0.01	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**1.04**	**1.08**	**2.00**	**7.16**	**7.38**	**2.11**	**5.18**	**-**
Scheduled	0.29	-	-	1.04	0.03	1.37	0.69	0.09	-	2.08
Trees	**1.00**	**2.44**	**0.60**	**0.38**	**0.32**	**3.65**	**1.18**	**0.45**	**0.11**	**2.43**
Unknown/Other	-	-	-	1.91	1.00	0.02	-	-	-	-
Total	**1.32**	**3.41**	**3.59**	**4.48**	**6.32**	**12.29**	**11.51**	**3.29**	**6.34**	**4.95**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	0.01	-	1.93	-	0.02	2.00	0.01	0.14	-
Defective Equipment	-	-	-	0.03	0.00	0.03	0.08	0.08	**4.74**	0.02
Foreign Interference	0.07	-	0.23	0.00	0.00	-	0.08	0.04	0.01	0.00
Human Element	-	-	-	-	-	-	-	-	-	0.02
Lightning	-	-	0.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**0.67**	**9.18**	**0.90**	**10.07**	**3.71**	**1.48**	**5.16**	**-**
Scheduled	0.00	0.02	-	-	4.45	2.50	2.41	-	0.03	-
Trees	**-**	**15.18**	**-**	**-**	**-**	**6.21**	**0.02**	**5.07**	**-**	**-**
Unknown/Other	0.00	-	-	1.27	1.30	-	0.02	-	-	0.08
Total	**0.08**	**15.21**	**0.90**	**12.40**	**6.66**	**18.83**	**8.33**	**6.68**	**10.08**	**0.12**

SAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	0.03	-	-	-	-
Adverse Weather	-	**7.52**	1.73	0.58	0.93	0.05	0.12	-	0.01	0.00
Defective Equipment	0.18	-	0.14	0.02	**5.70**	0.04	0.36	-	**4.80**	1.17
Foreign Interference	0.03	-	1.17	0.04	0.03	0.02	1.68	0.37	-	0.00
Human Element	-	-	-	-	0.01	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**0.68**	**6.28**	**0.90**	**9.93**	**3.78**	**1.55**	**5.10**	**-**
Scheduled	1.08	-	-	1.82	0.06	2.61	0.37	0.27	-	4.36
Trees	**3.08**	**23.09**	**2.24**	**2.80**	**0.89**	**17.23**	**1.73**	**0.73**	**1.68**	**20.86**
Unknown/Other	-	-	-	1.17	0.75	0.03	-	-	-	-
Total	**4.37**	**30.60**	**5.96**	**12.72**	**9.26**	**29.95**	**8.04**	**2.91**	**11.59**	**26.40**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	-	-	-	-	-
Adverse Weather	-	1.12	-	0.63	-	3.25	1.92	2.25	2.08	-
Defective Equipment	-	-	-	0.67	0.50	3.03	0.08	3.00	4.58	2.54
Foreign Interference	1.05	-	2.00	0.97	1.25	-	1.01	2.10	1.50	1.50
Human Element	-	-	-	-	-	-	-	-	-	5.13
Lightning	-	-	1.00	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**0.65**	**5.65**	**0.45**	**1.38**	**0.51**	**0.72**	**1.00**	**-**
Scheduled	0.40	1.47	-	-	1.69	2.38	2.33	-	1.83	-
Trees	**-**	**2.40**	**-**	**-**	**-**	**2.97**	**1.69**	**1.05**	**-**	**-**
Unknown/Other	0.30	-	-	1.83	0.75	-	1.50	-	-	13.17
Total	**0.92**	**2.40**	**0.78**	**2.30**	**1.04**	**1.80**	**0.80**	**0.97**	**1.60**	**6.34**

CAIDI

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Adverse Environment	-	-	-	-	-	3.25	-	-	-	-
Adverse Weather	-	7.75	1.43	13.25	1.83	0.90	1.67	-	2.38	1.25
Defective Equipment	11.73	-	9.16	2.00	2.35	6.75	0.32	-	4.58	2.70
Foreign Interference	2.08	-	1.62	3.05	1.75	2.00	1.58	0.58	-	1.33
Human Element	-	-	-	-	0.70	-	-	-	-	-
Lightning	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Electrical	-	-	-	-	-	-	-	-	-	-
Loss of Supply - Yukon Energy	**-**	**-**	**0.65**	**5.80**	**0.45**	**1.39**	**0.51**	**0.73**	**0.98**	**-**
Scheduled	3.70	-	-	1.76	1.72	1.90	0.53	2.93	-	2.10
Trees	**3.07**	**9.45**	**3.73**	**7.45**	**2.74**	**4.72**	**1.46**	**1.63**	**15.51**	**8.58**
Unknown/Other	-	-	-	0.61	0.75	2.00	-	-	-	-
Total	**3.30**	**8.97**	**1.66**	**2.84**	**1.47**	**2.44**	**0.70**	**0.89**	**1.83**	**5.34**

INDEX OF RELIABILITY

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	8760	8784	8760	8760	8760	8784	8760	8760	8760	8784
Adverse Environment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Adverse Weather	1.00000	1.00000	1.00000	0.99978	1.00000	1.00000	0.99977	1.00000	0.99998	1.00000
Defective Equipment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	0.99999	0.99999	0.99946	1.00000
Foreign Interference	0.99999	1.00000	0.99997	1.00000	1.00000	1.00000	0.99999	1.00000	1.00000	1.00000
Human Element	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Lightning	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Electrical	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Energy	**1.00000**	**1.00000**	**0.99992**	**0.99895**	**0.99990**	**0.99885**	**0.99958**	**0.99983**	**0.99941**	**1.00000**
Scheduled	1.00000	1.00000	1.00000	1.00000	0.99949	0.99972	0.99972	1.00000	1.00000	1.00000
Trees	**1.00000**	**0.99827**	**1.00000**	**1.00000**	**1.00000**	**0.99929**	**1.00000**	**0.99942**	**1.00000**	**1.00000**
Unknown/Other	1.00000	1.00000	1.00000	0.99986	0.99985	1.00000	1.00000	1.00000	1.00000	0.99999
Total	**0.99999**	**0.99827**	**0.99990**	**0.99858**	**0.99924**	**0.99786**	**0.99905**	**0.99924**	**0.99885**	**0.99999**

INDEX OF RELIABILITY

CEA Coding	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	8760	8784	8760	8760	8760	8784	8760	8760	8760	8784
Adverse Environment	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Adverse Weather	1.00000	0.99914	0.99980	0.99993	0.99989	0.99999	0.99999	1.00000	1.00000	1.00000
Defective Equipment	0.99998	1.00000	0.99998	1.00000	0.99935	1.00000	0.99996	1.00000	0.99945	0.99987
Foreign Interference	1.00000	1.00000	0.99987	0.99999	1.00000	1.00000	0.99981	0.99996	1.00000	1.00000
Human Element	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Lightning	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Electrical	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
Loss of Supply - Yukon Energy	**1.00000**	**1.00000**	**0.99992**	**0.99928**	**0.99990**	**0.99887**	**0.99957**	**0.99982**	**0.99942**	**1.00000**
Scheduled	0.99988	1.00000	1.00000	0.99979	0.99999	0.99970	0.99996	0.99997	1.00000	0.99950
Trees	**0.99965**	**0.99737**	**0.99974**	**0.99968**	**0.99990**	**0.99804**	**0.99980**	**0.99992**	**0.99981**	**0.99762**
Unknown/Other	1.00000	1.00000	1.00000	0.99987	0.99991	1.00000	1.00000	1.00000	1.00000	1.00000
Total	**0.99950**	**0.99652**	**0.99932**	**0.99855**	**0.99894**	**0.99659**	**0.99908**	**0.99967**	**0.99868**	**0.99699**

YUB-YECL-47

Reference: Destruction Bay Unit #2 Replacement, YECL Application, Business Case #14, page 2

Replace Unit #2 in Destruction Bay, which is at the end of its life, with a new diesel generator. Based on forecast load growth and Yukon Electrical's planning criteria, the new unit is planned to have similar generating capacity in comparison to the existing unit.

Request:

Please provide the size of the existing Unit #2 and the size of its proposed replacement.

Response:

The capacity of the current unit is 300kW; the proposed replacement, which the project estimate is based on, is also 300kW.

YUB-YECL-48

Reference: Automated Meter Reading – Whitehorse and area, YECL Application; Business Case #27, page 2 and 3

This project is to convert conventional electronic and mechanical meters to Automated Meter Reading (AMR) technology. The project will convert all meters in the Whitehorse area, Marsh Lake, Carcross, Tagish and Teslin communities to AMR technology, which is approximately 80% of all Yukon Electrical meters. The benefits of conversion will be improved customer service, improved safety performance for employees and customers and reduced vehicle emissions, as well as long term cost savings of over $2 million over 25 years as compared to conventional meter reading.

…

… the City [of Whitehorse] … is investigating the utilization of AMR technology to obtain water meter readings … there may be potential benefits to the project in terms of costs if the City chooses to partner with Yukon Electrical on the project.

Request:

(a) Please explain the difference between the terms “automated meter reading” (AMR) and “advanced metering infrastructure” (AMI).

(b) With respect to this AMR business case, please explain the significant changes since YECL’s last GRA that makes the project move viable and beneficial, and at the same addresses the concerns that were raised by interveners in YECL’s previous GRA.

(c) Please list and explain the potential benefits/economies if YECL were to partner with the City of Whitehorse respecting the AMR project — e.g. Does the crossover point shown on the *CPV of AMR Conventional Meters: Cost Comparison* (Business Case #27, Attachment 1, page 1 of 11) move to the left?

(d) Please explain if there are additional capital costs if YECL were to transition to AMI from AMR.

(e) Respecting the AMR meters that YECL is proposing to use, please explain the benefits of having the time-of-use ability built into the meter and the related costs.

i. If in the future the Board were to approve additional costs to enable time-of-use metering, please provide the additional asset-related costs and time that would be required to make the time-of-use metering benefits available to customers.

(j) Are the costs of equipping YECL's proposed Whistle Bend substation with a two-way automatic communication system (TWACS) built into the AMR business case?

(k) Has YECL had discussions or worked with YEC to review and assess the costs and potential benefits of the AMR project? Please provide a detailed explanation.

(l) Please explain what YECL is meaning respecting its submission that "there will be beneficial long-term cost savings." For example, are there any additional costs and time required in order to realize the long-term cost savings? Please explain.

(m) Please provide the cost/benefit analysis for this business case.

(n) Does the proposed AMR project enable YECL to provide time-of-use rates? If so, does YECL intend to apply for time-of-use rates? Have YECL customers requested time-of-use rates?

Response:

(a) Advanced Metering Infrastructure (AMI) are meters and systems that measure, collect, and analyze energy usage, and communicate with other devices within a customer's premise. Automated Meter Reading (AMR) is the communication system and meters that provide a reading of the energy usage at set and infrequent times.

(b) Significant changes since Yukon Electrical's last GRA filing that makes the project more viable and beneficial include:

(i) Reduction of implementation costs. Yukon Electrical has gained knowledge and experience from its affiliate company Northland Utilities (Yellowknife) Limited, which successfully implemented AMR in 2010 in a similar northern climate. NUY's implementation was completed under budget and in the forecast timeline. Yukon Electrical has

used information gathered by NUY during its implementation to better forecast implementation costs for this project.

(ii) Impact of regulation changes. New Measurement Canada regulations, which take effect January 1, 2014, will increase sample and testing work required on the existing mechanical meters. Measurement Canada will also be decreasing the life extensions of mechanical meters from six to four years. In comparison, AMR meters require testing after ten years.

Concerns raised during the previous GRA are addressed as follows:

Evidence of Reduction in Meter Reading Errors

Currently, Yukon Electrical experiences on average 60 questioned reads each month. The cost associated with sending someone to manually re-check these reads is approximately $50,400 per year. With the implementation of AMR, these costs as a result of human error are removed from the process.

In addition, AMR will also replace the need to send field staff to read meters when customers move or transfer accounts. Yukon Electrical averages 431 of these work order types per month. This equates to an annual cost savings of approximately $84,400.

Impact of Cost Overruns on AMR Project

The AMR project cost data has been further supported by the experiences of Northland Utilities (Yellowknife) Limited ("NUY"). NUY implemented the same infrastructure proposed by Yukon Electrical in 2010 and completed the project under budget. Through post-implementation discussions with NUY, Yukon Electrical is confident in its forecast outlined in the business case. Yukon Electrical has also built a contingency of 10% into the business case model. The proposed 9 year cross-over is a conservative estimate.

Work done with other Interveners

Yukon Electrical has engaged in meetings and discussions with both the City of Whitehorse and YEC on the proposed AMR project. Yukon Electrical supplied YEC with a copy of the proposed AMR business in March 2013, prior to submission of this filing. There are a small number

of YEC customers that can benefit from this project; therefore input on the overall project was not received.

(c) If a partnership was entered into with the City of Whitehorse respecting the AMR project, the City would fully contribute for their share of the hardware cost (capital) and billing components (O&M). The crossover point shown on the CPV of AMR Conventional Meters: Cost Comparison would become shorter as a percentage of installation labour would be allocated to any water meters installed.

(d) Yes, there would be significant additions to capital costs depending on the suite of AMI options selected. There are a number of different options within the context of Advanced Metering Infrastructure and each option would have separate costs. The single most significant cost would be the Meter Data Management System (MDMS) or similar technology that would collect, analyze and transfer data from the AMI meters to the ATCO CIS billing system. As ATCO Electric does not utilize AMI, this data system and technology would be fully incurred by Yukon Electrical to acquire and implement a new MDMS.

(e) The time of use (TOU) ability of the AMR meters Yukon Electrical is installing would be utilized to conduct load studies on the system. There is no additional cost for the meter as this is a built in capability of the Two Way Automatic Communication System (TWACS) meters. Currently, this TOU ability of the TWACS meter is not Measurement Canada approved for revenue metering. If the YUB were to enable TOU rates in the future, the costs could be substantial to implement if the TWACS meters were unable to obtain Measurement Canada approval. If Yukon Electrical was to proceed in selecting a different vendor then TWACS technology, we would lose out on our significant advantage that has been gained by adopting ATCO Electric's ("AE") AMR experience. AE has already developed a mature, stable and proven system. Yukon Electrical would need to incur costs to develop our own market technology research and pilot projects. Once a system was selected there would be additional costs associated with design, implementation and interfacing with Yukon Electrical's current billing (and other related) systems.

(j) TWACS is not needed at Whistle Bend Substation.

(k) Yes, Yukon Electrical has engaged in discussions with YEC regarding AMR. Additionally, a copy of the proposed AMR business case was provided to YEC. As the impact of AMR is minimal to YEC customers, further discussions did not arise.

(l) By stating "there will be beneficial long-term cost savings," Yukon Electrical is referring to the savings of more than $2.2 Million over the life of the project as shown in the Application in Business Case #27 – AMR Attachment 1. There are no additional costs and time required in order to realize the long-term cost savings. All costs have been included in the AMR Business Case #27 and supporting model to realize these savings.

(m) Please refer to YUB-YECL-48(m) Attachment 1 for a copy of the cost/benefit analysis for the AMR project which shows that customers will benefit from the implementation of AMR with cost savings in 9 years and cumulative savings of $2.2 million over 25 years.

(n) No, the proposed AMR meters do not currently have Measurement Canada approved revenue metering time of use ("TOU") capability.

Yukon Electrical does not intend on applying for TOU rates. Yukon Electrical examined the current electrical load profile of the area to be converted to AMR, there would be little to no beneficial result of implementing TOU rates.

The core purpose of TOU rates is to encourage consumers to shift electrical demand, rather than to reduce overall consumption. In the Yukon, and the AMR implementation area, the patterns of peak consumption closely align with the patterns of residential customer electrical use. Meaning, the peaks are associated with the residential customers' usage. These times of day are before and after work/school during the week. The peak times occur on the coldest days of the year, usually in December or January, when water flows are low. It can be assumed that, due to the load profile of residential customers influence on the peak, implementation of TOU rates would only shift load to a later hour rather than having an overall consumption reduction effect. Therefore, the consumption and associated peaks would still occur, just at a later hour, as residential heating and cooking would still be required regardless of price signals.

Yukon Electrical participated in a consultation workshop in January 2011 where electricity rates, as a driver for demand-side management (DSM), were discussed. Within the notes of the meeting, which can be found in UCG-YECL-128(a) Attachment 9, the participants had varying views on the benefits of TOU and the ability of a TOU program to be an effective tool for DSM.

The majority of North American jurisdictions which have converted to TOU rates did so through an outside directive. These rates were mandated either by act of provincial or state legislation change or a directive by the authorized regulatory

agency for that jurisdiction. Again, Yukon Electrical sees little benefit in TOU rates for the potential significant cost of implementing and will not be seeking TOU rates unless otherwise directed.

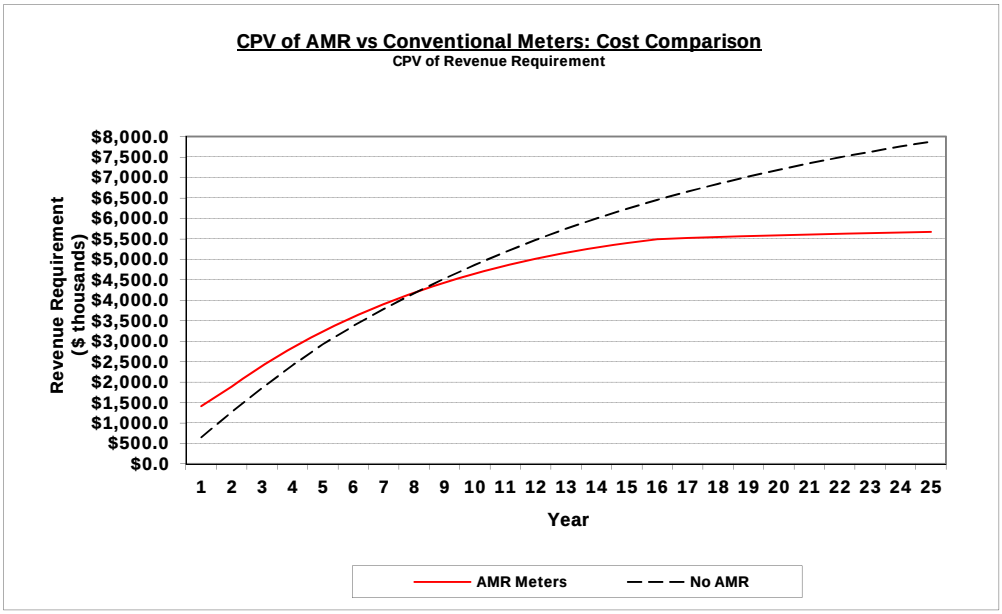
It should be noted that in the five-year DSM plan, coincidental peak savings are achieved through the proposed electricity conservation programs.

Cost Comparison: Yukon Electrical AMR Project

General Assumptions:
1. Analysis is over 25 years
2. AMR Implementation is over 2 years
3. Escalation Rate 2%
4. Analysis is on an incremental basis
5. Sunk capital costs are ignored
6. Future meter replacement costs are included

	AMR Meters	No AMR
Revenue Requirement		
CPV @ Year 5 *(thousands)*	**$3,237.6**	**$2,924.8**
CPV @ Year 25 *(thousands)*	**$5,669.9**	**$7,878.5**

2014/2015 Capital Cost Summary *(thousands)*	AMR Meters	No AMR
Generation Incremental		
Generation Existing		
Distribution	**$3,862.8**	**$307.1**
Transmission		
Total	**$3,862.8**	**$307.1**



Societal

Year	AMR Meters	No AMR
1	$1,407.3	$650.0
2	$1,883.7	$1,267.2
3	$2,388.6	$1,852.6
4	$2,838.0	$2,407.4
5	$3,237.6	$2,924.8
6	$3,592.5	$3,369.6
7	$3,907.4	$3,784.3
8	$4,186.3	$4,171.1
9	$4,433.2	$4,531.8
10	$4,651.3	$4,868.3
11	$4,843.6	$5,182.2
12	$5,012.9	$5,475.1
13	$5,161.6	$5,748.3
14	$5,292.0	$6,003.3
15	$5,401.4	$6,236.5
16	$5,490.6	$6,454.2
17	$5,522.2	$6,657.8
18	$5,545.2	$6,848.3
19	$5,566.8	$7,026.5
20	$5,587.0	$7,193.2
21	$5,605.8	$7,349.1
22	$5,623.5	$7,495.0
23	$5,640.0	$7,631.4
24	$5,655.5	$7,759.1
25	$5,669.9	$7,878.5

Assumptions: Yukon Electrical AMR Project
AMR Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.03248
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.04052
TOTALS		.	9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **7.13%**

D Escalation Rate **2.0%**

E US Exchange Rate **1.00**

F All analysis are based on 26 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis

H Total number of AMR Meters **14,482 YECL** 192,796

I Incremental Capital Cost: *All costs are inflated to the year that they occur.*

Input Starting Construction Year **Jan-14**

				Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
J	**METERS:**		Unit Cost	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40
	# of Residential Meters to be installed			6,343	6,560	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219
	# of Commercial Meters to be installed			0	1579	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
	# Spare Residential Meters	0%		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	# Spare Commerical Meters	0%		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Cost of Residential Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Cost of Residential AMR Module		$115.00 /meter	$729,445	$754,400	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225	$25,225
3	Cost of Commercial Meter		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Cost of Commercial AMR Module	=	$445.00 /meter	$0	$702,655	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540	$10,540
5	Installation - Residential Meters		$16.50 /meter	$104,660	$108,240	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619	$3,619
6	Installation - Commerical Meters		$205.00 /meter	$0	$323,695	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855	$4,855
7	Freight		$10.00 /meter	$63,430	$81,390	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430	$2,430
8	Billing System Configuration			$250,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Retrofitting Costs		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Meter Read Verification	5%	$36.00 /hr	$11,417	$14,650	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437	$437
12	Test Set & Spares Equipment			$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Contingency	10%		$117,895	$198,503.02	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711	$4,711
14	Project Management	5%		$58,947.60	$99,251.51	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$2,355	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal			$1,355,795	$2,282,785	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$54,174	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819	$51,819
K	**SUBSTATIONS:**																															
	# of Substations required			2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Aclara SCE materials			$160,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16	Installation by YECL			$35,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Contingency	10%		$19,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Project Management	5%		$9,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal			$224,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL Capital			**$1,580,045**	**$2,282,785**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$54,174**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**	**$51,819**
L	**Allocated AMR O&M Costs:** *includes contingency of* *25%*																															
19	O&M Acct#71212 - DCSI TNS Maintenance Support		$0.44 /meter	$0	$2,791	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582	$5,582
20	O&M Acct#71214 - Annual Sample Verification Process		$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	O&M Acct#72107 - I-Tek User Fees (Email & Server Stora		$0.13 /meter	$0	$823	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645	$1,645
22	O&M Acct#72109 - PCs & Monitors		$0.09 /meter	$0	$600	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201	$1,201
23	O&M Acct#72118 - I-Tek Support for TNS Server		$0.69 /meter	$0	$4,359	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719	$8,719
24	Labour Acct#71211 - AMR Meter Reading		$1.57 /meter	$0	$9,952	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905	$19,905
25	Labour Acct#71214 - AMR Verification		$0.03 /meter	$0	$206	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411	$411
26	Labour Acct#71215 - AMR Substation Troubleshoot & Sup		$0.71 /meter	$0	$4,504	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007	$9,007
27	Labour Acct# 71250 - AMR Special Meter Reading		$0.25 /meter	$0	$1,563	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126	$3,126
28	Conventional Meter Read Costs	100%	of existing costs	$689,400	$617,400	$76,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Affiliate Charges																															
	Subtotal			$689,400	$642,197	$126,395	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595	$49,595
M	**AMR O&M Savings / Revenue:**																															
29	Project Management			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Data-Cap Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Reduced Read-to-Bill Lag			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Manual Meter Reading Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	Meter Test Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Special Read Savings			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Labour Installation of Meters			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL O&M			**$689,400**	**$642,197**	**$126,395**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**	**$49,595**
	Total Cash Flow			**$2,269,445**	**$2,924,982**	**$180,568**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$103,768**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**	**$101,413**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$729,445	$754,400	$26,244	$26,769	$27,305	$27,851	$28,408	$28,976	$29,556	$30,147	$30,750	$31,365	$31,992	$32,632	$33,284	$33,950	$34,629	$35,322	$36,028	$36,749	$37,484	$38,233	$38,998	$39,778	$40,573	$41,385	$42,213
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$702,655	$10,966	$11,185	$11,409	$11,637	$11,870	$12,107	$12,349	$12,596	$12,848	$13,105	$13,367	$13,634	$13,907	$14,185	$14,469	$14,758	$15,053	$15,355	$15,662	$15,975	$16,294	$16,620	$16,953	$17,292	$17,638
$104,660	$108,240	$3,766	$3,841	$3,918	$3,996	$4,076	$4,157	$4,241	$4,325	$4,412	$4,500	$4,590	$4,682	$4,776	$4,871	$4,969	$5,068	$5,169	$5,273	$5,378	$5,486	$5,595	$5,707	$5,821	$5,938	$6,057
$0	$323,695	$5,052	$5,153	$5,256	$5,361	$5,468	$5,577	$5,689	$5,803	$5,919	$6,037	$6,158	$6,281	$6,407	$6,535	$6,665	$6,799	$6,935	$7,073	$7,215	$7,359	$7,506	$7,657	$7,810	$7,966	$8,125
$63,430	$81,390	$2,529	$2,579	$2,631	$2,683	$2,737	$2,792	$2,848	$2,905	$2,963	$3,022	$3,082	$3,144	$3,207	$3,271	$3,336	$3,403	$3,471	$3,541	$3,611	$3,684	$3,757	$3,832	$3,909	$3,987	$4,067
$250,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$11,417	$14,650	$455	$464	$474	$483	$493	$503	$513	$523	$533	$544	$555	$566	$577	$589	$601	$613	$625	$637	$650	$663	$676	$690	$704	$718	$732
$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$117,895	$198,503	$4,901	$4,999	$5,099	$5,201	$5,305	$5,411	$5,519	$5,630	$5,742	$5,857	$5,974	$6,094	$6,216	$6,340	$6,467	$6,596	$6,728	$6,863	$7,000	$7,140	$7,283	$7,428	$7,577	$7,729	$7,883
$58,948	$99,252	$2,451	$2,500	$2,550	$2,601	$2,653	$2,706	$2,760	$2,815	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,355,795	$2,282,785	$56,363	$57,490	$58,640	$59,812	$61,009	$62,229	$63,473	$64,743	$63,166	$64,430	$65,718	$67,033	$68,373	$69,741	$71,136	$72,558	$74,010	$75,490	$77,000	$78,540	$80,110	$81,713	$83,347	$85,014	$86,714
$160,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$35,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$19,500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$9,750	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$224,250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$1,580,045	$2,328,440	$56,363	$57,490	$58,640	$59,812	$61,009	$62,229	$63,473	$64,743	$63,166	$64,430	$65,718	$67,033	$68,373	$69,741	$71,136	$72,558	$74,010	$75,490	$77,000	$78,540	$80,110	$81,713	$83,347	$85,014	$86,714
$0	$2,847	$5,807	$5,923	$6,042	$6,163	$6,286	$6,412	$6,540	$6,671	$6,804	$6,940	$7,079	$7,221	$7,365	$7,512	$7,663	$7,816	$7,972	$8,132	$8,294	$8,460	$8,629	$8,802	$8,978	$9,158	$9,341
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$839	$1,711	$1,746	$1,781	$1,816	$1,853	$1,890	$1,927	$1,966	$2,005	$2,045	$2,086	$2,128	$2,171	$2,214	$2,258	$2,303	$2,349	$2,396	$2,444	$2,493	$2,543	$2,594	$2,646	$2,699	$2,753
$0	$612	$1,249	$1,274	$1,300	$1,326	$1,352	$1,379	$1,407	$1,435	$1,464	$1,493	$1,523	$1,553	$1,584	$1,616	$1,649	$1,681	$1,715	$1,749	$1,784	$1,820	$1,856	$1,894	$1,931	$1,970	$2,010
$0	$4,446	$9,071	$9,252	$9,437	$9,626	$9,818	$10,015	$10,215	$10,419	$10,628	$10,840	$11,057	$11,278	$11,504	$11,734	$11,969	$12,208	$12,452	$12,701	$12,955	$13,214	$13,479	$13,748	$14,023	$14,304	$14,590
$0	$10,151	$20,709	$21,123	$21,545	$21,976	$22,416	$22,864	$23,321	$23,788	$24,264	$24,749	$25,244	$25,749	$26,264	$26,789	$27,325	$27,871	$28,429	$28,997	$29,577	$30,169	$30,772	$31,387	$32,015	$32,656	$33,309
$0	$210	$428	$436	$445	$454	$463	$472	$482	$491	$501	$511	$522	$532	$543	$553	$565	$576	$587	$599	$611	$623	$636	$649	$661	$675	$688
$0	$4,594	$9,371	$9,558	$9,750	$9,945	$10,143	$10,346	$10,553	$10,764	$10,980	$11,199	$11,423	$11,652	$11,885	$12,122	$12,365	$12,612	$12,864	$13,122	$13,384	$13,652	$13,925	$14,203	$14,487	$14,777	$15,073
$0	$1,594	$3,252	$3,317	$3,383	$3,451	$3,520	$3,590	$3,662	$3,735	$3,810	$3,886	$3,964	$4,043	$4,124	$4,207	$4,291	$4,376	$4,464	$4,553	$4,644	$4,737	$4,832	$4,929	$5,027	$5,128	$5,230
$689,400	$629,748	$79,903	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$655,041	$131,501	$52,630	$53,683	$54,756	$55,852	$56,969	$58,108	$59,270	$60,455	$61,665	$62,898	$64,156	$65,439	$66,748	$68,083	$69,444	$70,833	$72,250	$73,695	$75,169	$76,672	$78,206	$79,770	$81,365	$82,992
$2,269,445	$2,983,482	$187,863	$110,120	$112,322	$114,569	$116,860	$119,197	$121,581	$124,013	$123,622	$126,094	$128,616	$131,189	$133,812	$136,489	$139,218	$142,003	$144,843	$147,740	$150,694	$153,708	$156,783	$159,918	$163,117	$166,379	$169,706

Assumptions: Yukon Electrical AMR Project
Conventional Meter Cost Impact

A Distribution Incremental Capital Structure and Cost

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	**5.800%**	**56.00%**	0.0325	0.0325
Preferred	**0.000%**	**0.00%**	0.0000	0.0000
Common	**9.210%**	**44.00%**	0.0579	0.0405
TOTALS			9.037%	7.300%

B Income Taxes **30.00%**

C Depreciation Rates: **8.09%**

D Escalation Rate **2.0%**

E US Exchange Rate **1**

F All analysis are based on 25 years of costs.

G Embedded distribution capital and O&M costs are not considered in analysis.

H Incremental Capital Cost:

Input Starting Construction Year **Jan-14**

	Unit Cost	Year 0 Jan-14	Year 1 Jan-15	Year 2 Jan-16	Year 3 Jan-17	Year 4 Jan-18	Year 5 Jan-19	Year 6 Jan-20	Year 7 Jan-21	Year 8 Jan-22	Year 9 Jan-23	Year 10 Jan-24	Year 11 Jan-25	Year 12 Jan-26	Year 13 Jan-27	Year 14 Jan-28	Year 15 Jan-29	Year 16 Jan-30	Year 17 Jan-31	Year 18 Jan-32	Year 19 Jan-33	Year 20 Jan-34	Year 21 Jan-35	Year 22 Jan-36	Year 23 Jan-37	Year 24 Jan-38	Year 25 Jan-39	Year 26 Jan-40	Year 27 Jan-41	Year 28 Jan-42
# of Residential Meters to be installed/replaced		1,850	1,850	1,850	1,850	1,850	1,850	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
# of Commercial Meters to be installed/replaced		150	150	150	150	150	150	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
1 Cost of Residential Meter	$35.00 /meter	$64,750	$64,750	$64,750	$64,750	$64,750	$64,750	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000	$14,000
2 Cost of Commercial Meter	$200.00 /meter	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
3 Installation - Residential Meters	$16.50 /meter	$30,525	$30,525	$30,525	$30,525	$30,525	$30,525	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600	$6,600
4 Installation - Commerical Meters	$55.00 /meter	$8,250	$8,250	$8,250	$8,250	$8,250	$8,250	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750	$2,750
5 Freight Cost (in CDN)	$10.00 /meter	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500	$4,500
6 Residential Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Commerical Meter Salvage (credit)	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Retrofitting Costs	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Meter Read Verification	$0.00 /meter	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$153,525	$153,525	$153,525	$153,525	$153,525	$153,525	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850	$37,850
TOTAL Capital		**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$153,525**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**	**$37,850**
I **Conventional O&M Costs:**																														
1 Manual Meter Reading Costs		$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800	$460,800
2 Meter Test Costs	$36.40 /meter	$72,800	$72,800	$72,800	$72,800	$72,800	$72,800	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380	$16,380
3 Customer Applications & Service Orders		$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000	$135,000
4 Data Cap Costs		$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800	$20,800
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8																														
9																														
TOTAL O&M		**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$689,400**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,980**	**$632,982**	**$632,984**
Total Cash Flow		**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$842,925**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,830**	**$670,832**	**$670,834**

Inflated Costs

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41	Jan-42
$64,750	$66,045	$67,366	$68,713	$70,087	$71,489	$15,766	$16,082	$16,403	$16,731	$17,066	$17,407	$17,755	$18,110	$18,473	$18,842	$19,219	$19,603	$19,995	$20,395	$20,803	$21,219	$21,644	$22,077	$22,518	$22,968	$23,428	$23,896	$24,374
$30,000	$30,600	$31,212	$31,836	$32,473	$33,122	$11,262	$11,487	$11,717	$11,951	$12,190	$12,434	$12,682	$12,936	$13,195	$13,459	$13,728	$14,002	$14,282	$14,568	$14,859	$15,157	$15,460	$15,769	$16,084	$16,406	$16,734	$17,069	$17,410
$30,525	$31,136	$31,758	$32,393	$33,041	$33,702	$7,433	$7,581	$7,733	$7,888	$8,045	$8,206	$8,370	$8,538	$8,709	$8,883	$9,060	$9,242	$9,426	$9,615	$9,807	$10,003	$10,203	$10,408	$10,616	$10,828	$11,045	$11,265	$11,491
$8,250	$8,415	$8,583	$8,755	$8,930	$9,109	$3,097	$3,159	$3,222	$3,287	$3,352	$3,419	$3,488	$3,557	$3,629	$3,701	$3,775	$3,851	$3,928	$4,006	$4,086	$4,168	$4,251	$4,336	$4,423	$4,512	$4,602	$4,694	$4,788
$20,000	$20,400	$20,808	$21,224	$21,649	$22,082	$5,068	$5,169	$5,272	$5,378	$5,485	$5,595	$5,707	$5,821	$5,938	$6,056	$6,178	$6,301	$6,427	$6,556	$6,687	$6,820	$6,957	$7,096	$7,238	$7,383	$7,530	$7,681	$7,835
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$153,525	$156,596	$159,727	$162,922	$166,180	$169,504	$42,625	$43,478	$44,347	$45,234	$46,139	$47,062	$48,003	$48,963	$49,942	$50,941	$51,960	$52,999	$54,059	$55,140	$56,243	$57,368	$58,515	$59,686	$60,879	$62,097	$63,339	$64,606	$65,898
$153,525	$156,596	$159,727	$162,922	$166,180	$169,504	$42,625	$43,478	$44,347	$45,234	$46,139	$47,062	$48,003	$48,963	$49,942	$50,941	$51,960	$52,999	$54,059	$55,140	$56,243	$57,368	$58,515	$59,686	$60,879	$62,097	$63,339	$64,606	$65,898
$460,800	$470,016	$479,416	$489,005	$498,785	$508,760	$518,936	$529,314	$539,901	$550,699	$561,713	$572,947	$584,406	$596,094	$608,016	$620,176	$632,580	$645,231	$658,136	$671,299	$684,725	$698,419	$712,387	$726,635	$741,168	$755,991	$771,111	$786,533	$802,264
$72,800	$74,256	$75,741	$77,256	$78,801	$80,377	$18,447	$18,815	$19,192	$19,576	$19,967	$20,366	$20,774	$21,189	$21,613	$22,045	$22,486	$22,936	$23,395	$23,863	$24,340	$24,827	$25,323	$25,830	$26,346	$26,873	$27,411	$27,959	$28,518
$135,000	$137,700	$140,454	$143,263	$146,128	$149,051	$152,032	$155,073	$158,174	$161,337	$164,564	$167,856	$171,213	$174,637	$178,130	$181,692	$185,326	$189,033	$192,813	$196,670	$200,603	$204,615	$208,707	$212,881	$217,139	$221,482	$225,911	$230,430	$235,038
$20,800	$21,216	$21,640	$22,073	$22,515	$22,965	$23,424	$23,893	$24,371	$24,858	$25,355	$25,862	$26,379	$26,907	$27,445	$27,994	$28,554	$29,125	$29,708	$30,302	$30,908	$31,526	$32,156	$32,800	$33,455	$34,125	$34,807	$35,503	$36,213
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$689,400	$703,188	$717,252	$731,597	$746,229	$761,153	$712,838	$727,095	$741,637	$756,470	$771,599	$787,031	$802,772	$818,827	$835,204	$851,908	$868,946	$886,325	$904,051	$922,132	$940,575	$959,386	$978,574	$998,146	$1,018,109	######	$1,059,240	$1,080,428	$1,102,040
$842,925	$859,784	$876,979	$894,519	$912,409	$930,657	$755,464	$770,573	$785,984	$801,704	$817,738	$834,093	$850,775	$867,790	$885,146	$902,849	$920,906	$939,324	$958,110	$977,273	$996,818	######	$1,037,090	######	$1,078,988	######	$1,122,579	$1,145,034	$1,167,938

Yukon Electrical AMR Project
AMR Cost Impact

	Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
	REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	METERS:																												
1	Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Cost of Residential AMR Module	364,723	741,923	377,200	13,122	13,385	13,652	13,925	14,204	14,488	14,778	15,073	15,375	15,682	15,996	16,316	16,642	16,975	17,315	17,661	18,014	18,374	18,742	19,117	19,499	19,889	20,287	20,692	21,106
3	Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Cost of Commercial AMR Module	0	351,328	351,328	5,483	5,592	5,704	5,818	5,935	6,053	6,175	6,298	6,424	6,552	6,684	6,817	6,954	7,093	7,234	7,379	7,527	7,677	7,831	7,987	8,147	8,310	8,476	8,646	8,819
5	Installation - Residential Meters	52,330	106,450	54,120	1,883	1,920	1,959	1,998	2,038	2,079	2,120	2,163	2,206	2,250	2,295	2,341	2,388	2,436	2,484	2,534	2,585	2,636	2,689	2,743	2,798	2,854	2,911	2,969	3,028
6	Installation - Commerical Meters	0	161,848	161,848	2,526	2,576	2,628	2,680	2,734	2,789	2,844	2,901	2,959	3,019	3,079	3,141	3,203	3,267	3,333	3,399	3,467	3,537	3,607	3,680	3,753	3,828	3,905	3,983	4,063
7	Freight	31,715	72,410	40,695	1,264	1,290	1,315	1,342	1,368	1,396	1,424	1,452	1,481	1,511	1,541	1,572	1,603	1,635	1,668	1,702	1,736	1,770	1,806	1,842	1,879	1,916	1,955	1,994	2,034
8	Billing System Configuration	125,000	125,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Meter Read Verification	5,709	13,034	7,325	228	232	237	241	246	251	256	261	267	272	277	283	289	294	300	306	312	319	325	332	338	345	352	359	366
12	Test Set & Spares Equipment	10,000	10,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Contingency	58,948	158,199	99,252	2,451	2,500	2,550	2,601	2,653	2,706	2,760	2,815	2,871	2,929	2,987	3,047	3,108	3,170	3,233	3,298	3,364	3,431	3,500	3,570	3,641	3,714	3,788	3,864	3,942
14	Project Management	29,474	79,100	49,626	1,225	1,250	1,275	1,300	1,326	1,353	1,380	1,407	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Aclara SCE materials	80,000	80,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Installation by YECL	17,500	17,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Contingency	9,750	9,750	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Project Management	4,875	4,875	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Capital	790,022	1,931,415	1,141,392	28,181	28,745	29,320	29,906	30,504	31,114	31,737	32,371	31,583	32,215	32,859	33,516	34,187	34,870	35,568	36,279	37,005	37,745	38,500	39,270	40,055	40,856	41,673	42,507	43,357
	Operations & Maintenance:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	Allocated AMR O&M Costs:																												
19	O&M Acct#71212 - DCSI TNS Maintenanc	0	2,847	5,807	5,923	6,042	6,163	6,286	6,412	6,540	6,671	6,804	6,940	7,079	7,221	7,365	7,512	7,663	7,816	7,972	8,132	8,294	8,460	8,629	8,802	8,978	9,158	0	0
20	O&M Acct#71214 - Annual Sample Verifica	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	O&M Acct#72107 - I-Tek User Fees (Emai	0	839	1,711	1,746	1,781	1,816	1,853	1,890	1,927	1,966	2,005	2,045	2,086	2,128	2,171	2,214	2,258	2,303	2,349	2,396	2,444	2,493	2,543	2,594	2,646	2,699	0	0
22	O&M Acct#72109 - PCs & Monitors	0	612	1,249	1,274	1,300	1,326	1,352	1,379	1,407	1,435	1,464	1,493	1,523	1,553	1,584	1,616	1,649	1,681	1,715	1,749	1,784	1,820	1,856	1,894	1,931	1,970	0	0
23	O&M Acct#72118 - I-Tek Support for TNS	0	4,446	9,071	9,252	9,437	9,626	9,818	10,015	10,215	10,419	10,628	10,840	11,057	11,278	11,504	11,734	11,969	12,208	12,452	12,701	12,955	13,214	13,479	13,748	14,023	14,304	0	0
24	Labour Acct#71211 - AMR Meter Reading	0	10,151	20,709	21,123	21,545	21,976	22,416	22,864	23,321	23,788	24,264	24,749	25,244	25,749	26,264	26,789	27,325	27,871	28,429	28,997	29,577	30,169	30,772	31,387	32,015	32,656	0	0
25	Labour Acct#71214 - AMR Verification	0	210	428	436	445	454	463	472	482	491	501	511	522	532	543	553	565	576	587	599	611	623	636	649	661	675	0	0
26	Labour Acct#71215 - AMR Substation Tro	0	4,594	9,371	9,558	9,750	9,945	10,143	10,346	10,553	10,764	10,980	11,199	11,423	11,652	11,885	12,122	12,365	12,612	12,864	13,122	13,384	13,652	13,925	14,203	14,487	14,777	0	0
27	Labour Acct# 71250 - AMR Special Meter	0	1,594	3,252	3,317	3,383	3,451	3,520	3,590	3,662	3,735	3,810	3,886	3,964	4,043	4,124	4,207	4,291	4,376	4,464	4,553	4,644	4,737	4,832	4,929	5,027	5,128	0	0
28	Conventional Meter Read Costs	689,400	629,748	79,903	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Affiliate Charges	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	AMR O&M Savings / Revenue:																												
29	Project Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Data-Cap Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Reduced Read-to-Bill Lag	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Manual Meter Reading Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total O&M	689,400	655,041	131,501	52,630	53,683	54,756	55,852	56,969	58,108	59,270	60,455	61,665	62,898	64,156	65,439	66,748	68,083	69,444	70,833	72,250	73,695	75,169	76,672	78,206	79,770	81,365	0	0

Yukon Electrical AMR Project
AMR Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:																												
Cost of Residential Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	7.130%	26,005	78,904	105,798	106,734	107,688	108,662	109,654	110,667	111,700	112,754	113,829	114,925	116,043	117,183	118,347	118,779	16,999	17,339	17,685	18,039	18,400	18,768	19,143	19,526	19,917	20,315	20,721
Cost of Commercial Meter	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	7.130%	0	25,050	50,099	50,490	50,889	51,296	51,711	52,134	52,565	53,006	53,455	53,913	54,380	54,856	55,342	55,838	25,720	7,245	7,389	7,537	7,688	7,842	7,999	8,159	8,322	8,488	8,658
Installation - Residential Meters	7.130%	3,731	11,321	15,180	15,314	15,451	15,591	15,733	15,878	16,027	16,178	16,332	16,489	16,650	16,813	16,980	17,042	2,439	2,488	2,537	2,588	2,640	2,693	2,747	2,802	2,858	2,915	2,973
Installation - Commerical Meters	7.130%	0	11,540	23,079	23,260	23,443	23,631	23,822	24,017	24,215	24,418	24,625	24,836	25,051	25,271	25,495	25,723	11,848	3,337	3,404	3,472	3,542	3,612	3,685	3,758	3,834	3,910	3,988
Freight	7.130%	2,261	7,424	10,326	10,416	10,508	10,602	10,697	10,795	10,894	10,996	11,099	11,205	11,313	11,423	11,535	11,649	1,990	1,671	1,704	1,738	1,773	1,808	1,844	1,881	1,919	1,957	1,996
Billing System Configuration	7.130%	8,913	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	17,825	9,362	0	0	0	0	0	0	0	0	0	0	0
0	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	7.130%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	7.130%	407	1,336	1,859	1,875	1,891	1,908	1,925	1,943	1,961	1,979	1,998	2,017	2,036	2,056	2,076	2,097	358	301	307	313	319	325	332	339	345	352	359
Test Set & Spares Equipment	7.130%	713	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	1,426	749	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	4,203	15,483	22,559	22,734	22,912	23,094	23,279	23,468	23,661	23,858	24,059	24,264	24,472	24,685	24,903	24,960	3,174	3,238	3,303	3,369	3,436	3,505	3,575	3,646	3,719	3,794	3,870
Project Management	7.130%	2,101	7,741	11,280	11,367	11,456	11,547	11,640	11,734	11,831	11,929	12,029	12,029	12,029	12,029	12,029	5,942	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:																												
Aclara SCE materials	7.130%	5,704	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	11,408	5,992	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	7.130%	1,248	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	1,311	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	7.130%	695	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	730	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	7.130%	348	695	695	695	695	695	695	695	695	695	695	695	695	695	365	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		56,329	194,038	275,420	277,429	279,479	281,569	283,701	285,876	288,095	290,358	292,666	294,918	297,215	299,557	285,216	262,030	62,529	35,618	36,330	37,057	37,798	38,554	39,325	40,111	40,913	41,732	42,566

ACCUMULATED DEPRECIATION:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	26,005	104,909	210,707	317,440	425,129	533,790	643,444	754,112	865,812	978,565	1,092,394	1,207,319	1,323,362	1,440,545	1,558,892	1,677,670	1,694,669	1,712,008	1,729,693	1,747,732	1,766,132	1,784,900	1,804,044	1,823,570	1,843,487	1,863,802	1,884,523
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	25,050	75,149	125,639	176,528	227,824	279,534	331,668	384,233	437,239	490,694	544,606	598,986	653,842	709,185	765,023	790,743	797,987	805,377	812,914	820,602	828,444	836,442	844,601	852,923	861,411	870,069
Installation - Residential Meters	0	3,731	15,052	30,232	45,546	60,997	76,587	92,320	108,199	124,225	140,403	156,735	173,224	189,874	206,687	223,667	240,709	243,148	245,636	248,173	250,762	253,402	256,094	258,841	261,643	264,500	267,415	270,388
Installation - Commerical Meters	0	0	11,540	34,619	57,879	81,322	104,953	128,774	152,791	177,006	201,425	226,050	250,886	275,937	301,208	326,703	352,426	364,275	367,612	371,016	374,488	378,030	381,643	385,327	389,086	392,919	396,830	400,818
Freight	0	2,261	9,685	20,011	30,427	40,935	51,536	62,233	73,028	83,922	94,918	106,018	117,223	128,535	139,958	151,493	163,142	165,132	166,802	168,506	170,244	172,017	173,825	175,670	177,551	179,470	181,427	183,424
Billing System Configuration	0	8,913	26,738	44,563	62,388	80,213	98,038	115,863	133,688	151,513	169,338	187,163	204,988	222,813	240,638	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	407	1,743	3,602	5,477	7,368	9,277	11,202	13,145	15,106	17,085	19,083	21,100	23,136	25,192	27,269	29,365	29,724	30,024	30,331	30,644	30,963	31,289	31,620	31,959	32,305	32,657	33,016
Test Set & Spares Equipment	0	713	2,139	3,565	4,991	6,417	7,843	9,269	10,695	12,121	13,547	14,973	16,399	17,825	19,251	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Contingency	0	4,203	19,686	42,245	64,979	87,891	110,985	134,264	157,732	181,394	205,252	229,311	253,574	278,047	302,732	327,635	352,595	355,769	359,007	362,310	365,678	369,115	372,619	376,194	379,841	383,560	387,354	391,224
Project Management	0	2,101	9,843	21,122	32,489	43,945	55,492	67,132	78,866	90,697	102,626	114,655	126,685	138,714	150,744	162,773	168,716	168,716	168,716	168,716	168,716	168,716	168,716	168,716	168,716	168,716	168,716	168,716
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	5,704	17,112	28,520	39,928	51,336	62,744	74,152	85,560	96,968	108,376	119,784	131,192	142,600	154,008	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000	160,000
Installation by YECL	0	1,248	3,743	6,239	8,734	11,230	13,725	16,221	18,716	21,212	23,707	26,203	28,698	31,194	33,689	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Contingency	0	695	2,086	3,476	4,866	6,257	7,647	9,037	10,428	11,818	13,208	14,599	15,989	17,379	18,770	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Project Management	0	348	1,043	1,738	2,433	3,128	3,823	4,519	5,214	5,909	6,604	7,299	7,995	8,690	9,385	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750	9,750
		56,329	250,367	525,787	803,216	1,082,694	1,364,263	1,647,965	1,933,841	2,221,936	2,512,294	2,804,959	3,099,877	3,397,091	3,696,649	3,981,865	4,243,895	4,306,424	4,342,042	4,378,372	4,415,428	4,453,226	4,491,780	4,531,104	4,571,216	4,612,129	4,653,861	4,696,427

PROPERTY IN SERVICE (beg yr):	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
METERS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Residential AMR Module	0	364,723	1,080,640	1,378,936	1,286,261	1,192,911	1,098,876	1,004,140	908,689	812,510	715,588	617,907	519,454	420,211	320,164	219,297	117,592	15,788	16,104	16,426	16,755	17,090	17,432	17,780	18,136	18,499	18,869	19,246
Cost of Commercial Meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cost of Commercial AMR Module	0	0	351,328	677,605	632,989	588,091	542,906	497,429	451,653	405,573	359,182	312,475	265,444	218,084	170,388	122,349	73,960	25,214	6,729	6,863	7,001	7,141	7,283	7,429	7,578	7,729	7,884	8,042
Installation - Residential Meters	0	52,330	155,048	197,847	184,550	171,157	157,665	144,072	130,377	116,578	102,671	88,656	74,530	60,291	45,937	31,464	16,872	2,265	2,311	2,357	2,404	2,452	2,501	2,551	2,602	2,654	2,707	2,761
Installation - Commerical Meters	0	0	161,848	312,155	291,602	270,918	250,103	229,153	208,065	186,837	165,466	143,949	122,283	100,466	78,493	56,363	34,071	11,616	3,100	3,162	3,225	3,290	3,355	3,422	3,491	3,561	3,632	3,705
Freight	0	31,715	101,864	135,135	126,073	116,947	107,755	98,495	89,166	79,767	70,297	60,753	51,135	41,441	31,669	21,819	11,887	1,874	1,552	1,583	1,614	1,647	1,680	1,713	1,747	1,782	1,818	1,854
Billing System Configuration	0	125,000	241,088	223,263	205,438	187,613	169,788	151,963	134,138	116,313	98,488	80,663	62,838	45,013	27,188	9,363	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofitting Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Read Verification	0	5,709	18,335	24,324	22,693	21,050	19,396	17,729	16,050	14,358	12,653	10,936	9,204	7,459	5,700	3,927	2,140	337	279	285	291	296	302	308	315	321	327	334
Test Set & Spares Equipment	0	10,000	19,287	17,861	16,435	15,009	13,583	12,157	10,731	9,305	7,879	6,453	5,027	3,601	2,175	749	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	58,948	212,944	296,713	276,604	256,370	236,007	215,514	194,887	174,124	153,222	132,179	110,992	89,657	68,171	46,533	24,738	2,949	3,007	3,068	3,129	3,192	3,255	3,321	3,387	3,455	3,524	3,594
Project Management	0	29,474	106,472	148,356	138,302	128,185	118,004	107,757	97,443	87,062	76,611	66,090	54,060	42,031	30,001	17,972	5,942	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUBSTATIONS:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aclara SCE materials	0	80,000	154,296	142,888	131,480	120,072	108,664	97,256	85,848	74,440	63,032	51,624	40,216	28,808	17,400	5,992	0	0	0	0	0	0	0	0	0	0	0	0
Installation by YECL	0	17,500	33,752	31,257	28,761	26,266	23,770	21,275	18,779	16,284	13,788	11,293	8,797	6,302	3,806	1,311	0	0	0	0	0	0	0	0	0	0	0	0
Contingency	0	9,750	18,805	17,414	16,024	14,634	13,243	11,853	10,463	9,072	7,682	6,292	4,901	3,511	2,121	730	0	0	0	0	0	0	0	0	0	0	0	0
Project Management	0	4,875	9,402	8,707	8,012	7,317	6,622	5,927	5,231	4,536	3,841	3,146	2,451	1,755	1,060	365	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	790,022	2,665,108	3,612,462	3,365,224	3,116,540	2,866,381	2,614,718	2,361,521	2,106,759	1,850,401	1,592,415	1,331,332	1,068,629	804,274	538,233	287,204	60,044	33,083	33,744	34,419	35,107	35,810	36,526	37,256	38,001	38,761	39,537

Yukon Electrical AMR Project
AMR Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	30.000%		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	689,400	689,400	0	(689,400)	(689,400)	0
1	Jan-15	790,022	57,675	56,329	13,721	655,041	782,765	0	(782,765)	(1,407,289)	1
2	Jan-16	2,665,108	194,564	194,038	46,286	131,501	566,389	0	(566,389)	(1,883,682)	2
3	Jan-17	3,612,462	263,724	275,420	62,739	52,630	654,513	0	(654,513)	(2,388,570)	3
4	Jan-18	3,365,224	245,675	277,429	58,445	53,683	635,232	0	(635,232)	(2,837,972)	4
5	Jan-19	3,116,540	227,520	279,479	54,126	54,756	615,881	0	(615,881)	(3,237,571)	5
6	Jan-20	2,866,381	209,257	281,569	49,782	55,852	596,460	0	(596,460)	(3,592,494)	6
7	Jan-21	2,614,718	190,885	283,701	45,411	56,969	576,966	0	(576,966)	(3,907,362)	7
8	Jan-22	2,361,521	172,400	285,876	41,014	58,108	557,398	0	(557,398)	(4,186,340)	8
9	Jan-23	2,106,759	153,802	288,095	36,589	59,270	537,756	0	(537,756)	(4,433,180)	9
10	Jan-24	1,850,401	135,087	290,358	32,137	60,455	518,036	0	(518,036)	(4,651,260)	10
11	Jan-25	1,592,415	116,253	292,666	27,656	61,665	498,239	0	(498,239)	(4,843,621)	11
12	Jan-26	1,331,332	97,193	294,918	23,122	62,898	478,130	0	(478,130)	(5,012,920)	12
13	Jan-27	1,068,629	78,014	297,215	18,559	64,156	457,944	0	(457,944)	(5,161,631)	13
14	Jan-28	804,274	58,715	299,557	13,968	65,439	437,680	0	(437,680)	(5,291,982)	14
15	Jan-29	538,233	39,293	285,216	9,348	66,748	400,605	0	(400,605)	(5,401,403)	15
16	Jan-30	287,204	20,967	262,030	4,988	68,083	356,068	0	(356,068)	(5,490,598)	16
17	Jan-31	60,044	4,383	62,529	1,043	69,444	137,400	0	(137,400)	(5,522,164)	17
18	Jan-32	33,083	2,415	35,618	575	70,833	109,441	0	(109,441)	(5,545,223)	18
19	Jan-33	33,744	2,463	36,330	586	72,250	111,629	0	(111,629)	(5,566,793)	19
20	Jan-34	34,419	2,513	37,057	598	73,695	113,862	0	(113,862)	(5,586,972)	20
21	Jan-35	35,107	2,563	37,798	610	75,169	116,139	0	(116,139)	(5,605,848)	21
22	Jan-36	35,810	2,614	38,554	622	76,672	118,462	0	(118,462)	(5,623,506)	22
23	Jan-37	36,526	2,667	39,325	634	78,206	120,831	0	(120,831)	(5,640,024)	23
24	Jan-38	37,256	2,720	40,111	647	79,770	123,248	0	(123,248)	(5,655,477)	24
25	Jan-39	38,001	2,774	40,913	660	81,365	125,713	0	(125,713)	(5,669,932)	25
26	Jan-40	38,761	2,830	41,732	673	0	45,235	0	(45,235)	(5,674,702)	26
27	Jan-41	39,537	2,886	42,566	687	0	46,139	0	(46,139)	(5,679,164)	27
28	Jan-42	40,327	2,944	43,418	700	0	47,062	0	(47,062)	(5,683,338)	28
29	Jan-43	(3,090)	(226)	(3,091)	(54)	0	(3,371)	0	3,371	(5,683,064)	29
30	Jan-44	1	0	0	0	0	0	0	(0)	(5,683,064)	30
31	Jan-45	1	0	0	0	0	0	0	(0)	(5,683,064)	31
32	Jan-46	1	0	0	0	0	0	0	(0)	(5,683,064)	32
33	Jan-47	1	0	0	0	0	0	0	(0)	(5,683,064)	33
34	Jan-48	1	0	0	0	0	0	0	(0)	(5,683,064)	34
35	Jan-49	1	0	0	0	0	0	0	(0)	(5,683,064)	35
36	Jan-50	1	0	0	0	0	0	0	(0)	(5,683,064)	36
37	Jan-51	1	0	0	0	0	0	0	(0)	(5,683,064)	37
38	Jan-52	1	0	0	0	0	0	0	(0)	(5,683,064)	38
39	Jan-53	1	0	0	0	0	0	0	(0)	(5,683,064)	39
40	Jan-54	1	0	0	0	0	0	0	(0)	(5,683,064)	40

Yukon Electrical AMR Project
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
REVENUES:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CAPITAL:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital	32,375	65,398	67,379	69,400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

O&M:	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
Manual Meter Reading Costs	0	470,016	479,416	489,005	498,785	508,760	518,936	529,314	539,901	550,699	561,713	572,947	584,406	596,094	608,016	620,176	632,580	645,231	658,136	671,299	684,725	698,419	712,387	726,635	741,168	755,991	771,111	786,533
Meter Test Costs	0	74,256	75,741	77,256	78,801	80,377	18,447	18,815	19,192	19,576	19,967	20,366	20,774	21,189	21,613	22,045	22,486	22,936	23,395	23,863	24,340	24,827	25,323	25,830	26,346	26,873	27,411	27,959
Customer Applications & Service Or	0	137,700	140,454	143,263	146,128	149,051	152,032	155,073	158,174	161,337	164,564	167,856	171,213	174,637	178,130	181,692	185,326	189,033	192,813	196,670	200,603	204,615	208,707	212,881	217,139	221,482	225,911	230,430
Data Cap Costs	0	21,216	21,640	22,073	22,515	22,965	23,424	23,893	24,371	24,858	25,355	25,862	26,379	26,907	27,445	27,994	28,554	29,125	29,708	30,302	30,908	31,526	32,156	32,800	33,455	34,125	34,807	35,503
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M	0	703,188	717,252	731,597	746,229	761,153	712,838	727,095	741,637	756,470	771,599	787,031	802,772	818,827	835,204	851,908	868,946	886,325	904,051	922,132	940,575	959,386	978,574	998,146	1,018,109	1,038,471	1,059,240	1,080,425

Yukon Electrical AMR Project
Conventional Meter Cost Impact

Year	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20	Jan-21	Jan-22	Jan-23	Jan-24	Jan-25	Jan-26	Jan-27	Jan-28	Jan-29	Jan-30	Jan-31	Jan-32	Jan-33	Jan-34	Jan-35	Jan-36	Jan-37	Jan-38	Jan-39	Jan-40	Jan-41
YEARLY DEPRECIATION:	**Rates**	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	8.090%	2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	8.090%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Depreciation		2,619	7,910	13,361	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	18,975	1,934	0	0	0	0	0	0	0	0	0	0	0	0

ACCUMULATED DEPRECIATION	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	2,619	10,529	23,890	42,865	61,840	80,815	99,791	118,766	137,741	156,716	175,692	194,667	213,642	232,617	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552	234,552
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PROPERTY IN SERVICE (beg yr	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27
1) meter replacement in 2008	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0
2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Project Ratebase	0	32,375	95,153	154,623	210,662	191,687	172,712	153,737	134,761	115,786	96,811	77,835	58,860	39,885	20,910	1,934	0	0	0	0	0	0	0	0	0	0	0	0

Yukon Electrical AMR Project
Conventional Meter Cost Impact

	Return	Ratio	B.T. Cost	A.T. Cost
Debt	5.800%	56%	0.0325	0.0325
Preferred	0.000%	0%	0.0000	0.0000
Common	9.210%	44%	0.0579	0.0405
Tax Rate	#####		9.037%	7.300%

CASH FLOWS SUMMARY:

	Year	Revenue Requirements						Revenue Allowance	Surplus (Deficit)	CPV at 9.037%	Used Year
		Ratebase	Return	Dep'n	Inc. Tax	O&M	Total				
0	Jan-14	0	0	0	0	0	0	0	0	0	0
1	Jan-15	32,375	2,364	2,619	562	703,188	708,733	0	(708,733)	(649,992)	1
2	Jan-16	95,153	6,947	7,910	1,653	717,252	733,761	0	(733,761)	(1,267,163)	2
3	Jan-17	154,623	11,288	13,361	2,685	731,597	758,931	0	(758,931)	(1,852,599)	3
4	Jan-18	210,662	15,379	18,975	3,659	746,229	784,242	0	(784,242)	(2,407,419)	4
5	Jan-19	191,687	13,994	18,975	3,329	761,153	797,452	0	(797,452)	(2,924,825)	5
6	Jan-20	172,712	12,609	18,975	3,000	712,838	747,422	0	(747,422)	(3,369,578)	6
7	Jan-21	153,737	11,223	18,975	2,670	727,095	759,964	0	(759,964)	(3,784,314)	7
8	Jan-22	134,761	9,838	18,975	2,340	741,637	772,791	0	(772,791)	(4,171,096)	8
9	Jan-23	115,786	8,453	18,975	2,011	756,470	785,909	0	(785,909)	(4,531,842)	9
10	Jan-24	96,811	7,068	18,975	1,681	771,599	799,323	0	(799,323)	(4,868,337)	10
11	Jan-25	77,835	5,682	18,975	1,352	787,031	813,040	0	(813,040)	(5,182,238)	11
12	Jan-26	58,860	4,297	18,975	1,022	802,772	827,066	0	(827,066)	(5,475,089)	12
13	Jan-27	39,885	2,912	18,975	693	818,827	841,407	0	(841,407)	(5,748,325)	13
14	Jan-28	20,910	1,526	18,975	363	835,204	856,069	0	(856,069)	(6,003,282)	14
15	Jan-29	1,934	141	1,934	34	851,908	854,017	0	(854,017)	(6,236,547)	15
16	Jan-30	0	0	0	0	868,946	868,946	0	(868,946)	(6,454,218)	16
17	Jan-31	0	0	0	0	886,325	886,325	0	(886,325)	(6,657,841)	17
18	Jan-32	0	0	0	0	904,051	904,051	0	(904,051)	(6,848,323)	18
19	Jan-33	0	0	0	0	922,132	922,132	0	(922,132)	(7,026,511)	19
20	Jan-34	0	0	0	0	940,575	940,575	0	(940,575)	(7,193,199)	20
21	Jan-35	0	0	0	0	959,386	959,386	0	(959,386)	(7,349,129)	21
22	Jan-36	0	0	0	0	978,574	978,574	0	(978,574)	(7,494,995)	22
23	Jan-37	0	0	0	0	998,146	998,146	0	(998,146)	(7,631,448)	23
24	Jan-38	0	0	0	0	1,018,109	1,018,109	0	(1,018,109)	(7,759,094)	24
25	Jan-39	0	0	0	0	1,038,471	1,038,471	0	(1,038,471)	(7,878,501)	25
26	Jan-40	0	0	0	0	1,059,240	1,059,240	0	(1,059,240)	(7,990,203)	26
27	Jan-41	0	0	0	0	1,080,425	1,080,425	0	(1,080,425)	(8,094,695)	27
28	Jan-42	0	0	0	0	1,102,034	1,102,034	0	(1,102,034)	(8,192,443)	28
29	Jan-43	0	0	0	0	0	0	0	(0)	(8,192,443)	29
30	Jan-44	0	0	0	0	0	0	0	(0)	(8,192,443)	30
31	Jan-45	0	0	0	0	0	0	0	(0)	(8,192,443)	31
32	Jan-46	0	0	0	0	0	0	0	(0)	(8,192,443)	32
33	Jan-47	0	0	0	0	0	0	0	(0)	(8,192,443)	33
34	Jan-48	0	0	0	0	0	0	0	(0)	(8,192,443)	34
35	Jan-49	0	0	0	0	0	0	0	(0)	(8,192,443)	35
36	Jan-50	0	0	0	0	0	0	0	(0)	(8,192,443)	36
37	Jan-51	0	0	0	0	0	0	0	(0)	(8,192,443)	37
38	Jan-52	0	0	0	0	0	0	0	(0)	(8,192,443)	38
39	Jan-53	0	0	0	0	0	0	0	(0)	(8,192,443)	39
40	Jan-54	0	0	0	0	0	0	0	(0)	(8,192,443)	40

YUB-YECL-49

Reference: Old Crow Unit #3 Replacement, YECL Application, Business Case #15, page 2

*Purchase and install a new **250kW** unit to replace the existing undersized 170kW unit (CUL 384). Load growth and load duration of Old Crow community have steadily diminished the utilization of the existing unit due to its rated capacity. The new 250kW unit will be installed in the new building in Old Crow (see Business Case #8), as it will not physically fit in the existing building, so the purchase of new switchgear and engine controls components is also required. [emphasis added]*

Request:

(a) Please provide the ages and operating hours of the units in the Old Crow generating plant? Will the units soon be at the end of life?

(b) Please indicate what future plans YECL has in respect of unit CUL 384.

Response:

(a) Unit 2 could be eligible for replacement in 2017 or 2018 if annual operating hours continue on the past 2 year average.

Unit #	Engine Year of Manufacture	Engine Hours (December 2012)	Forecast Retirement Year
1	1998	20,184	2022+
2	1991	57,141	2017
3	1992	28,879	2015

(b) CUL 384 will be removed from service in Old Crow and sold.

YUB-YECL-50

Reference: Hillcrest Subdivision Conversion, YECL Application, Business Case #18, Page 2

The project is to reduce the load on 4L306 by converting a subdivision to 25kV electrical infrastructure and transferring to 5L630. The existing infrastructure is also at end of life condition with poor condition of poles and aged electrical hardware that is degrading.

The Hillcrest subdivision load is to be converted to 25kV and transferred to 5L630.

Request:

Once the conversion is completed and throughout the conversion, what are the contingency plans if there is a fault on either 4L306 or 5L630?

Response:

The will be no change in contingency for 5L630. As Hillcrest is converted and transferred from 4L306 to 5L630, the additional distribution in Hillcrest that is added to 5L630 will be newly constructed infrastructure which inherently has fewer issues.

It is very similar circumstance for 4L306. Currently, Hillcrest is a radial feed at the end of this line. Accordingly, any outage on 4L306 and 5L630 would affect the Hillcrest area as it is at the end of the respective distribution lines. Yukon Electrical emergency crews would have to locate and repair the problem.

YUB-YECL-51

Reference: Crestview to mayo Road Corner Double Circuit, YECL Application, Business Case #21, page 2

Build a new distribution line in double circuit configuration from Crestview area to the Mayo road intersection. The new 34.5 kV top distribution line will be built with 266 ACSR conductors. The bottom circuit, 5L628, will be replacing the existing distribution line. Permitting, easements, brushing and construction will be completed to standard.

Request:

(a) Please provide an itemized list of the costs that make up the forecast $0.6 million total for this project.

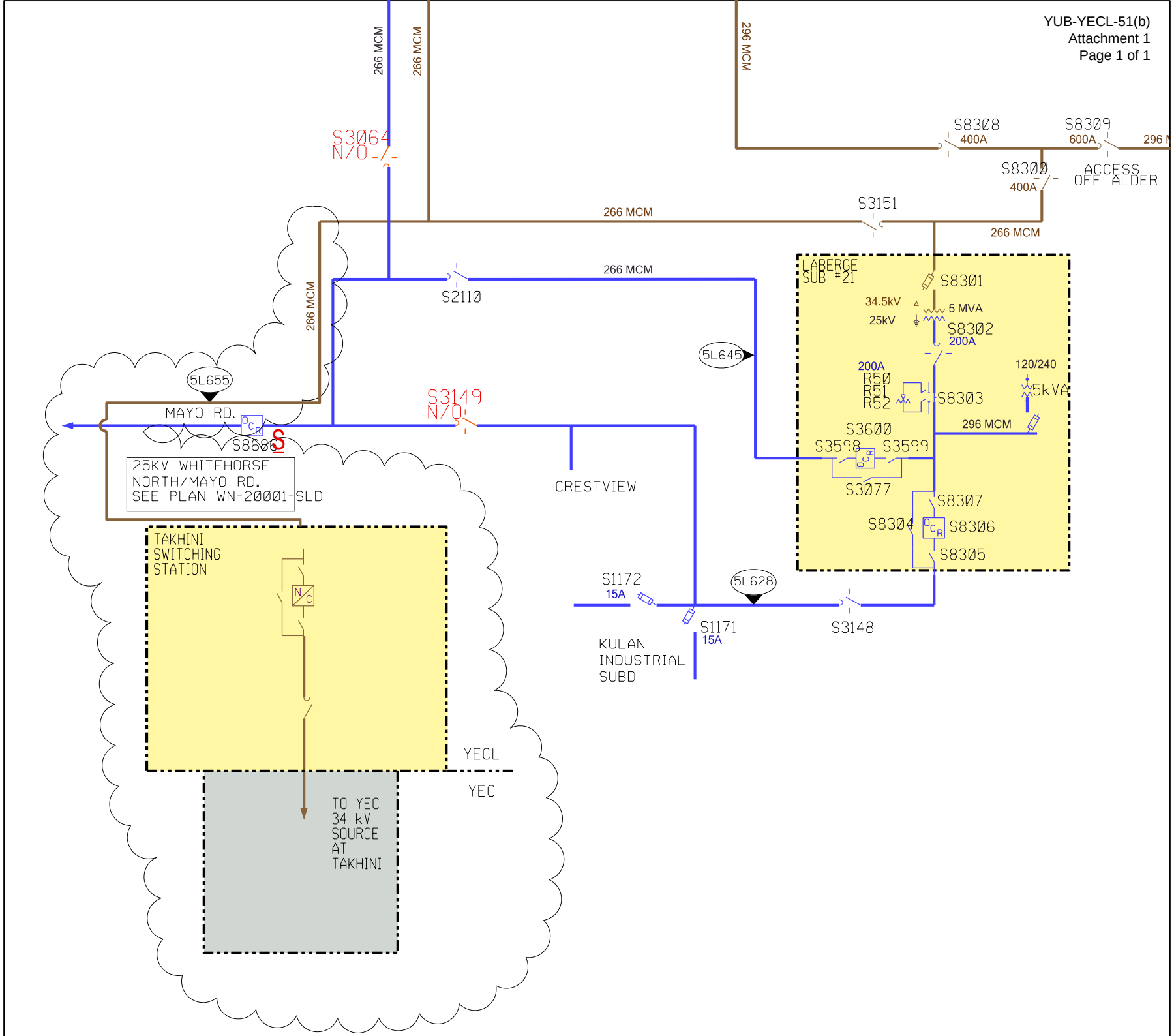
(b) Please provide a single-line diagram showing the proposed 34.5kv line, 5l628 and the new YEC substation for which business cases 21 and 23 apply.

Response:

(a) The costs in 2012 for this project were made up of:

Materials	$218,000
Labour Charges	20,000
Contract Services	389,000
Other	1,000
Total Costs	$628,000

(b) Please refer to YUB-YECL-51(b) Attachment 1.



WH-20001.dgn NTS

YUB-YECL-52

Reference: Whitehorse 5L628 and new 35kV Build, YELCL Application, Business Case #23, page 2

The project is to build a double circuit distribution line on the North Klondike Highway to the Yukon Energy Takhini Switching Station.

The new top circuit will be built to 34.5kV standards with sufficient capacity to safely accommodate the design of the supply source.

The bottom circuit will be a replacement of 5L628 in this area. The existing line in the area serves all customers on the North Klondike Highway (approximately 750). Most poles in the area are unable to accommodate the addition of another circuit. Where possible, existing infrastructure will be utilized to complete the project.

Request:

Please provide an itemized list of the costs that make up the forecast $1.9 million total for this project.

Response:

Forecast costs for this project:

Materials	$1,171,800
Contract Services	661,500
Labour	56,700
Total forecast costs	$1,890,000

YUB-YECL-53

Reference: Fish Lake Water Licence Renewal, YECL Application, Business Case #28

Request:

(a) Please provide a comprehensive list of the activities that make up the expenses incurred in 2011, 2012 and 2013, respectively $491,000, $688,000 and $650,000.

(b) At what stage of renewing the water licence is YECL?

(c) At this point, can YECL confirm that no further modifications to the Fish Lake hydro facility that will arise (a) as a result of acquiring the licence, or (b) out of the licensing requirements?

(d) In addition to part (c), does YECL see any increases related to operating and maintenance activities that may arise out of the new Fish Lake licensing requirements? Please explain.

(e) Have all studies been undertaken that are required with respect to renewing YECL's Fish Lake long-term licence? Please explain.

(f) In addition to the long-term licensing requirements, is it YECL's intent to perform any studies, notwithstanding that said studies may not be related to Fish Lake licensing requirements? Please explain.

Response:

(a) Please refer to YUB-YECL-53(a) Attachment 1.

(b) On May 29, 2013, the Yukon Water Board issued to Yukon Electrical a 25-year Water Use Licence (HY12-065) to operate the Fish Lake hydro system from May 31, 2013 until May 30, 2038. Thus, the licence renewal has been completed.

(c) Yukon Electrical can confirm that all modifications of the Fish Lake hydro system, as directed by Water Use Licence HY12-065, are included in the capital forecast included in the Application and no further additions or modifications will be needed during the test years as a result of the Water Use Licence.

(d) Yukon Electrical has forecast and applied for all increased requirements related to operating and maintaining the Fish Lake Hydro system in its Application.

Yukon Electrical recognizes that these increased management efforts add to the cost of managing the system. For this reason, significant effort was made during the relicensing process to seek as efficient management requirements as possible.

At the public hearing to consider Yukon Electrical's long term licence application, Yukon Electrical specifically raised the issue of ratepayers' interests and the fact that the Yukon Water Board needs to consider those interests in determining the conditions of the requested licence. The following text from Yukon Electrical's opening statement demonstrates that efforts were made to ensure that regulation and requirements were efficient:

> Also it is important for the Board to understand that while we sit here as Yukon Electrical seeking this long term licence, we also represent the interests of Yukon ratepayers who are not otherwise represented before you. As a regulated industry, we have an obligation to our ratepayers for prudent fiscal management of this resource to best meet ratepayers' needs. In that vein we respectfully ask that the Board in its deliberations consider the impact of potential licence conditions on ratepayers. Regulation through a water use licence is of course an appropriate requirement but excessive regulation that does not fundamentally improve or impact operations and its effects will have a direct impact on ratepayers and this should be considered.
>
> It is important to understand that this is a small hydro project, with a limited revenue stream to offset investments and operating expenses which include future studies and monitoring activities. To that end, the term of this licence is important as it allows the substantial investments made today and those we have proposed, to be spread out sustainably for ratepayers. It is also important that the flexibility incorporated into the two decision documents issued for this project be extended into the conditions of water use licence. This is so that the inherent flexibility, included in many of the decision document conditions, to adapt monitoring and studies in consultation with Regulators and KDFN can be realized if they are found to be supported by the results of monitoring in early years of

the new licence. This would ensure that unnecessary activities and arising expenses are not forced upon ratepayers.

We respectfully point out that this legacy project is unlike most undertakings considered by the Board in that there is strong operational evidence to support how the project will work since it has been working for over 60 years. Irrespective of modelling and studies, the past operation speaks for itself and should provide the Board comfort that it can continue to operate in an overall beneficial manner.

(e) All studies required for the renewal of a long term Water Use Licence have been completed. There are on-going requirements for studies as part of the new Water Use Licence. The costs for these studies have been forecast in account 62600 and included in Yukon Electrical's Application. Please refer to YUB-YECL-8 for further details.

(f) It is not Yukon Electrical's intent to perform any non essential studies.

The Yukon Electrical Company Limited
Breakdown of Expenses Incurred Related to Fish Lake Water Licence Renewal

Expenses Incurred:	2011	2012	2013 *
Labour	54,924	62,554	25,382
Contract Services	435,111	507,872	747,737
Other	758	117,975	45,226
Total	**490,793**	**688,401**	**818,345**

* Actual expenses incurred for 2013, which are $168,345 higher than the $650,000 forecast in the Application.

Breakdown of Contract Services:

2011	AMOUNT	SERVICES PROVIDED
AECOM Canada Ltd.	160,473	Fisheries & Aquatic Study & Professional Services Support
Bennett Jones LLP	90,233	Legal Services in Preparation and Representation during Yukon Water Board Hearing for Water Licence
Northland Earth & Water Consulting Inc	58,748	Dam Safety Report & Professional Services Support
EDI Environmental Dynamics Inc	56,869	Bird Study - Louise Lake & Coal Lake, Fish Lake & Louise Lake Erosion Study, Professional Services Support
Underhill Geomatics Ltd	52,470	Innundation Study & Diversion Water Routing
Can Nic A Nick Environmental	5,845	Water Monitoring
Other Consulting Fees	10,473	
Total Contract Services - 2011	**435,111**	

2012	AMOUNT	SERVICES PROVIDED
AECOM Canada Ltd.	260,628	Preparation of Water Licence Application, YESAB application & Professional Services Support
EDI Environmental Dynamics Inc	108,745	Jackson Creek Watershed Study & Professional Services Support
Northland Earth & Water Consulting Inc	100,738	Dam Safety Report, Hydraulics & Professional Services Support
Bennett Jones LLP	20,600	Legal Services in Preparation and Representation during Yukon Water Board Hearing for Water Licence
Underhill Geomatics Ltd.	10,078	Various Surveys
Other Consulting Fees	7,084	
Total Contract Services - 2012	**507,872**	

2013	AMOUNT	SERVICES PROVIDED
Bennett Jones LLP	373,308	Legal Services in Preparation and Representation during Yukon Water Board Hearing for Water Licence
Various	215,149	First Nations Land Tenure, Access and Monitoring
AECOM Canada Ltd.	42,200	Preparation of Water Licence Application
EDI Environmental Dynamics Inc.	39,219	Expert Witness at Hearing on Ecological Studies
Northland Earth & Water Consulting Inc.	34,634	Expert Witness at Hearing on Hydraulic and Waterflow Analysis
Morrison Hershfield Ltd.	27,600	Expert Witness at Hearing on Water Licence Application
D R Toews Environmental Consulting	14,438	Expert Witness at Hearing on Fish Studies
Other Consulting Fees	1,189	
Total Contract Services - 2013	**747,737**	

YUB-YECL-54

Reference: Downtown Office Building Envelope Upgrades, YECL Application, Business Case #29, page 2 and 3

This project will replace the exterior building envelope of Yukon Electrical's downtown office. The exterior upgrades are required to improve the energy efficiency of the building and create a more comfortable environment for staff and customers, as well as preventing further water damage and potential mold growth in the future.

A Building Evaluation Report was prepared in Q4 2011 that recommends that upgrades be carried out to the exterior of the building to improve and update the overall integrity of the building. The upgrades will also improve the comfort level of the occupants ***and it is projected that these improvements will result in an annual reduction in energy costs of 20%.*** *[emphasis added]*

….

….

- *The changes to the exterior construction and increase in insulation will also result in cost savings and environmental benefits due to a reduction in both electricity use and furnace fuel consumption.*

Request:

With respect to the projected 20% reduction in energy costs, please provide a cost/benefit analysis that illustrates the project payback based on forecast energy savings.

Response:

Yukon Electrical is not able to demonstrate an economic payback for the project related to energy cost savings. Based on heating oil operating costs for the last three years, the savings are $1,500/year. However, this is only a minor benefit to the project and is not the primary reason why the project must be completed. The building envelope has failed allowing moisture ingress, which presents a health concern for employees and customers, as well as a risk to building integrity, and this is the primary reason why Yukon Electrical plans to update the building envelope. The photographs of the facade included in Business Case #29 show the deteriorated condition of the building exterior.

YUB-YECL-55

Reference:

Yukon Electrical seeks the following approvals from the Board:

…

(2) Approval of the continued use of the deferral accounts listed in detail later in this section during the test period;

…

A new industrial customer, Whitehorse Copper Tailings (WHCT), is forecast to start operations in the fall of 2013. While the customer has acknowledged uncertainty in the exact timing of its start-up as well as its ultimate load, the latest available information results in a 2013 forecast of 1,025 MWh and 4,620 MWh for each of 2014 and 2015.

… As WHCT is a single industrial customer that could contribute materially higher or lower than 1.4% of Yukon Electrical's total forecast sales and the exact timing of its start-up and eventual load are not within the control of Yukon Electrical, Yukon Electrical is requesting a deferral account relating to WHCT sales uncertainty.

Request:

Does YECL envision drafting a purchase power agreement with WHCT, similar to what the Yukon Energy Corporation (YEC) has in place with Minto and Alexco mines, in order to safeguard the utility and its customers? Please provide a detailed explanation.

Response:

Yukon Electrical proposes to apply to the Yukon Utilities Board for approval of a power purchase agreement once the details of the customer requirements are available.

Yukon Electrical proposes to utilize Rate Schedule 39 as being applicable to all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

The components of the present rate include a demand charge of $15.42/kV.A and an energy charge of 7.81¢/kW.h for all energy used. A fixed charge is applied for monthly Capital Cost Contributions for connection to the Yukon Interconnected System.

YUB-YECL-56

Reference: Yukon economic activity, YECL Application, Section 2, pages 2-3

The latest economic projection from the Yukon Government, however, suggests a sharp slowdown in the pace of economic activity in 2012 and 2013. The Yukon Territory real Gross Domestic Product is estimated to have grown in the range of 2%-3% in 2012 and is expected to grow only 2% in 2013, down sharply from the 2011 growth rate of 6.5%. The Territory's unemployment rate rose to 6.9% in 2012, from 5.4% in 2011, and is projected to rise further, to 7.3%, in 2013. The Yukon Government also expects a slower population growth in 2013, dropping from 2.1% in 2012 to 1.3%. The value of building permits is estimated to have dropped 43% in 2012, compared to 2011. In its latest Northern Housing Report, Canada Mortgage and Housing Corporation forecast a 25% decrease in Whitehorse housing starts in 2012 as compared to 2011.

The projections were based on forecasts from Yukon Economic Review 2012, Yukon Economic Development (February 5, 2013), and Northern Housing Report, Canada Mortgage and Housing Corporation, 2012.

Request:

Please provide the Yukon Government's latest economic projection for 2012 and for each year of the test period.

Response:

Please refer to YUB-YECL-56 Attachment 1. An economic projection for 2014 and 2015 is not available.

Yukon Economic Review 2012

Whitehorse, Yukon
February 5, 2013

NOTE: The Yukon Economic Outlook 2012 was released on May 30, 2012. The review for 2012 contains information as recent as February 5, 2013. Updates to the May forecast document are highlighted in the shaded text boxes included at the end of each section.

Yukon
Economic Development

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Highlights for 2011

Current as of May 30, 2012

- Preliminary estimates by Statistics Canada indicate that Yukon's real GDP grew 5.6% to $1.776 billion, from $1.681 billion in 2010. Gains in real GDP in 2011 marked the eighth consecutive year of growth.
- Yukon's average annual population increased by 1.6% in 2011 to 35,391. Increasing population in 2011 marked the eighth consecutive year of growth.
- Yukon's average unemployment rate of 5.4% for 2011 was down from 6.9% in 2010 and well below the national average of 7.5%.
- Mineral exploration expenditures in 2011 are estimated at nearly $307 million, topping the previous record high of $157 million in 2010.
- The value of Yukon mineral production for 2011 is estimated at $402 million, up from $299 million in 2010.
- Over 114,000 quartz claims were staked in Yukon in 2011, 38% higher than the previous record high of 83,161 recorded in 2010.
- In 2011, the Department of Tourism and Culture reported 309,863 visitors (border crossings), down slightly from 311,542 in 2010.
- The value of Yukon building permits in 2011 was a record $176.8 million, 34% higher than the $131.8 million reported for 2010.
- The value of retail sales in Yukon totaled a record $662 million in 2011, up 10.6% from $599 million in 2010.

Forecast for 2012

- Yukon's real GDP is expected to increase by 3% in 2012, with growth related primarily to increased mineral production.
- With labour force growth expected to outpace employment growth in 2012, the unemployment rate is expected to increase to 6.5%-7.0%.
- Yukon's population is forecast to average 36,000 in 2012, marking the ninth straight year of population growth.
- The value of mineral production is expected to total almost $600 million, up from the 2011 estimate of $402 million. Growth in 2012 is expected to stem primarily from higher production from the Wolverine mine, which declared commercial production in March 2012.
- Border crossings are expected to total about 313,000 in 2012, up slightly from approximately 310,000 in 2011.
- The value of building permits in 2012 is expected to be $150 million, down from the record $177 million in 2011, but well above the long-term average.
- Retail sales are expected to continue to benefit from a strong economy and total approximately $690 million in 2012, representing a 4% increase from 2011.

2012 Highlights – February 2013 Update:

- Current expectations are that real GDP growth in 2012 will be in the range of two to three per cent.
- The Yukon population in 2012 is now expected to average slightly less than the May forecast of 36,000.
- Yukon's labour market remained strong in 2012 with employment averaging 18,900 and the labour force averaging 20,400, a new record.
- The rate of growth in Yukon's labour force outpaced the growth of employment in 2012 which saw Yukon's unemployment rate increase to 6.9 per cent, up from 5.4 per cent in 2011.
- Annual average inflation for 2012 was 2.3 per cent, slightly below the May forecast of 2.5 per cent, and below the 3.0 per cent average of 2011.
- While exploration spending in 2012 will fall below the estimated record of over $300 million for 2011, interest in exploration in Yukon remains strong. Current expectations have exploration expenditures in 2012 at about $150 million, the third highest level on record.
- Benefitting primarily from higher production from the Wolverine mine, the value of Yukon's mineral production is expected to have grown for the seventh consecutive year in 2012, and total about $450 million, up from an estimated $402 million in 2011.
- Based on year-to-date border crossing data for 2012 annual tourist visitation is expected to have grown to about 321,000, 3.6 per cent higher than the 309,863 recorded in 2011 and well above the May 2012 forecast of 313,000.
- Building permit value for 2012 is estimated at $100.4 million, a decline of 43 per cent from 2011.
- Given the growth in retail sales posted in the first 11 months of 2012, the 2012 total will fall below the May forecast, but total over $675 million, up by over 2 per cent from $662.2 million in 2011.

Global, U.S. and Canadian Economic Outlook – 2011/2012

It was a year of significant uncertainty for the global economy in 2011. Fears of a second global economic downturn since 2008 persisted and were primarily related to worries about the difficult fiscal situations of some countries in the eurozone and the worry that potential defaults of some countries could have substantial impacts on the European banking system. This has had ramifications for global financial markets including decreased liquidity, the impacts of which have even been felt in Yukon. The performance of the U.S. economy also did little to ease global economic concerns in 2011, which has seen a recovery from the previous economic downturn that has been slower than many analysts expected. In addition, a number of Middle East countries saw internal conflicts, and in some cases changes in leadership that contributed to heightened geopolitical tension and concerns about interruptions in global economic oil supply. All of these events helped keep the price of oil high throughout 2011, likely dampening economic growth in some countries.

The most recent World Economic Outlook, published by the International Monetary Fund (IMF) in April 2012, estimates global economic growth of 3.9% for 2011.[1] Growth in 2011

[1] http://www.imf.org/external/pubs/ft/weo/2012/01/index.htm

was noted as lower than in 2010, where growth was estimated at 5.3%. As has been the case in recent years, growth rates in 'emerging and developing economies' in 2011 are estimated to have exceeded those of 'advanced economies' with overall growth for emerging countries estimated at 6.2%, almost four times the 1.6% growth noted for advanced economies. Leading the way for the emerging economies are China and India, which are estimated to have grown 9.2% and 7.2% respectively in 2011.

The World Economic Outlook (April 2012) includes global economic forecasts of 3.5% for 2012 and 4.1% for 2013, with growth in emerging and developing economies expected to be far more robust than growth in developed economies. Advanced economies are expected to post growth of 1.4% and 2.0% in 2012 and 2013 respectively. Emerging and developing countries are expected to post much higher growth with the IMF forecasting growth of 5.7% for 2012 and 6.0% for 2013. China and India, while expected to experience lower GDP growth than recorded in recent years, is expected to continue to fuel economic growth of emerging and developing countries in both 2012 and 2013. Strong domestic demand in these countries along with continuation of strong demand for oil resources from some of the other emerging and developing countries is expected to contribute to growth in the near-term.

The IMF (April 2012) is estimating economic growth of 1.7% for the United States for 2011, lower than the 3.0% growth estimate for 2010. Growth prospects for the U.S. are looking marginally better going forward with the IMF estimating growth of 2.1% for 2012 and 2.4% for 2013. Improving labour markets, higher consumer and business confidence, fiscal consolidation and generally improving household debt levels are all helping to improve the outlook for the U.S. economy. The conclusion of presidential elections in November should also help provide political certainty for the U.S.

Following estimated growth of 2.5% for 2011 for Canada, the IMF is projecting slightly weaker growth of 2.1% and 2.2% for 2012 and 2013 respectively. Canada's recent economic performance has been stable, with Canada generally outperforming most advanced economies. Canada's stable banking system, abundance of valued natural resources, as well as targeted monetary and fiscal stimulus have all contributed to Canada's continued economic growth. Going forward, the demand for Canadian oil and mineral resources is expected to remain strong, which will continue to contribute to Canada's economic growth prospects.

While global growth prospects have improved since late 2011, downside risks to growth remain. Even with the actions taken to address concerns of fiscal sustainability in some European countries the possibility of continued economic and fiscal troubles in Europe remains. Heightened concerns for defaults for some European countries could see investors move to pull resources out of the euro area which could have serious impacts on European and global growth prospects. Escalated unrest in a number of oil-producing countries could also place pressure on global oil prices, as fear of interruptions of global oil supply increases the risk premium on oil. A prolonged period of high oil prices would likely dampen global economic growth prospects, possibly stalling the recoveries of some advanced economies and placing downward pressure on emerging economies. Global growth prospects could also be impacted negatively if oil prices contribute to losses in consumer and business confidence and possible volatility on financial markets.

From a Canadian perspective, a number of areas could impact near-term growth. The Canadian dollar has had a prolonged period of strength versus the U.S. dollar, but further appreciation could have negative impacts on Canadian exports to the U.S. as a high dollar increases the relative costs of Canadian goods to American customers. Canadian exports could also be negatively impacted by a slowdown in the U.S. economic recovery, or lower demand from some European countries and parts of Asia.

In its most recent interest rate announcement on April 17, 2012, the Bank of Canada signaled that an increase in interest rates may be coming. The Bank, citing improving global economic prospects, noted that some modest withdrawal of monetary stimulus could become appropriate. With warnings from the Bank that many Canadians are carrying higher debt levels, an interest rate increase could have negative impacts on Canadian economic activity, as households face higher debt servicing costs. Ultimately the Bank's decision to raise interest rates will be dependent on a number of factors.

Further increases in oil prices may also impact Canadian households as increasing prices would reduce households' discretionary income, likely resulting in lower spending in certain areas of the economy. Higher oil prices could also impact the cost of manufacturing of a variety of goods, and also increase the costs of certain services, which could also have negative consequences for Canadian growth going forward.

Outlook for Global, U.S. and Canadian Economies

- The IMF's World Economic Outlook (April 2012) includes the following:
  - The global economy to grow by 3.5% in 2012 and 4.1% in 2013.
  - The U.S. economy to grow by 2.1% in 2012 and 2.4% in 2013.
  - The Canadian economy to grow by 2.1% in 2012 and 2.2% in 2013.

Global, U.S. and Canadian Outlook – February 2013 Update: While not insulated from the prevailing weakness in the global economy, strong fundamentals, including a stable banking system and abundant natural resources, has positioned Canada well to deal with the current economic headwinds.

The International Monetary Fund (IMF) reported in its January 2013 update to the *World Economic Outlook* that global economic growth is now expected to be 3.2 per cent for 2012 and 3.5 per cent for 2013. This follows estimated global economic growth of 3.9 per cent in 2011 and represents downward revisions from its October 2012 projections of 3.3 per cent growth for 2012 and 3.6 per cent growth for 2013.

The IMF's January update noted that policy actions have lowered risks in the euro area and the United States, but that the economic recovery in the euro area has been delayed. The IMF has indicated that global growth could exceed projections if "crisis risks do not materialize and financial conditions continue to improve" but that downside risks to the global economy, including setbacks in the euro area and excessive U.S. fiscal consolidation in the short term, remain significant.

For emerging and developing economies, the driver of global economic growth in recent years, growth is expected to be healthy, but below the growth levels recorded in 2010 and 2011. The IMF estimates growth of 5.1 per cent for 2012 and is projecting growth of 5.5 per cent growth for 2013. For China, the primary engine of growth in emerging markets in recent years, the IMF is estimating growth of 7.8 per cent in 2012 and forecasting growth of 8.2 per cent in 2013.

The IMF has revised down its near-term outlook for the euro area, with the euro area now expected to contract 0.2 per cent in 2013, down from the October 2012 forecast of 0.1 per cent growth. A contraction in 2013 would mark the second consecutive year of negative growth in the euro zone, following a 0.4 per cent contraction in 2012. The IMF noted that the euro area continues to pose a significant downside risk to global growth prospects.

The IMF's January 2013 projections for the U.S. have GDP growth of 2.3 per cent and 2.0 per cent for 2012 and 2013 respectively. These projections are broadly unchanged from the October outlook. Recent positive news on the U.S. employment front and signs of improvement in the U.S. housing market indicate that the U.S. economy is improving. A last minute deal to avoid automatic tax increases and mandatory spending cuts on January 1, 2013 was also good news for the U.S., and ultimately the global, economy. Going forward, performance of the U.S. economy will depend very much on the ability of policymakers to develop a plan to address the country's deficit issues and to deal with the issue of raising the federal debt ceiling during the first quarter of 2013. High consumer debt and uncertainty in the financial markets also remain a concern going forward.

The IMF's January update notes growth for Canada at 2.0 per cent and 1.8 per cent for 2012 and 2013, respectively. The current forecasts for Canada exceed the IMF's 2012 and 2013 forecasts for all Advanced Economies.

The Bank of Canada's January *Monetary Policy Report* noted growth of 1.9 per cent for 2012 and a forecast of 2.0 per cent for 2013. The Bank lowered growth estimates for both 2012 and 2013 noting that the slowdown in the second half of 2012 was more pronounced than anticipated. The Bank now expects the pace of economic growth in Canada to pick up through 2013 with the Canadian economy now expected to return to full capacity in the second half of 2014.

Yukon Outlook – Economic Sectors
Mining

Yukon's mining sector is in the midst of a strong period of growth with mining activity currently taking place in all areas of the mining life cycle. Current expectations for 2012 have Yukon's mining sector building on the recent strong performance, with the sector well-positioned to be a significant contributor to Yukon's economy for the foreseeable future.

There were over 100 companies doing exploration work in Yukon in 2011, with over 50 of these companies estimated to have spent in excess of $1 million each on exploration-related work. Natural Resources Canada's (NRCAN) Survey of Mineral Exploration, Deposit Appraisal & Mine Complex Development Expenditures indicates that exploration expenditures in 2011 totaled nearly $307 million, which is the highest value on record, and well above the $157 million estimated for 2010. Early indications are that 2012 mineral exploration spending will fall short of the record level reported for 2011, as concerns related to the global economy are making it difficult for mining companies to raise capital. This results in companies budgeting less for exploration-related activities. Current expectations are that mineral exploration expenditures could fall within $160-$200 million, which would be the second highest total on record, and would be well above the historic average.

Interest in Yukon's mineral potential is also being reflected in staking activity in recent years. In 2011, a record 114,587 new claims were staked, 38% higher than the high of 83,161 recorded in the previous year. Expectations for 2012 are that staking activity in the territory will fall well below the record level of 2011, but remain above the historic average.

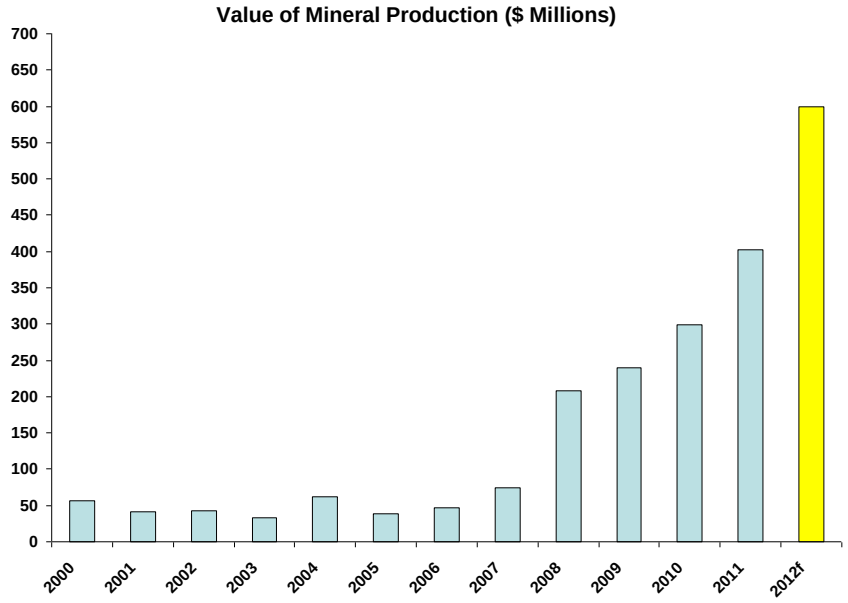
Driving much of the recent exploration activity has been strong growth in gold prices, which have doubled since 2007, and have shown tremendous gains in the last two years. It is estimated that exploration activities related to gold accounted for almost 70% of all mineral expenditures in 2011. With the expectation that gold prices will remain high for the foreseeable future, gold exploration will likely account for a significant portion of Yukon exploration activities going forward.

Following a period of strong development activity that has seen three mines developed and brought into production since 2005, development expenditures in 2012 are expected to fall below recent levels. Due primarily to development work associated with the Wolverine and Bellekeno mines, development expenditures in both 2010 and 2011 were estimated at about $150 million. With the vast majority of the development work associated with these projects now complete, development costs in 2012 will likely decline to less than half of the total seen in the last two years. Contributing to development expenditures in 2012 will be Capstone Mining Corp., which has budgeted over $32 million for capital expenditures on work related to the Minto mine, and Yukon Zinc Corp., which has budgeted $10-$15 million for continued work on the Wolverine project. Further expenditures could be seen on the Bellekeno project and the Victoria Gold project.

With Yukon Zinc Corp. filing Notice of Commencement of Production in March 2012, Yukon now has three commercially producing mines. Production from these mines, along with the production value of placer gold, is forecast to generate about $600 million in

mineral production value in 2012, far exceeding NRCAN's estimates of $402 million for 2011 and $299 million for 2010.[2] The additional mineral production in 2012 will be a significant contributor to Yukon's real GDP growth in 2012.

Placer gold production has been generally stable in recent years. Production in 2011 totaled 46,485 ounces; 9.4% lower than the 51,302 ounces produced in 2010. Current expectations for 2012 are for placer gold production to approach the 2010 level and total about 50,000 ounces.



Source: Natural Resources Canada; Department of Economic Development

Prices for minerals of interest to Yukon have generally been strong in recent years with annual gains in both 2010 and 2011 for gold, silver, copper, zinc and lead. The recent performance of gold and silver price in particular has been very strong. Gold prices in 2011 approached US$1,900 per ounce and averaged about US$1,570 per ounce for the year, 28% higher than the 2010 average of about US$1,225 per ounce. Silver prices in 2011 averaged over US$35 per ounce, up 74% from about US$20 per ounce in 2010.

While copper, zinc and lead prices have not surged like that of the prices for gold and silver, prices for all three of these metals have recorded recent gains.

- Copper prices averaged US$4.00 per pound in 2011, up 17% from US$3.42 per pound in 2010 and 71% from US$2.34 in 2009.
- Zinc prices averaged US$0.99 per pound in 2011, similar to the level recorded in 2010 and from US$0.75 per pound in 2009.
- Lead prices averaged US$1.09 per pound in 2011, up from US$0.97 per pound in 2010 and US$0.78 in 2009.

[2] NRCAN, 2011 Preliminary Estimate of Mineral Production http://mmsd.mms.nrcan.gc.ca/stat-stat/prod-prod/2011-eng.aspx

Continued economic uncertainty, especially in relation to the U.S. and some European countries, is expected to contribute to mixed performance for mineral prices in 2012. Gold and silver prices are expected to continue to perform well, with a number of forecasters expecting gains in price for both of these precious metals. Estimates for 2012 vary by forecaster. At the time of writing TD Economics was forecasting gold at US$1,766 per ounce and silver at US$35.02 per ounce, while BMO Capital Markets was forecasting gold at US$1,675 per ounce and silver at US$34.25 per ounce. Forecasters are less bullish on the prospects for copper, and zinc prices in 2012 with current expectations for prices to be steady, or slightly lower than the levels posted in 2011.

With three producing mines and a number of other projects advancing towards development decisions, the future of Yukon's mining sector looks promising. Currently there are six projects that have gone through permitting or in the process of obtaining the appropriate permits. There are also 10 projects that are doing advanced exploration or are completing feasibility-related work. A number of the project proponents have noted development timelines that could see development and production within five years.

While it is certainly the case that mining activities in Yukon are impacted by what is happening in the global economy and in the global mining sector, Yukon seems to be well-positioned to capitalize on the strong interest in its mineral resources. The expectation going forward is that development of Yukon's mineral sector will continue, with mining-related activity continuing to be an important contributor to Yukon's economy for the foreseeable future.

Outlook for Mining

- Mineral exploration spending in 2012 to fall in the $160-$200 million. This would be the second highest on record.
- With the vast majority of the development work associated with newly producing projects now complete, development costs in 2012 will likely decline to about half of the total seen in the last two years.
- The value of mineral production could total about $600 million in 2012, up from $402 million in 2011. Growth in 2012 is expected to stem primarily from a significant increase in production from the Wolverine mine which declared commercial production in March 2012.

Mining – February 2013 Update: While exploration spending in 2012 will fall below the estimated record of over $300 million for 2011, interest in exploration in Yukon remains strong. Current expectations have exploration expenditures in 2012 at about $150 million, the third highest level on record. In 2012, over 80 exploration projects were active in the territory, with over 30 of these spending at least $1 million.

Exploration for gold continues to account for the majority of recent exploration spending in Yukon. In 2012, exploration for gold accounted for 69 per cent of all exploration expenditures, well ahead of zinc-lead (11 per cent), silver (9 per cent), nickel-platinum (7 per cent) and copper (4 per cent). The price of gold, unlike those of the other commodities noted, recorded gains in 2012 with the price up 6.1 per cent, to almost US$1,670 per ounce.

In terms of staking activity, 2012 was more in line with staking activity seen prior to 2010. Claims staked in 2012 totaled fewer than 12,000, well below the over 114,000 claims staked in 2011.

Current estimates have development expenditures for 2012 near $100 million, down from an estimated $150 million in 2011, but above the May forecast for 2012 of $70 million.

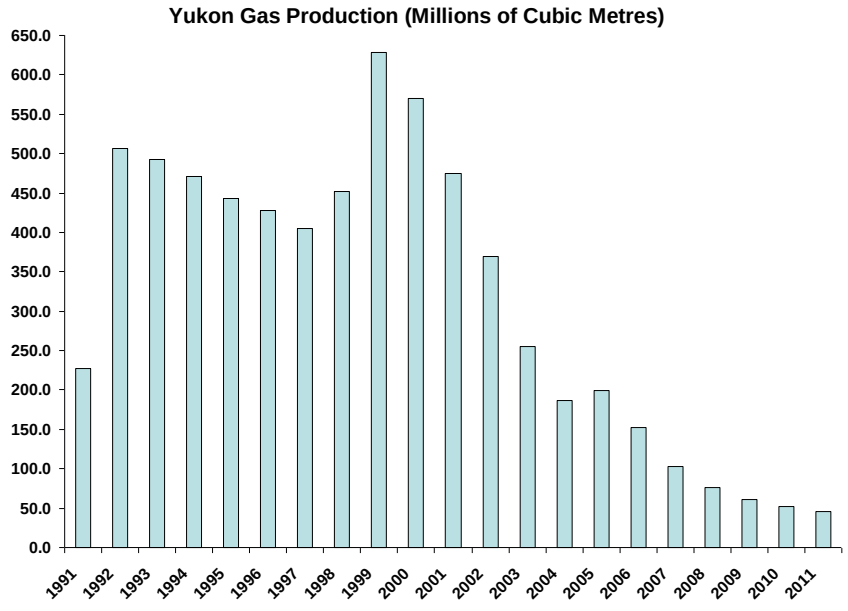
With the announcement of commercial production from the Wolverine mine in March 2012, Yukon now has three commercially producing mines. Benefitting primarily from higher production from the Wolverine mine, the value of Yukon's mineral production is expected to have grown for the seventh consecutive year in 2012, and total about $450 million, up from an estimated $402 million in 2011. While higher than 2011, the 2012 value of mineral production estimate is below the May 2012 forecast of $600 million. The downward revision is due to lower than expected production, as well as lower year-over-year prices for some minerals.

While, Yukon's mining sector has performed relatively well in 2012, the sector is not immune to global economic forces. Concerns of slowing growth in China, a sluggish U.S. recovery and ongoing economic turmoil in Europe has contributed to a volatile stock market and has seen many investors postpone their investment decisions, or decline to invest altogether. This weakened investment climate has contributed to lower exploration expenditures in 2012, as many junior mining companies found it difficult to raise funds to support exploration activities. With junior mining companies estimated to account for over 70 per cent of mining related spending in Yukon in every year for the period 2007 to 2012, current financing issues for junior mining companies is a concern for the local mining sector.

Even with the current global economic uncertainty, growth prospects for Yukon's mining sector are promising with six projects in permitting and a number at an advanced exploration or feasibility stage. For 2013, Alexco Resources has indicated that they are anticipating production from the Onek and Lucky Queen properties in 2013. Production from the Wolverine mine is also expected to increase in 2013 as the project achieves peak production. In terms of development, both Victoria Gold Corp. (Eagle Gold project) and Copper North Mining Corp. (Carmacks Copper project) have publically indicated a desire to begin development activities before the end of 2013.

Oil and Gas

Production at Kotaneelee, Yukon's only producing natural gas field, continued to decline in 2011 with production of 45.1 million cubic metres, down almost 13% from 51.6 million cubic metres in 2010. Kotaneelee has generally been on the decline since 1999, a normal trend for a field that is nearing the end of its productive life.



Source: Yukon Department of Energy, Mines & Resources

The Government of Yukon undertakes a disposition of oil and gas rights twice annually. The Spring 2012 Request for Postings (RFP) closed on January 18, 2012, and saw the Government of Yukon receive 12 RFPs for areas in southern Yukon in the Whitehorse Trough oil and gas basin. It was announced on April 12, 2012 that oil and gas exploration rights would not be issued in any of the 12 areas. This decision was made following the conclusion of a 60-day public review period and a technical review by the Government of Yukon.

For a number of years there has been discussion of the development of two proposed northern natural gas pipeline projects that if developed would have impacts on Yukon. Recent events seem to indicate that the development of either of these projects in the short-term is unlikely.

The Alaska Highway Pipeline Project would offer a source of natural gas to the United States' lower 48 states, with gas to be shipped via a 2,700-kilometre pipeline from Alaska, through Yukon and into Alberta. Recent development of shale gas resources in the United States has lessened the need for Alaskan natural gas and lowered the price of natural gas, and as such, alternative destinations for Alaskan gas are being considered. The project proponent, TransCanada PipeLines Limited, along with ExxonMobil, BP PLC, and ConocoPhillips, have committed to study the possibility of developing an alternative instate pipeline and liquefied natural gas (LNG) export plant. This project would be focused on production of LNG that would be targeted for Asian markets that have a growing demand

for natural gas products. Results of the evaluation of the LNG option for Alaskan gas will be important in determining if the Alaska Highway Pipeline Project will remain an option for development.

Development of the Mackenzie Gas Project in the near-term is uncertain. Abundant U.S. shale gas resources, natural gas prices at 10-year lows and cost escalations in the project itself were all noted as rationale for the recent announcement by the project lead, Imperial Oil, that the project had been put on hold and that budgets and staffing related to the project were being reduced. Beyond Imperial Oil, the partnership group that had been looking to develop the project includes Exxon Mobil Corp., ConnocoPhillips, Royal Dutch Shell PLC and the Aboriginal Pipeline Group. On April 2, 2012 the partnership issued a news release indicating that while the project was currently on hold, the project could be restarted if natural gas prices were to rebound sufficiently so as to improve the viability of the project.

There is optimism being generated about possible oil and natural gas development in Yukon coming out of the efforts of Northern Cross (Yukon) Limited to develop resources in the Eagle Plain area in northern Yukon. Development of natural gas resources would offer an opportunity for Yukon to reduce its dependency on the importation of petroleum products and provide a more cost-effective option to these petroleum products. With a substantial investment from CNOOC (China National Offshore Oil Corporation) International Inc., an affiliate of CNOOC Limited, one of China's largest independent oil and gas companies, Northern Cross has the capital to move forward with exploration work on its Yukon properties. Northern Cross has made a commitment of over $20 million for work on 15 exploration permits in the Eagle Plain area. Northern Cross is preparing a major exploration drilling program that is expected to begin in the summer of 2012, include the drilling of at least five wells and will likely last until the spring of 2013.

Economic growth in Yukon is increasing the demands for energy. Continued development of Yukon's mining sector in particular is placing additional pressure to identify adequate and cost-effective local sources of energy production. In response to these pressures the Department of Energy, Mines & Resources is examining the feasibility of developing Yukon's natural gas resources to meet Yukon's current and future energy demands.

Outlook for Oil and Gas

- Continue to evaluate the possibility of utilizing local gas resources to meet Yukon's current and future energy demands.

Oil & Gas - February 2013 Update: The Government of Yukon received two submissions to its most recent Oil and Gas Disposition Request for Postings which closed on January 16, 2013. Both request for oil and gas rights are for areas in the Eagle Plain basin. These requests are now subject to a 60 day public review period which is scheduled to close on March 28, 2013.

Production from the Kotaneelee gas field totaled 30.1 million cubic metres in 2012, down 33 per cent from 45.1 million cubic metres produced in 2011. In October 2012, EFL Overseas Inc. completed an acquisition of additional rights and interests in the Liard basin gas field and facilities in the Kotaneelee area from Nahanni Energy Inc. With the previous acquisition from Devon Canada EFL Overseas Inc. became the largest interest holder in the Kotaneelee with a general interest of 53.67 per cent and a working interest of 100 per cent in one gas well. EFL Overseas Inc. has indicated plans to pursue the acquisition of additional working interests in the Assets.

Northern Cross (Yukon) Limited continues to explore the development of resources in the Eagle Plain area in northern Yukon. Investment from CNOOC (China National Offshore Oil Corporation) International Inc., an affiliate of CNOOC Limited, one of China's largest independent oil and gas companies, has provided Northern Cross the capital to move forward with exploration work on its Eagle Plain properties. Northern Cross has made a commitment of over $20 million for work on 15 exploration permits and at the time of publication, two drill rigs were operational, with the expectation of 5-7 wells drilled by August 2013.

The Vuntut Gwitchin Development Corporation, on behalf of four northern First Nations, and with assistance from the Canadian Northern Economic Development Agency (CanNor), is also pursuing options to commercialize Eagle Plain gas. The feasibility study portion of the work has been completed and the four First Nations are now moving into the business planning portion of the project.

Yukon Energy Corporation is also assessing the use of natural gas to meet its short term (five year) generation requirements and as a transition fuel as it develops longer term renewable energy projects.

Tourism

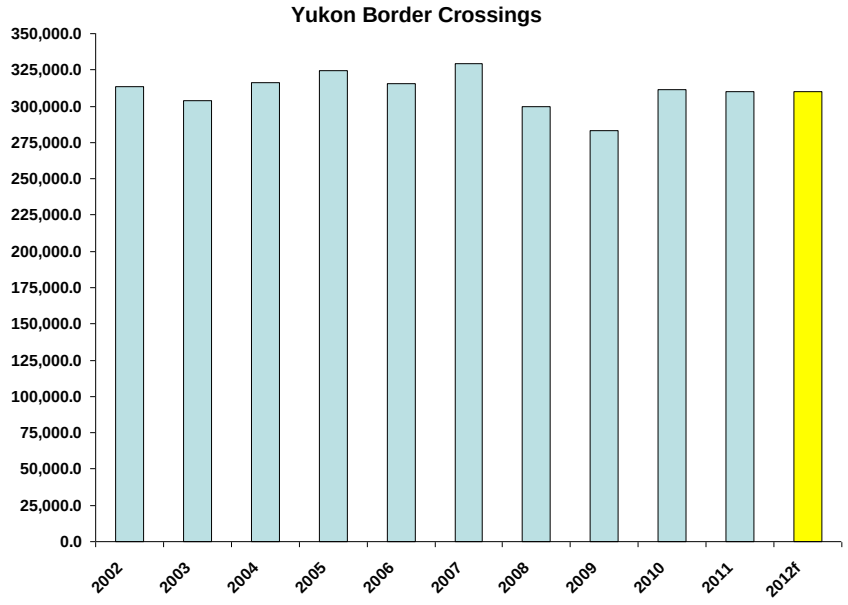
Recent tourism activity in Yukon has been steady, with annual international border crossings totaling about 310,000 in the past two years. Annual international border crossings of 309,863 were recorded in 2011, down slightly from 311,542 in 2010, but still above the almost 283,000 recorded for 2009.

Visitation via motorcoach totaled 122,205 in 2011, up 5.7% from 2010. Countering some of the gains in motorcoach visitation was a decline in visitation via private vehicle, which decreased 4.2% to 187,658. Higher year-over-year prices for fuel likely account for some of the decline in private vehicle traffic in 2011.

Recent shifts in visitation origin are consistent with what is being seen nationally, and is reflective of the current economic reality which is seeing advanced economies post weaker growth rates than those of emerging economies such as China or India.

Data for visitation by place of origin indicates that visitation from the U.S., Yukon's largest tourism market, was down 3.5% compared to the previous year, totaling 206,271 in 2011. While 2011 saw over 7,500 fewer visits from the U.S., visitation from the U.S. still accounted for two-thirds of all border crossings in 2011.

Non-U.S. visitation in 2011 increased to 103,592, up 6.0% from 2010. Increases in non-U.S. visitation were seen in all areas with visitation from other parts of Canada increasing 7.5% to 26,812 and foreign visitation increasing 5.1% to 33,329. Driving the foreign visitation was a strong increase in Asia/Pacific tourists, up 14.5% to 11,892.



Source: Yukon Department of Tourism & Culture; Yukon Department of Economic Development

At the Erik Nielsen Whitehorse International Airport, the total number of passengers arriving and departing increased by 7.7%, or 19,140 for a total of 267,442. The total for 2011 exceeded the previous high recorded in 2010, and it is the third consecutive year of increasing passenger volumes at the airport, potentially indicating a shift in how visitors will travel to the territory in the future.[3]

Given Yukon's well-established and unique tourism product, the outlook for visitation to Yukon remains generally positive. With that said, there are factors that have the potential to negatively impact visitation in the near-term.

The Canadian dollar has experienced a prolonged period of strength which is continuing into 2012. The Canadian dollar has been especially strong against the U.S. dollar, with the Canadian dollar averaging US$0.9997 year-to-date (to May 25, 2012). A strong Canadian

[3] Department of Tourism, Yukon Visitor Statistics, Year-End Report 2011

dollar increases the relative cost of travel to Canadian destinations, which could act as a deterrent to individuals who might travel to Yukon. A strong Canadian dollar could also impact visitation from other parts of Canada, as Canadians look to take advantage of a strong currency and travel to U.S. destinations or other regions where the Canadian dollar has appreciated against the local currency.

Economic and political uncertainty in the U.S. and abroad could also have some negative ramifications for travel to Yukon going forward. It has been a turbulent time for a number of countries with many countries' economies struggling in light of ongoing global economic concerns. Weakness in the economic recoveries of some countries, especially the U.S., could influence the global recovery and could negatively impact tourism. Continued economic and political uncertainty will likely cast a shadow on travel prospects going forward, which could have impacts on visitation to Yukon in the near-term.

Travel in 2012 could also be negatively impacted by high and increasing oil prices. Oil prices to May 25, 2012 averaged US$101.83 per barrel, 2.8% higher than in the same period of 2011. High oil prices are being reflected in higher gasoline prices as well with average year-to-date (to May 22, 2012) gasoline prices in Whitehorse are up 3.1% from the same period in 2011 to almost $1.31 per litre. Higher fuel prices increase the costs of operating a motor vehicle and also the operational costs for airlines. Given that the primary modes of transportation into Yukon are motor vehicles and aircraft, it is possible higher fuel prices and the subsequent higher costs of travel, could impact visitation to Yukon.

While risk factors exist, current expectations have visitation in 2012 being up slightly, with a forecast of 313,000 border crossings in 2012.

Outlook for Tourism

- Border crossings are expected to total about 313,000 in 2012, up slightly from approximately 310,000 in 2011.

Tourism – February 2013 Update: Data provided by the Department of Tourism & Culture has border crossings in the first ten months of 2012 at 315,440, up 3.8 per cent (11,517 visitors), versus the same period in 2011.

By mode of transportation increases in the January to October period were recorded in motorcoach visitation, up 9.9 per cent (12,067 visitors). Visitation via personal vehicle was down 550, representing a slight decline versus the first ten months of 2011.

By country of origin, the largest percentage increase in visitation was recorded from the United States which grew 4.9 per cent (9,881 visitors). Growth was also recorded in visitation from other parts of Canada, up 3.8 per cent (1,018 visitors) and foreign visitation, up 1.8 per cent (601 visitors). Visitation attributed to Yukon residents was on par with the same period of 2011 (up by 17 visitors).

U.S. visitation remains the largest contributor to Yukon visitation, accounting for over 67 per cent of all border crossings in the first ten months of 2012. After a decline of 3.5 per cent in 2011, U.S. visitation has rebounded well so far in 2012. Gains in 2012 may be a reflection of an improved economic situation for many U.S. residents, as the U.S. economy continues to recover from the recent global economic downturn.

The Department of Tourism & Culture has indicated that border crossings are expected to have grown to about 321,000 in 2012, 3.6 per cent higher than the 309,863 recorded in 2011 and well above the May 2012 forecast of 313,000.

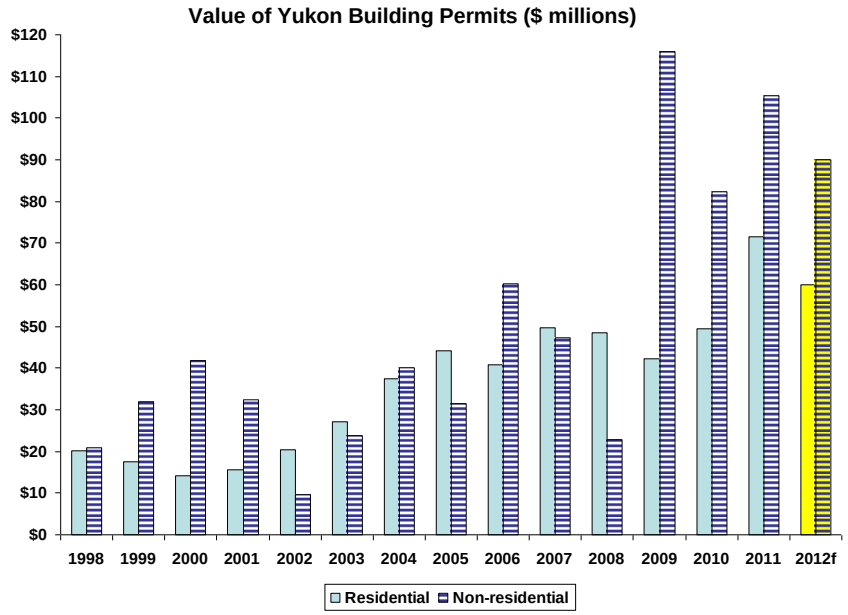
Beyond 2012, current expectations are for Yukon's tourism sector to continue to perform well. Assuming that the U.S. economy continues to recover and that the global economy does not fall into recession, visitation in 2013 is expected to total about 328,000 (Department of Tourism and Culture).

Construction

Reflecting the strong performance of Yukon's economy, a record value of building permits of $176.8 million were recorded in 2011. The 2011 value was over 34% higher than the $131.8 million reported for 2010. Gains in building permit value in 2011 stemmed primarily from growth in the value of residential building permits and institutional building permits.

Residential permit value reached $71.5 million in 2011, up almost 45% from the $49.4 million recorded in 2010. Strong residential construction in Whitehorse was the primary driver of residential permit value in 2011, with Whitehorse accounting for over $52 million in residential building permits.

The value of institutional permits totaled $70.8 million in 2011, up almost 50% from the $47.3 million posted in 2010. Major institutional projects such as the Watson Lake and Dawson City hospitals, development of a new wastewater treatment facility and district heating system in Dawson City, and water treatment facilities in Carcross and Ross River all contributed to strong growth in institutional permit value in 2011.



Source: Yukon Bureau of Statistics; Yukon Department of Economic Development

The expectation for 2012 is for construction activity to remain strong, with residential and institutional construction expected to once again be the primary drivers of permit value.

The most recent Government of Yukon budget included a significant commitment of funding in 2012-2013 to address land availability and housing needs. Of the almost $35 million noted to be directed towards these efforts, about half will be related to development of the Whistle Bend sub-division. Lots from phase one of the six phase project are scheduled to be ready for purchase by the fall of 2012 and will provide 93 single family, eight duplex and nine multi-family lots, along with one commercial and one school site. Upon completion, the Whistle Bend sub-division is expected to include 3,900 housing units and accommodate close to 8,000 people.

Beyond Whistle Bend, residential spending in 2012 will include the development of more Government of Yukon land in the downtown Whitehorse area, work related to the Grizzly Valley sub-division near Whitehorse and development of residential lots in Mayo and Watson Lake.

The Government of Yukon's 2012-2013 budget also included over $51 million in various transportation infrastructure projects. Included among these projects are:

- $15 million under the Shakwak project for the Haines Road and North Alaska Highway and a further $1 million from the Government of Yukon for the North Alaska Highway;
- Over $7 million for reconstruction of the Campbell Highway from km 10 to 190 and a further $1.5 million for surfacing;
- Over $7 million over the next two years to extend water and sewer services to the south commercial area at the Erik Nielson Whitehorse International Airport;

- $6 million for work related to rehabilitation and improvement of the Upper Liard Bridge;
- $2.6 million for reconstruction, Bituminous Surface Treatments and re-vegetation work on the Atlin Road;
- $2 million for reconstruction of the Takhini Hotsprings road;
- Over $1.8 million for improvement projects for the Erik Nielson Whitehorse International Airport including taxiway improvements, rehabilitation and the installation of a second bridge or jet way; and
- Over $1.8 million to address airside deficiencies at Yukon aerodromes outside Whitehorse.

In addition to transportation infrastructure and residential development the 2012-2013 Government of Yukon budget included funding commitments in a variety of other areas:

- $15 million under the Building Canada Plan for the construction of new wells, pump houses and treatment plants to improve the quality of drinking water in Burwash Landing, Carcross, Deep Creek, Dawson City, Haines Junction, Mendenhall, Old Crow, Ross River, Tagish and Teslin;
- Over $12 million under the Building Canada Plan as part of a multi-year program to improve water and wastewater systems in Faro, Haines Junction, Mayo and Watson Lake;
- Over $7 million for a new Emergency Response Centre in Whitehorse that will serve as the city's primary ambulance station;
- $7 million to construct a new recreation centre in Ross River;
- Over $4 million to develop a second-stage housing facility in Whitehorse;
- $3 million under the Canada Strategic Infrastructure Fund to complete the last phase of the Whitehorse Waterfront Development project;
- Over $2.3 million to build the Arrest Processing Unit, which will serve as a replacement for the RCMP detachment cells and offer prisoners access to 24-hour nursing and specially trained correctional staff; and
- Almost $1.3 million for replacement of the F.H. Collins Secondary School in Whitehorse.

The City of Whitehorse's most recent capital budget, released in December 2011, also notes several capital projects which will see notable spending in 2012. Most prominent among the spending included in the capital budget is $6.5 million in 2012 that is allocated for the extension of water and sewer services and associated road work in the Marwell area. New fire hydrants will also be added in some parts of Marwell to enhance fire protection. The city's most recent capital budget also includes 2012 expenditures of $4 million for expansion of the Porter Creek Reservoir and $3.8 million for reconstruction of Black Street, including work on roads, sidewalks and water and sewer lines. The budget also includes a total of $4.1 million to be directed towards the replacement of the Selkirk Pumphouse, a facility that currently handles Whitehorse's entire water supply. Of the $4.1 million, $2 million is planned to be spent in 2012 with the remaining $2.1 million to be spent in 2013.

Activity related to the mining sector should also continue to contribute to construction activity in Yukon. Even with the vast majority of the development work associated with Yukon's three commercially producing mining projects complete, these projects will continue to have expenditures associated with ongoing mine development. Capstone Mining Corp. has budgeted over $32 million for capital expenditures on work related to the Minto mine. Yukon Zinc Corp has also budgeted $10-$15 million for continued work on the Wolverine project. Further expenditures could be seen on the Bellekeno project as well as on the Victoria Gold project if development were to commence in the fourth quarter of 2012.

The current forecast for the value of building permits issued for 2012 is $150 million, which would be down from the record $177 million recorded in 2011, but above the long-term average.

Outlook for Construction

- The value of building permits in 2012 is expected to be $150 million, down from the record $177 million in 2011 but above the long-term average.

Construction - February 2013 Update: The forecast completed in May 2012 was for building permits in 2012 to total $150 million, down 15.2 per cent from the $176.8 million recorded in 2011. The expectation was for residential and institutional construction to be the primary contributors to total permit value in 2012

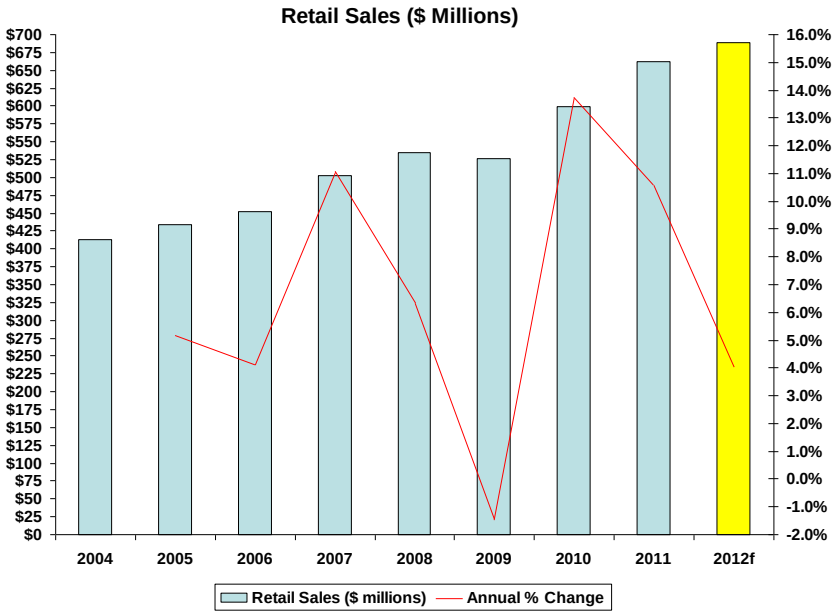
Data for 2012 indicate that building permit value fell well short of the May forecast. Total building permit value totaled $100.4 million in 2012, down 43.2 per cent from the $176.7 million recorded in 2011. While total building permit value was down, residential permit value was strong, totaling $65.7 million in 2012, accounting for over 65 per cent of total building permit value.

Declines in 2012 were noted in all areas of building permits, with lower value of government and institutional building permits accounting for the majority of the difference in total building permit value. After averaging almost $68 million in the three years prior to 2012, government and institutional permits totaled under $21 million in 2012, down 71.5 per cent from the $70.7 million recorded in 2012. Lower government and institutional permits account for 66 per cent of the total decline in total building permits of $76.3 million.

Going forward expenditures related to the reclamation of the Faro mine, further development of existing mines and spending related to new mining startups are expected to contribute to construction activity. Further expenditures related to residential construction, in particular related to the Whistle Bend subdivision in Whitehorse, as well as construction of the F.H. Collins School, is also expected to contribute to construction activity in the near-term.

Trade

The value of retail sales in Yukon totaled a record $662 million in 2011, up 10.6% from $599 million in 2010. Strong economic activity related to mining development, increased employment, higher population and higher year-over-year fuel prices are all considered contributing factors to retail sales growth in 2011.



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Department of Economic Development

The value of retail sales for 'other retail stores' exceeded $400 million in 2011, up from $378.7 million in 2010. Contributing to the higher value of sales were higher year-over-year fuel prices, which positively impacted the value of sales from gasoline stations.

Increases in sales were also recorded in other retail sale categories in 2011. Sales from 'food and beverage stores' increased 4.4% to $195.7 million in 2011, up from $187.5 million in 2010. Sales from 'clothing and clothing accessories stores' also increased 5.9% to $18.4 million in 2011, up from $17.4 million in 2010.

Strong oil prices are expected to continue to impact fuel prices in 2012 and will likely continue to impact the value of retail sales. Year-to-date (to May 25, 2012) oil prices have averaged almost US$102 per barrel, 2.8% higher than in the same period in 2011. Higher oil prices are contributing to higher fuel prices with year-to-date (to May 22, 2012) gasoline prices in Whitehorse 3.1% higher than the same time in 2010. Fuel prices are expected to post a year-over-year increase in 2012, which could see costs of shipping goods to Whitehorse increase as a result of the higher fuel costs. If passed onto consumers, higher fuel costs could also positively impact retail sales.

Rising fuel prices are not expected to be the only driver of retail sales in 2012. Continued economic growth, stemming primarily from activities related to the mining sector could also positively impact retail sales in 2012. A growing population, increases in the number of people employed and higher household incomes should all contribute to growth in retail sales in 2012.

Overall, it is expected that retail sales will grow to approximately $690 million in 2012.

Outlook for Retail Sales

- Retail sales are expected to continue to benefit from a strong local economy and total approximately $690 million in 2012, representing a 4% increase from 2011.

Trade – February 2013 Update: Retail sales in the first eleven months of 2012 totaled almost $617 million, up 2.5 per cent from $602 million recorded in the same period in 2011.

Food and Beverage Stores, the largest segment of retail sales in Yukon at about 30 per cent of total sales, is reported to have increased by 2.5 per cent in the first eleven months of 2012 when compared to the same period in 2011. Strong growth in sales was recorded by Gasoline Stations; which recorded gains of 10.7 per cent. Sales from Gasoline Stations accounted for over 16 per cent of all sales in the first eleven months of 2012. Growth was also recorded in Food and Beverage Stores (2.5 per cent) and Health and Personal Care Stores (3.0 per cent).

Declines in 2012 were noted in Clothing and Clothing Accessories Stores and Building Material and Garden Equipment and Supplies Dealers which fell 7.0 per cent and 0.9 per cent respectively. Sales from these two categories together accounted for over 10 per cent of total sales in the first eleven months of 2012.

Given year-to-date growth in retail sales, the 2012 total will fall below the May forecast, but total over $675 million, up by over 2 per cent from $662.2 million in 2011.

Looking forward to 2013, expectations for continued economic growth are expected to contribute to further gains in retail activity with sales anticipated to approach $700 million.

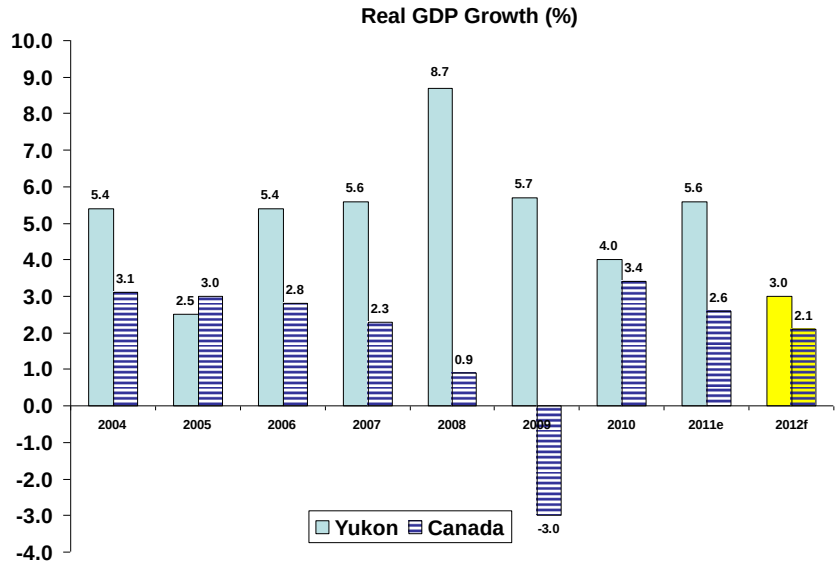
Yukon Outlook – Economic Indicators

Economic Growth (Gross Domestic Product)

On April 27, 2012, Statistics Canada released preliminary 2011 real GDP data by industry for provinces and territories. It is estimated that Yukon's real GDP in 2011 totaled $1.776 billion, up 5.6% from $1.681 billion in 2010. Yukon's estimated growth for 2011 was more than double the national growth rate of 2.6% and ranked second among all Canadian jurisdictions, behind only Nunavut at an estimated growth rate of 7.7%. With estimated growth of 5.2%, Alberta posted the strongest growth among all the provinces.

Statistics Canada attributed Yukon's 2011 real GDP growth primarily to activities related to Yukon's growing mining sector. It was noted that gains in output of support activities to mining and oil and gas extraction, record levels of mineral exploration and higher mineral production due to the opening of the Bellekeno mine were all contributing factors to real GDP growth in 2011. Statistics Canada also highlighted a 21% growth in construction output, a 6.6% growth in retail trade and a 4.7% growth in the finance, insurance and real estate sector as contributing to overall growth in Yukon's 2011 real GDP.

With growth in 2011, Yukon has posted eight consecutive years of real GDP growth, with Yukon's growth rate exceeded the national average in seven of the eight years.



Source: Yukon Bureau of Statistics; Statistics Canada; International Monetary Fund; Yukon Department of Economic Development

The development of Yukon's mining sector has been the primary driver of real GDP growth in recent years, with Yukon's economy benefitting from expenditures related to mineral exploration and development and the addition of mineral production from new mining projects. Significant construction activity in Yukon has also contributed to economic growth in recent years.

The expectation for 2012 is that Yukon will post gains in real GDP for the ninth consecutive year as mining and construction related activities continue to contribute to Yukon's economy. The current forecast for 2012 real GDP is for growth of upwards of 3%. The addition of commercial mineral production from the Wolverine mine, supported by continued construction activity and tourism-related activity, is expected to contribute to real GDP growth in 2012.

The Conference Board of Canada's latest economic forecast for the three Canadian territories was released in March 2012.[4] The current Yukon forecast is for 2.9% Real GDP growth for 2012. The Conference Board of Canada releases economic forecasts for the three territories twice annually and a revision to the March estimate is expected this summer.

Outlook for GDP

- Yukon's real GDP is expected to increase by upwards of 3% in 2012, with growth related primarily to increased mineral production.

[4] *Territorial Outlook, Winter 2012*, Conference Board of Canada, Centre for the North

Gross Domestic Product - February 2013 Update: Statistics Canada's revised estimates for real GDP for the provinces and territories, released on November 19, 2012, indicate that Yukon's real GDP grew 6.5 per cent in 2011 to $2.407 billion*. Yukon's growth estimate for 2011 was more than double the national growth rate of 2.6 per cent and the highest growth rate of any Canadian jurisdiction.

Statistics Canada noted a number of areas that helped contribute to the strong growth in 2011. A 22.0 per cent increase in Yukon exports, more than double the pace of growth in 2010, was a strong contributor to growth in 2011. Due to the strength of outlays on mineral exploration business investment in Yukon rose 6.5 per cent in 2011 which also contributed to real GDP gains. An increase of 4.5 per cent in Consumer spending was the strongest growth in the country, a reflection of higher household spending on services, in particular rents, air transportation and food and non-alcoholic beverage services.

The December 14, 2012 Statistics Canada real GDP by industry release also noted a gain of 6.5 per cent in Yukon's real GDP. Gains in Mining, Quarrying and Oil and Gas Extraction was the primary contributor to total real GDP growth in 2011, accounting for over 80 per cent of all estimated gains in 2011.

In May 2012 the Department of Economic Development forecasted growth upwards of 3 per cent in 2012. Current expectations are that real GDP growth in 2012 will likely be in the range of 2 to 3 per cent.

The Conference Board of Canada's Territorial Outlook Summer 2012 publication includes a forecast of 3.7 per cent for Yukon real GDP for 2011.

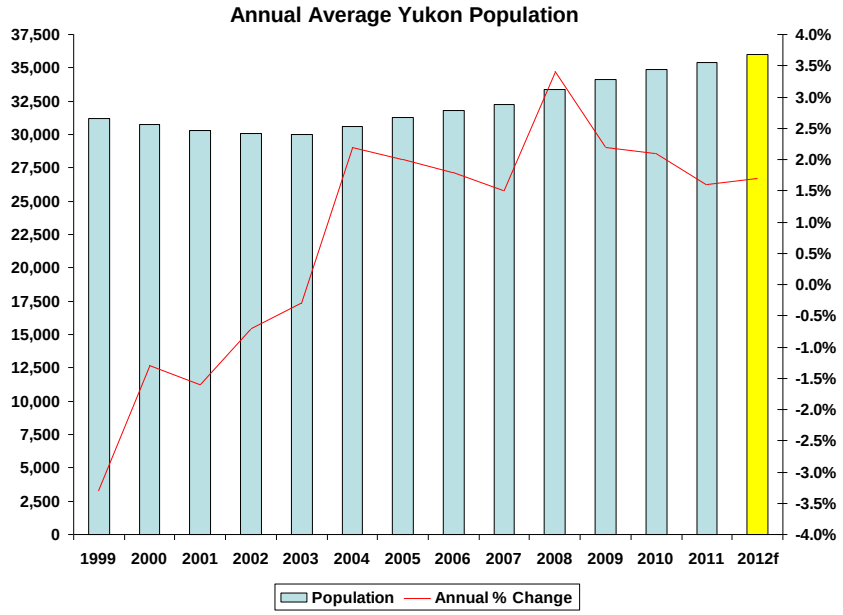
Early expectations for 2013 are for Yukon's real GDP to grow for a tenth consecutive year, but likely below levels recorded in recent years. Uncertainty related to the level of construction activity, mining project development, and exploration expenditures are tempering initial growth expectations for 2013.

*Periodically, the provincial and territorial economic accounts undergo historical revisions, which are much broader in scope than the regular annual revisions. These revisions are reserved for incorporating updated international national accounting standards, as well as conceptual, classification, presentational and major statistical changes. Statistics Canada's November 2012 release included revisions back to 2007, with further revisions back to 1981 to be released in 2013. Real dollar figures are now expressed in 2007 dollars, versus the previous 2002 dollars.

Population

Yukon's annual average population grew by 544 to 35,391 in 2011, representing a 1.6% increase over the previous year. This is the eighth straight year of population growth for Yukon and marks the highest annual average population since the beginning of the Yukon Census.[5]

[5] Accurate population estimates for the gold rush era are not available. However, the first census population estimate for Yukon was conducted in 1901 when the population was recorded at 27,219.



Source: Yukon Bureau of Statistics; Yukon Department of Health & Social Services; Yukon Department of Economic Development

Comparing December 2011 to December 2010, Yukon's population grew 1,133 to 35,800, an increase of 3.3%. Growth was concentrated in Whitehorse where the population increased by 886 (3.4%) to 27,190. The population of Whitehorse accounts for over 75% of Yukon's total population.

Over the same period, population growth was recorded in fourteen communities, with declines only in Watson Lake (-15) and Tagish (-1). The population of Burwash Landing was unchanged. Outside of Whitehorse the largest increases in population were recorded in Dawson City, Marsh Lake and Carmacks, which posted population gains of 78, 42 and 35, respectively.

Yukon's demographic situation is similar to the national story with both the populations of Yukon and Canada generally getting older. The population of mid-to-retirement aged Yukoners, aged 45-64, totaled 11,499 in December 2011, 1.7% higher than the December 2010 total. Accounting for over 32% of Yukon's total population in December 2011, the 45-64 segment of Yukon's population has exceeded 30% of the total population for seven consecutive years.

The number of post-retirement age residents (65 and older) has also been increasing in recent years. As of December 2011, 3,291 Yukon residents were 65 or older, accounting for over 9% of Yukon's total population. Only ten years ago, this segment of the population accounted for only about 6% of the population, with only 1,850 post-retirement age people living in Yukon.

While it is the case that Yukon has an aging population, the number of individuals 19 years of age or younger actually increased to 7,748 in December 2011, up from 7,604 in December

2010. This marked the first such increase since 2004. Optimism related to a strong local economy could account for the increase, as young people and young families may be looking to capitalize on employment and business opportunities in the territory.

Optimism related to a generally healthy economy could also explain the continued growth in Yukon's 'working age' population (15-64). This segment of the population totaled 26,887 in December 2011, up 2.8% from December 2010. More than half (13,261) of the 'working age' population falls within the ages of 20-44, with this segment of the population posting strong growth in the last two years, with annual increases of over 4.5% in both 2011 and 2010. Notable increases in 2011 were also recorded in the 25-29 range (7.6%) and the 30-34 range (6.8%).

On average, the population of Yukon is expected to total 36,000 in 2012, representing a 1.7% increase over 2011 and marking the ninth straight year of population increase.

Outlook for Population

- Yukon's average population is forecast to increase to 36,000 in 2012, marking the ninth straight year of population growth.

Population - February 2013 Update: Revised population estimates by the Yukon Bureau of Statistics show Yukon's average annual population in 2011was 35,246, an increase of 1.1 per cent over 34,847 in 2010. This was a downward revision from the 2011 annual average reported in the May Outlook of 35,391, and down from a preliminary annual average increase of 1.6 per cent.

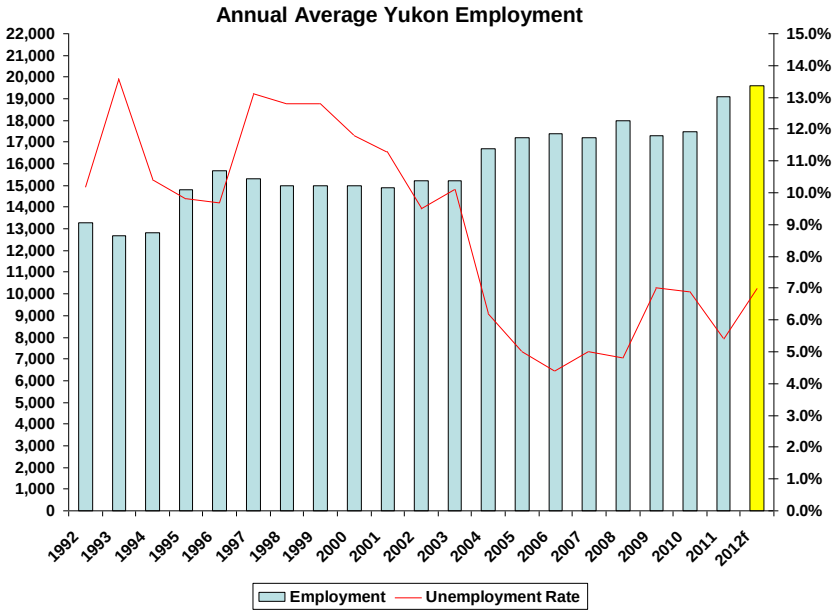
Yukon's average population to June 2012 is estimated at 35,723, an increase of 1.4 per cent over the revised 2011 average. Working age population data from the Yukon Labour Force Survey indicate continued population growth in the second half of the year.

The Yukon population in 2012 is now expected to average just short of the May forecast of 36,000. Early expectations for 2013 are for further gains, with the population expected to grow to an average of approximately 36,500.

Labour Force

The Yukon Labour Force Survey, as conducted by Statistics Canada, reported the average Yukon labour force at 20,200 in 2011, almost 7% higher than the figure reported for 2010. The average number of employed in Yukon was 19,100, up 9.1% from the 2010 average of 17,500. The survey also reported the average number of unemployed in 2011 at 1,100, down over 15% from 2010.

The average Yukon unemployment rate was reported as 5.4% for 2011, down from 6.9% in 2010. The 2011 unemployment rate for Yukon was amongst the lowest in the country and well below the national average of 7.5%.[6]



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Labour Force Survey

Yukon Labour Force Survey data for the first four months of 2012 notes across-the-board increases for key labour force statistics. From January to April, Yukon's labour force has averaged 20,600, 4.4% higher than in the same period of 2011. The average number of people employed in the first four months of 2012 was 19,150, up 375 from the same period of 2011. Gains have also been noted in the number of people unemployed and the unemployment rate in the first four months of 2012, with the average number of unemployed increasing by 525 to 1,450 and the unemployment rate increasing from an average of 4.7% in the first four months of 2011 to an average of 7% in the first four months of 2012.

The higher unemployment rate in early 2012 appears to be at odds with the recent performance of other key economic indicators, as Yukon continues to experience continued high levels of mining-related activity, retail trade and construction activity. Recent increases in the unemployment rate could be attributable to the relatively small sample size used for the Yukon Labour Force Survey, which can often be subject to volatility. Yukon's labour force has also seen significant recent growth, which is often the case for an economy that is performing well. Recent labour force growth outperforming recent employment gains has also contributed to an increase in the unemployment rate in recent months.

[6] Methodological differences exist between the Labour Force Survey used for the Territories and that of the Labour Force Survey utilized for the Provinces. Sample design, rotation pattern and reliability criteria are different in the three territories from those in the ten provinces.

Generally, Yukon's economic fundamentals appear to be strong and the expectation is that continued economic growth driven by continued high levels of construction and resource sector activity should contribute to lower unemployment rates in the coming months. The forecast for 2012 has Yukon's average labour force increasing from 20,200 to 21,000, an increase of 4%. Yukon employment is also anticipated to post growth in 2012, with the current forecast for an increase of just over 2.5% to 19,600. The number of unemployed is expected to increase to 1,400 in 2012, up from 1,100 in 2011. With labour force growth expected to outpace growth in employment, the average unemployment rate for 2012 is expected to increase to 6.5%-7.0%.

Outlook for Labour Force

- Yukon's labour force is expected to continue to post gains in 2012, with the labour force expected to grow to a record 21,000. The number of people employed is also expected to increase to a record 19,600.
- With labour force growth expected to outpace employment growth in 2012, the unemployment rate is expected to increase to 6.5%-7.0%.
- Opportunities associated with resource development activities and high levels of construction activity will continue to support employment gains in 2012.

Labour Force - February 2013 Update: Following a record average of 19,100 employed in 2011, Yukon's average employment in 2012 fell to 18,900. While down from 2011, Yukon employment in 2012 recorded the second highest level in history. Yukon's labour force averaged a new record in 2012, growing to 20,400, up from the previous record of 20,200 in 2011.

With a growing labour force and a slight decline in average employment, 2012 saw Yukon's unemployment rate increase to an average of 6.9 per cent, up from 5.4 per cent in 2011.

Further economic growth is expected to support gains in both employment and the labour force in 2013. Current expectations have employment growing to 19,100 and the labour force growing to 20,600.

Consumer Prices

The Whitehorse Consumer Price Index (CPI)[7] for 2011 increased by 3.0%, higher than the 0.8% increase recorded in 2010. The 3.0% annual increase in the Whitehorse CPI is the second highest increase since 1992, and followed two years of very low inflation in 2009 and 2010. Looking at national performance, Canada's CPI increased by a similar 2.9% in 2011.

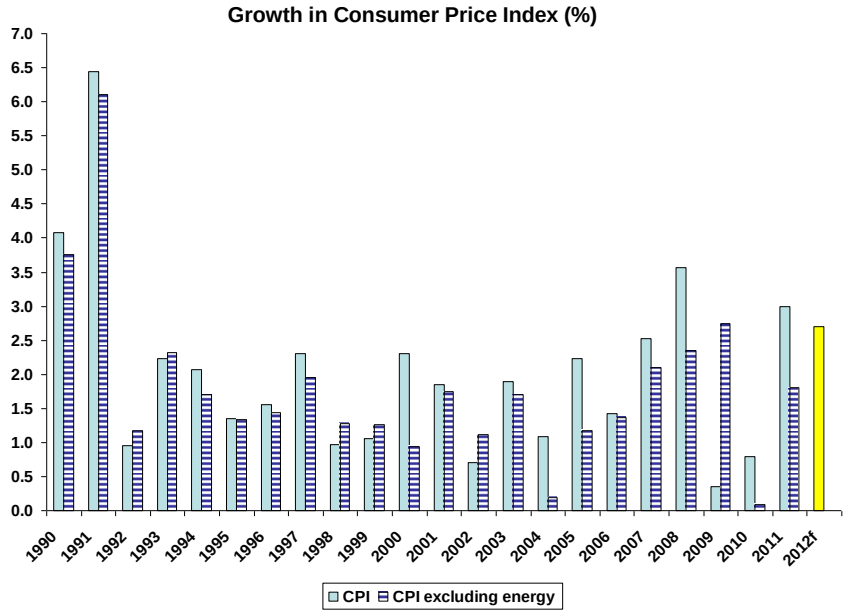
Contributing to Whitehorse's CPI growth in 2011 was the persistence of strong prices for crude oil, which contributed to higher fuel prices at the consumer level. Comparing 2011 to 2010, the price of Home Heating Fuel Oils and other oils is reported to have increased by 21% and the price of Gasoline over the same period is reported to have increased by 15%.

[7] Consumer Price Index data is only available in Yukon for Whitehorse.

The Energy component of Whitehorse CPI increased by over 13% in 2011, partly a reflection of higher crude oil prices.

Looking at the various components of CPI for Whitehorse, only Clothing and Footwear (down 0.9%) did not post an increase in 2011. On a percentage basis, the largest increases were seen in Gasoline (14.7%), Transportation (5.0%) and Shelter (4.4%). All these components were impacted by higher oil and fuel prices, contributing to much of the increases noted for these components in 2011.

Other components of CPI that saw increases in 2011 included Food (2.6%), Alcoholic Beverages & Tobacco Products(2.3%), Household Operations, Furnishings & Equipment (0.9%), Health & Personal Care (0.6%) and Recreation, Education & Reading (0.1%).



Source: Yukon Bureau of Statistics; Statistics Canada; Yukon Department of Economic Development

Expectations for 2012 are that prices will continue to be impacted by high and increasing fuel prices. Year-to-date (to May 25, 2012) oil prices have averaged almost $102 per barrel, almost 3% higher than the $99 per barrel averaged in the same period of 2011. Many forecasters are expecting oil prices to remain high throughout 2012, with BMO Capital Markets Economics forecasting oil to average $100 per barrel and TD Economics calling for oil to average just over $100 per barrel.

The impacts of higher year-over-year prices for fuel have been reflected in Whitehorse's average CPI in the first four months of 2012, which has increased 2.7% versus the same period in 2011. The Gasoline component of Whitehorse's CPI was up 4.7% in the first four months of 2012, while the overall Energy component increased by 5.5%.

The current forecast from the Department of Economic Development is for Whitehorse CPI to increase 2.5% in 2012. This forecast represents the expectation that oil prices will likely continue to be strong throughout 2012, contributing to year-over-year growth in fuel costs. Higher fuel prices could lead to price increases in other areas as increased fuel prices trickle through the economy and increase costs.

Outlook for the Consumer Price Index

- Inflation in Whitehorse in 2012 is expected to average 2.5%, slightly lower than the 3.0% recorded in 2011.

Consumer Prices - February 2013 Update: Consumer inflation averaged 2.3 per cent in Whitehorse in 2012, slightly below the May 2012 forecast of 2.5 per cent and below the 3.0 per cent average observed for all of 2011.

Energy continues to be a key driver of inflation in Whitehorse, with the 2012 average up 3.9 per cent over the 2011 average. Fuel oil has been reported as increasing by 4.5 per cent in this period and electricity has increased by 4.1 per cent.

In addition, the gasoline component of the Consumer Price index is reported to have increased by 3.6 per cent over 2011 figures. Gains in 2012 have also been reported in Shelter and Food which have increased 3.4 per cent and 2.6 per cent respectively.

Looking forward to 2013, national forecasts are predicting a slowing of inflation over the year with a slowing housing market but increases in food prices. It expected that inflation should average 2.0 per cent overall in Whitehorse in 2013, slightly higher than the national average.

Key Economic Indicators Summary Table

Indicator	*2011*	*2012f*	*2012f update*	*2013pf*
Population, Prices, Rates				
Population	35,246	36,000	36,000 (f)	36,500
Inflation Rate^	3.0%	2.5%	2.3%	2.0%
Overnight Rate	1.00%	1.00%	1.00%	1.00%
Canada/U.S. Exchange Rate	$1.012	$1.010	$1.001	$1.009
Employment†				
Labour Force	20,200	21,000	20,400	20,600
Employment	19,100	19,600	18,900	19,100
Unemployed	1,100	1,400	1,400	1,500
Unemployment Rate	5.4%	6.5%-7.0%	6.9%	7.3%
Economic Output				
Real Gross Domestic Product (millions of chained 2007 dollars)	$2,407 (r)	$2,480	$2,455-$2,480 (f)	$2,510
Real GDP Growth Rate	6.5%	3.0%	2.0-3.0% (f)	2.0%
Commodity Prices~				
Gold ($US/oz)	$1,570	$1,675	$1,668	$1,708
Silver ($US/oz)	$35.11	$34.25	$31.15	$31.83
Zinc ($US/lb)	$0.99	$0.95	$0.88	$0.95
Copper ($US/lb)	$4.00	$3.85	$3.61	$3.61
Oil - WTI ($US/bbl)	$95.08	$100	$94.20	$94.00
Natural Gas ($US/MMBTU) NYMEX	$4.00	$2.15	$2.75	$3.60
Mining				
Value of Mineral Production	$401.8 million (p)	$600 million	$450 million (f)	$550-$600 million
Exploration Expenditures	$331.7 million (r)	$160-$200 million	$150 million (f)	--
Development Expenditures	$150 million (e)	$70 million	$98 million (f)	--
Oil and Gas				
Natural Gas Prod'n Volume - m3	45,143,100	--	30,131,300	--
Construction				
Permitted Building Construction	$176.8 million	$150 million	$100.4 million	$125 million
Trade				
Value of Retail Sales	$662.2 million	$690 million	$675 million (f)	$690-$700 million
Tourism				
Non-resident Border Crossings+	309,863	313,000	321,000 (f)	328,000

f = forecast, pf = preliminary forecast, e = estimate, p = preliminary estimate, r = revised, -- = not available
^ CPI increase for Whitehorse only
† annual averages – totals may not total due to rounding
~ annual averages
+ as reported by the Department of Tourism & Culture

Data Sources for Key Economic Indicators Summary Table

Indicator	*Source*
Population	Yukon Bureau of Statistics, Yukon Population Estimates, Yukon Department of Economic Development
Inflation (Consumer Price Index)	Statistics Canada, Consumer Price Index, Yukon Department of Economic Development
Overnight Rate	Bank of Canada (average daily rate), BMO Capital Markets
Canada/U.S. Exchange Rate	Bank of Canada (average daily noon rate), BMO Capital Markets
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Economic Development
Economic Output (GDP)	Statistics Canada, Provincial Economic Accounts , Yukon Department of Economic Development
Commodity Prices	BMO Capital Markets
Value of Mineral Production	Natural Resources Canada Minerals and Mining Statistics Division, Yukon Department of Economic Development
Mineral Exploration Expenditures	Natural Resources Canada Minerals and Mining Statistics Division , Yukon Department of Economic Development
Mine Development Expenditures	Yukon Department of Energy, Mines & Resources, Yukon Department of Economic Development
Natural Gas Production Volume	Yukon Department of Mines & Energy
Tourism Visitation	Yukon Department of Tourism & Culture, Yukon Department of Economic Development
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Economic Development
Retail Trade	Statistics Canada, Yukon Department of Economic Development

YUB-YECL-57

Reference: Demand-side management impacts beyond 2013, YECL Application, page 2-5

The increase in UPC relating to electric space heating, however, is not expected to be extended beyond 2013, as it is expected to be offset by a reduction in consumption due to the demand side management program. Attachments 1 to 21 show the historical data as well as the regression results.

Request:

Please provide the excel spreadsheet(s) with all formulas intact for Attachments 2 to 21, of Section 2 in the application.

Response:

Please refer to YUB-YECL-57 Attachments 1 to 21.

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1334.11	1165.70	1,295	
Feb-98	1071.75	719.10	1,134	
Mar-98	1027.75	756.60	1,043	
Apr-98	902.89	458.60	921	
May-98	787.72	270.60	815	
Jun-98	696.64	119.50	719	
Jul-98	627.52	111.60	628	
Aug-98	604.15	189.20	592	
Sep-98	706.17	327.80	699	
Oct-98	780.59	557.70	772	
Nov-98	922.54	792.30	936	
Dec-98	970.68	1051.80	927	
Jan-99	1383.18	1183.10	1,334	
Feb-99	1164.46	976.40	1,088	
Mar-99	1040.97	734.00	1,069	
Apr-99	944.37	508.80	936	
May-99	811.83	391.90	774	
Jun-99	754.75	153.90	758	
Jul-99	646.43	108.60	649	
Aug-99	610.64	145.70	621	
Sep-99	697.48	311.20	700	
Oct-99	763.70	499.80	786	
Nov-99	881.73	792.50	895	
Dec-99	994.21	844.00	1,062	
Jan-00	1264.66	1082.90	1,270	
Feb-00	1036.07	735.20	1,090	
Mar-00	918.53	659.20	986	
Apr-00	854.15	515.60	842	
May-00	846.79	382.00	815	
Jun-00	731.77	172.50	725	
Jul-00	656.21	142.10	641	
Aug-00	620.05	219.90	591	
Sep-00	733.99	354.20	713	
Oct-00	787.21	539.20	788	
Nov-00	884.41	691.20	952	
Dec-00	940.26	977.80	936	
Jan-01	1185.33	722.70	1,384	
Feb-01	938.26	864.10	922	
Mar-01	987.72	765.30	998	
Apr-01	867.85	506.80	860	
May-01	816.38	390.40	780	
Jun-01	763.40	167.30	760	
Jul-01	657.29	139.60	643	
Aug-01	598.61	139.60	613	
Sep-01	660.89	309.00	664	
Oct-01	754.64	573.40	737	
Nov-01	904.51	818.00	904	
Dec-01	1056.40	1094.60	989	
Jan-02	1223.01	935.60	1,307	
Feb-02	1013.30	824.60	1,019	
Mar-02	997.99	921.10	925	
Apr-02	990.09	653.30	904	
May-02	798.77	361.60	777	
Jun-02	707.08	175.60	699	
Jul-02	642.71	130.90	633	
Aug-02	648.08	182.80	639	
Sep-02	680.33	314.40	681	
Oct-02	758.56	444.30	811	
Nov-02	873.29	582.60	999	
Dec-02	898.43	845.20	966	

Yukon Electrical Company Limited
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Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1202.44	989.10	1,258	
Feb-03	995.15	756.60	1,037	
Mar-03	985.34	834.50	959	
Apr-03	892.59	514.30	881	
May-03	790.52	363.70	768	
Jun-03	749.45	192.80	732	
Jul-03	657.75	84.40	673	
Aug-03	617.42	180.60	609	
Sep-03	709.08	359.20	685	
Oct-03	726.71	466.70	767	
Nov-03	910.68	874.60	880	
Dec-03	1072.98	911.60	1,104	
Jan-04	1245.81	1257.90	1,157	
Feb-04	1092.27	697.20	1,166	
Mar-04	923.71	753.50	941	
Apr-04	948.79	466.60	963	
May-04	751.60	272.50	778	
Jun-04	711.26	83.70	753	
Jul-04	667.46	74.20	688	
Aug-04	607.29	101.70	642	
Sep-04	669.67	367.50	642	
Oct-04	761.52	540.50	762	
Nov-04	897.87	719.80	950	
Dec-04	1015.36	899.50	1,053	
Jan-05	1277.77	1165.80	1,238	
Feb-05	1107.70	795.20	1,129	
Mar-05	922.86	613.70	1,015	
Apr-05	906.16	453.30	928	
May-05	734.86	256.60	770	
Jun-05	705.13	154.40	709	
Jul-05	660.11	132.60	650	
Aug-05	621.38	150.80	629	
Sep-05	741.98	299.30	751	
Oct-05	733.74	534.60	737	
Nov-05	921.61	762.60	951	
Dec-05	967.23	794.40	1,062	
Jan-06	1196.53	1096.20	1,195	
Feb-06	1043.82	821.30	1,051	
Mar-06	1072.57	906.30	1,007	
Apr-06	933.65	519.10	920	
May-06	801.77	346.90	788	
Jun-06	726.49	173.10	720	
Jul-06	704.17	118.40	701	
Aug-06	635.06	201.60	616	
Sep-06	736.28	295.70	747	
Oct-06	795.22	520.50	806	
Nov-06	938.75	1162.20	753	
Dec-06	1130.58	824.30	1,209	
Jan-07	1245.66	912.00	1,343	
Feb-07	1050.91	998.80	962	
Mar-07	1139.27	954.20	1,048	
Apr-07	985.39	511.90	975	
May-07	735.33	322.10	735	
Jun-07	719.79	140.50	731	
Jul-07	702.49	102.30	708	
Aug-07	597.33	154.20	604	
Sep-07	688.79	308.40	692	
Oct-07	754.77	543.70	753	
Nov-07	922.64	724.60	972	
Dec-07	995.15	1069.50	942	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Whitehorse Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	
Jan-08	1298.44	1113.80	1,287		
Feb-08	1185.79	954.60	1,121		
Mar-08	1011.53	734.70	1,039		
Apr-08	942.12	517.30	929		
May-08	788.52	307.90	796		
Jun-08	696.47	225.60	662		
Jul-08	680.93	173.40	648		
Aug-08	700.97	187.70	689		
Sep-08	700.67	318.70	699		
Oct-08	732.64	563.00	721		
Nov-08	984.81	782.50	1,003		
Dec-08	1011.40	1186.20	895		
Jan-09	1528.55	1137.90	1,504		
Feb-09	1122.38	955.40	1,057		
Mar-09	1093.54	868.50	1,049		
Apr-09	945.55	515.20	934		
May-09	773.10	331.20	768		
Jun-09	704.15	144.10	713		
Jul-09	702.59	62.50	730		
Aug-09	627.45	158.30	632		
Sep-09	719.71	306.10	725		
Oct-09	771.84	541.80	771		
Nov-09	953.63	781.50	973		
Dec-09	1013.21	943.40	1,027	10882.60	
Jan-10	1345.94	991.10	1,401		
Feb-10	1012.55	679.20	1,096		
Mar-10	940.25	656.00	1,010		
Apr-10	944.91	461.20	962		
May-10	795.15	292.00	811		
Jun-10	719.19	171.90	713		
Jul-10	685.61	117.30	683		
Aug-10	627.66	146.20	638		
Sep-10	720.70	332.40	711		
Oct-10	821.83	520.40	833		
Nov-10	904.24	717.60	958		
Dec-10	1057.11	1162.50	953	10770.18	
Jan-11	1436.52	1010.20	1,481		
Feb-11	1129.49	905.60	1,091		
Mar-11	1256.14	901.70	1,193		
Apr-11	955.17	511.20	945		
May-11	892.99	296.20	907		
Jun-11	743.84	161.00	744		
Jul-11	677.48	127.80	670		
Aug-11	647.93	217.90	620		
Sep-11	737.64	328.50	731		
Nov-11	831.75	513.30	847		
Nov-11	943.59	936.25	879		
Dec-11	1136.92	775.10	1,242	11349.30	
Jan-12	1356.98	1118.10	1,343		
Feb-12	1170.51	707.50	1,239		
Mar-12	1098.22	756.20	1,114		
Apr-12	930.47	450.60	953		
May-12	835.03	350.80	820		
Jun-12	770.21	200.00	749		
Jul-12	708.91	140.10	694		
Aug-12	677.42	157.90	682		
Sep-12	695.14	287.15	710		
Oct-12	802.64	631.40	754		
Nov-12	1011.59	969.60	929		
Dec-12	1262.76	1196.80	1,141	11128.22	0.7%
2013-F				11,211	
2014-F				11,211	
2015-F				11,211	

Yukon Electrical Company Limited
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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1347.45	1165.70	1,299	
Feb-98	914.75	719.10	991	
Mar-98	850.95	756.60	870	
Apr-98	789.18	458.60	812	
May-98	794.14	270.60	828	
Jun-98	547.08	119.50	574	
Jul-98	607.13	111.60	608	
Aug-98	705.26	189.20	690	
Sep-98	667.56	327.80	659	
Oct-98	891.67	557.70	881	
Nov-98	847.85	792.30	864	
Dec-98	981.34	1051.80	927	
Jan-99	1435.13	1183.10	1,375	
Feb-99	997.18	976.40	903	
Mar-99	878.46	734.00	912	
Apr-99	933.28	508.80	923	
May-99	735.24	391.90	689	
Jun-99	592.75	153.90	597	
Jul-99	714.33	108.60	717	
Aug-99	570.63	145.70	584	
Sep-99	733.56	311.20	736	
Oct-99	848.54	499.80	876	
Nov-99	918.66	792.50	935	
Dec-99	943.63	844.00	1,027	
Jan-00	1393.34	1082.90	1,400	
Feb-00	907.58	735.20	973	
Mar-00	833.03	659.20	916	
Apr-00	818.24	515.60	803	
May-00	807.82	382.00	768	
Jun-00	726.05	172.50	718	
Jul-00	615.67	142.10	596	
Aug-00	625.23	219.90	589	
Sep-00	855.11	354.20	829	
Oct-00	808.86	539.20	810	
Nov-00	886.88	691.20	970	
Dec-00	1094.80	977.80	1,090	
Jan-01	975.84	722.70	1,220	
Feb-01	930.14	864.10	911	
Mar-01	1077.80	765.30	1,091	
Apr-01	775.11	506.80	766	
May-01	690.34	390.40	645	
Jun-01	697.52	167.30	693	
Jul-01	566.74	139.60	549	
Aug-01	566.46	139.60	584	
Sep-01	743.86	309.00	748	
Oct-01	726.03	573.40	705	
Nov-01	998.62	818.00	998	
Dec-01	885.26	1094.60	803	
Jan-02	1218.64	935.60	1,322	
Feb-02	1166.34	824.60	1,173	
Mar-02	942.27	921.10	852	
Apr-02	853.02	653.30	747	
May-02	811.69	361.60	786	
Jun-02	552.24	175.60	542	
Jul-02	580.09	130.90	568	
Aug-02	712.11	182.80	701	
Sep-02	638.11	314.40	639	
Oct-02	895.99	444.30	960	
Nov-02	783.30	582.60	938	
Dec-02	999.16	845.20	1,082	

Yukon Electrical Company Limited
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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1066.96	989.10	1,135	
Feb-03	944.33	756.60	996	
Mar-03	886.30	834.50	854	
Apr-03	896.61	514.30	883	
May-03	751.25	363.70	724	
Jun-03	555.79	192.80	535	
Jul-03	678.53	84.40	697	
Aug-03	595.25	180.60	586	
Sep-03	714.57	359.20	685	
Oct-03	849.90	466.70	899	
Nov-03	923.64	874.60	886	
Dec-03	1239.55	911.60	1,278	
Jan-04	1229.48	1257.90	1,120	
Feb-04	942.57	697.20	1,033	
Mar-04	928.19	753.50	949	
Apr-04	949.09	466.60	967	
May-04	638.54	272.50	671	
Jun-04	552.23	83.70	603	
Jul-04	655.59	74.20	681	
Aug-04	501.23	101.70	544	
Sep-04	788.19	367.50	754	
Oct-04	803.27	540.50	804	
Nov-04	860.77	719.80	925	
Dec-04	950.08	899.50	997	
Jan-05	1479.20	1165.80	1,431	
Feb-05	1034.01	795.20	1,060	
Mar-05	842.04	613.70	956	
Apr-05	955.29	453.30	982	
May-05	665.59	256.60	709	
Jun-05	684.41	154.40	689	
Jul-05	550.42	132.60	537	
Aug-05	592.88	150.80	603	
Sep-05	760.75	299.30	771	
Oct-05	774.90	534.60	779	
Nov-05	949.64	762.60	986	
Dec-05	919.10	794.40	1,035	
Jan-06	1402.18	1096.20	1,400	
Feb-06	980.19	821.30	989	
Mar-06	1262.81	906.30	1,183	
Apr-06	805.13	519.10	788	
May-06	688.68	346.90	672	
Jun-06	697.69	173.10	690	
Jul-06	640.63	118.40	637	
Aug-06	515.05	201.60	491	
Sep-06	742.30	295.70	755	
Oct-06	749.73	520.50	763	
Nov-06	1006.36	1162.20	778	
Dec-06	1107.96	824.30	1,204	
Jan-07	1554.07	912.00	1,673	
Feb-07	1054.99	998.80	946	
Mar-07	1221.11	954.20	1,109	
Apr-07	858.23	511.90	846	
May-07	656.87	322.10	657	
Jun-07	728.49	140.50	742	
Jul-07	590.23	102.30	597	
Aug-07	647.66	154.20	655	
Sep-07	654.75	308.40	659	
Oct-07	762.75	543.70	761	
Nov-07	1083.25	724.60	1,144	
Dec-07	918.94	1069.50	853	

Yukon Electrical Company Limited
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Carmacks Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1321.82	1113.80	1,308	
Feb-08	1748.89	954.60	1,669	
Mar-08	1140.23	734.70	1,174	
Apr-08	873.47	517.30	857	
May-08	829.73	307.90	839	
Jun-08	709.60	225.60	667	
Jul-08	522.26	173.40	482	
Aug-08	686.98	187.70	673	
Sep-08	753.10	318.70	751	
Oct-08	824.86	563.00	810	
Nov-08	1161.51	782.50	1,184	
Dec-08	1092.15	1186.20	949	
Jan-09	1569.02	1137.90	1,539	
Feb-09	1236.09	955.40	1,156	
Mar-09	1113.31	868.50	1,058	
Apr-09	996.41	515.20	982	
May-09	612.07	331.20	606	
Jun-09	571.72	144.10	583	
Jul-09	666.52	62.50	700	
Aug-09	598.19	158.30	603	
Sep-09	822.17	306.10	828	
Oct-09	812.98	541.80	813	
Nov-09	1007.46	781.50	1,031	
Dec-09	1085.22	943.40	1,103	
Jan-10	1623.07	991.10	1,690	
Feb-10	1029.40	679.20	1,132	
Mar-10	1034.68	656.00	1,120	
Apr-10	1023.38	461.20	1,044	
May-10	800.29	292.00	820	
Jun-10	565.81	171.90	558	
Jul-10	716.77	117.30	714	
Aug-10	673.16	146.20	686	
Sep-10	737.70	332.40	726	
Oct-10	867.23	520.40	881	
Nov-10	964.21	717.60	1,030	
Dec-10	1074.83	1162.50	947	11350.25
Jan-11	1619.00	1010.20	1,673	
Feb-11	1314.80	905.60	1,268	
Mar-11	1226.65	901.70	1,150	
Apr-11	914.05	511.20	902	
May-11	879.91	296.20	897	
Jun-11	597.78	161.00	598	
Jul-11	678.05	127.80	668	
Aug-11	693.54	217.90	659	
Sep-11	842.89	328.50	834	
Nov-11	835.82	513.30	854	
Nov-11	1102.99	936.25	1,024	
Dec-11	1062.36	775.10	1,191	11718.47
Jan-12	1703.03	1118.10	1,686	
Feb-12	1190.91	707.50	1,275	
Mar-12	1449.90	756.20	1,469	
Apr-12	690.39	450.60	718	
May-12	804.25	350.80	785	
Jun-12	756.31	200.00	730	
Jul-12	563.98	140.10	546	
Aug-12	758.98	157.90	764	
Sep-12	658.70	287.15	677	
Oct-12	801.33	631.40	742	
Nov-12	1382.24	969.60	1,281	
Dec-12	1290.39	1196.80	1,140	11814.86
2013-F				11,627.9
2014-F				11,627.9
2015-F				11,627.9

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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	795.40	1165.70	772	
Feb-98	784.90	719.10	822	
Mar-98	698.47	756.60	708	
Apr-98	607.38	458.60	619	
May-98	582.92	270.60	600	
Jun-98	472.72	119.50	486	
Jul-98	428.20	111.60	429	
Aug-98	436.56	189.20	429	
Sep-98	459.85	327.80	456	
Oct-98	499.13	557.70	494	
Nov-98	571.22	792.30	579	
Dec-98	584.94	1051.80	558	
Jan-99	838.31	1183.10	809	
Feb-99	727.77	976.40	682	
Mar-99	692.78	734.00	709	
Apr-99	606.91	508.80	602	
May-99	609.42	391.90	587	
Jun-99	501.14	153.90	503	
Jul-99	488.61	108.60	490	
Aug-99	412.25	145.70	419	
Sep-99	434.53	311.20	436	
Oct-99	540.51	499.80	554	
Nov-99	526.58	792.50	535	
Dec-99	790.71	844.00	831	
Jan-00	557.88	1082.90	561	
Feb-00	695.40	735.20	728	
Mar-00	576.79	659.20	618	
Apr-00	587.76	515.60	580	
May-00	525.67	382.00	506	
Jun-00	488.19	172.50	484	
Jul-00	448.25	142.10	439	
Aug-00	391.01	219.90	374	
Sep-00	500.13	354.20	488	
Oct-00	455.07	539.20	456	
Nov-00	503.14	691.20	544	
Dec-00	630.92	977.80	628	
Jan-01	635.82	722.70	756	
Feb-01	556.01	864.10	546	
Mar-01	674.24	765.30	681	
Apr-01	531.79	506.80	527	
May-01	511.07	390.40	489	
Jun-01	505.68	167.30	504	
Jul-01	412.26	139.60	404	
Aug-01	427.92	139.60	436	
Sep-01	409.71	309.00	412	
Oct-01	447.84	573.40	437	
Nov-01	539.82	818.00	539	
Dec-01	612.12	1094.60	572	
Jan-02	817.55	935.60	868	
Feb-02	635.92	824.60	639	
Mar-02	642.29	921.10	598	
Apr-02	651.11	653.30	599	
May-02	568.31	361.60	555	
Jun-02	462.46	175.60	458	
Jul-02	433.54	130.90	428	
Aug-02	445.58	182.80	440	
Sep-02	445.79	314.40	446	
Oct-02	473.63	444.30	505	
Nov-02	566.51	582.60	642	
Dec-02	552.02	845.20	592	

Yukon Electrical Company Limited
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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	744.25	989.10	778	
Feb-03	625.18	756.60	650	
Mar-03	609.25	834.50	593	
Apr-03	612.14	514.30	605	
May-03	559.97	363.70	546	
Jun-03	482.03	192.80	472	
Jul-03	472.76	84.40	482	
Aug-03	421.92	180.60	417	
Sep-03	459.71	359.20	445	
Oct-03	437.42	466.70	462	
Nov-03	584.07	874.60	565	
Dec-03	662.44	911.60	681	
Jan-04	795.06	1257.90	741	
Feb-04	716.36	697.20	761	
Mar-04	592.85	753.50	603	
Apr-04	589.84	466.60	598	
May-04	569.15	272.50	585	
Jun-04	439.01	83.70	464	
Jul-04	486.09	74.20	499	
Aug-04	395.12	101.70	416	
Sep-04	394.18	367.50	377	
Oct-04	488.31	540.50	488	
Nov-04	570.81	719.80	602	
Dec-04	637.87	899.50	661	
Jan-05	859.85	1165.80	836	
Feb-05	760.43	795.20	773	
Mar-05	642.22	613.70	698	
Apr-05	604.27	453.30	617	
May-05	506.22	256.60	527	
Jun-05	432.67	154.40	435	
Jul-05	450.86	132.60	445	
Aug-05	398.24	150.80	403	
Sep-05	469.63	299.30	475	
Oct-05	524.28	534.60	526	
Nov-05	557.58	762.60	575	
Dec-05	655.29	794.40	712	
Jan-06	841.77	1096.20	841	
Feb-06	737.13	821.30	741	
Mar-06	649.47	906.30	610	
Apr-06	691.39	519.10	683	
May-06	517.81	346.90	510	
Jun-06	590.90	173.10	587	
Jul-06	442.84	118.40	441	
Aug-06	462.30	201.60	451	
Sep-06	480.25	295.70	487	
Oct-06	496.77	520.50	503	
Nov-06	612.28	1162.20	500	
Dec-06	811.32	824.30	858	
Jan-07	830.63	912.00	889	
Feb-07	810.42	998.80	757	
Mar-07	791.75	954.20	737	
Apr-07	732.13	511.90	726	
May-07	554.95	322.10	555	
Jun-07	528.51	140.50	535	
Jul-07	458.69	102.30	462	
Aug-07	464.97	154.20	469	
Sep-07	451.01	308.40	453	
Oct-07	499.49	543.70	499	
Nov-07	229.05	724.60	259	
Dec-07	679.62	1069.50	647	

Yukon Electrical Company Limited
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Carcross Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	824.10	1113.80	817	
Feb-08	961.03	954.60	922	
Mar-08	726.66	734.70	743	
Apr-08	687.44	517.30	680	
May-08	614.67	307.90	619	
Jun-08	493.04	225.60	472	
Jul-08	456.88	173.40	437	
Aug-08	506.62	187.70	500	
Sep-08	453.32	318.70	452	
Oct-08	496.10	563.00	489	
Nov-08	623.30	782.50	634	
Dec-08	724.74	1186.20	655	
Jan-09	909.35	1137.90	895	
Feb-09	893.36	955.40	854	
Mar-09	825.31	868.50	798	
Apr-09	763.93	515.20	757	
May-09	696.17	331.20	693	
Jun-09	516.90	144.10	522	
Jul-09	497.49	62.50	514	
Aug-09	440.61	158.30	443	
Sep-09	473.82	306.10	477	
Oct-09	560.75	541.80	561	
Nov-09	617.21	781.50	629	
Dec-09	746.27	943.40	755	
Jan-10	951.15	991.10	984	
Feb-10	924.83	679.20	975	
Mar-10	740.59	656.00	782	
Apr-10	675.83	461.20	686	
May-10	649.67	292.00	659	
Jun-10	530.25	171.90	527	
Jul-10	481.28	117.30	480	
Aug-10	459.19	146.20	466	
Sep-10	454.07	332.40	449	
Oct-10	576.27	520.40	583	
Nov-10	632.62	717.60	665	
Dec-10	691.97	1162.50	630	7885.06
Jan-11	1038.06	1010.20	1,065	
Feb-11	873.67	905.60	851	
Mar-11	930.27	901.70	893	
Apr-11	796.07	511.20	790	
May-11	587.24	296.20	596	
Jun-11	560.33	161.00	560	
Jul-11	456.89	127.80	452	
Aug-11	438.61	217.90	422	
Sep-11	516.96	328.50	513	
Nov-11	531.54	513.30	541	
Nov-11	615.93	936.25	577	
Dec-11	839.15	775.10	902	8160.56
Jan-12	851.88	1118.10	844	
Feb-12	1019.77	707.50	1,061	
Mar-12	711.70	756.20	721	
Apr-12	684.68	450.60	698	
May-12	622.42	350.80	613	
Jun-12	543.45	200.00	531	
Jul-12	484.51	140.10	476	
Aug-12	511.31	157.90	514	
Sep-12	519.75	287.15	529	
Oct-12	520.94	631.40	492	
Nov-12	704.44	969.60	655	
Dec-12	819.40	1196.80	746	7878.97
2013-F				7,974.9
2014-F				7,974.9
2015-F				7,974.9

Yukon Electrical Company Limited
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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	983.84	1165.70	961	
Feb-98	757.50	719.10	794	
Mar-98	736.82	756.60	746	
Apr-98	667.46	458.60	678	
May-98	640.89	270.60	657	
Jun-98	570.83	119.50	584	
Jul-98	589.06	111.60	590	
Aug-98	505.35	189.20	498	
Sep-98	599.34	327.80	595	
Oct-98	659.23	557.70	654	
Nov-98	688.74	792.30	696	
Dec-98	705.63	1051.80	680	
Jan-99	1022.46	1183.10	994	
Feb-99	836.84	976.40	792	
Mar-99	758.68	734.00	775	
Apr-99	734.47	508.80	730	
May-99	605.20	391.90	583	
Jun-99	616.08	153.90	618	
Jul-99	589.39	108.60	591	
Aug-99	538.63	145.70	545	
Sep-99	588.89	311.20	590	
Oct-99	650.77	499.80	664	
Nov-99	711.91	792.50	720	
Dec-99	771.21	844.00	811	
Jan-00	919.17	1082.90	922	
Feb-00	767.81	735.20	799	
Mar-00	696.01	659.20	736	
Apr-00	653.56	515.60	646	
May-00	647.12	382.00	628	
Jun-00	633.92	172.50	630	
Jul-00	589.23	142.10	580	
Aug-00	565.57	219.90	549	
Sep-00	624.94	354.20	613	
Oct-00	645.35	539.20	646	
Nov-00	694.52	691.20	734	
Dec-00	704.97	977.80	702	
Jan-01	947.85	722.70	1,064	
Feb-01	740.58	864.10	731	
Mar-01	687.40	765.30	694	
Apr-01	631.85	506.80	628	
May-01	667.55	390.40	646	
Jun-01	650.33	167.30	648	
Jul-01	567.84	139.60	559	
Aug-01	570.31	139.60	579	
Sep-01	569.35	309.00	571	
Oct-01	632.74	573.40	623	
Nov-01	719.41	818.00	719	
Dec-01	848.28	1094.60	809	
Jan-02	965.83	935.60	1,015	
Feb-02	752.27	824.60	755	
Mar-02	737.50	921.10	695	
Apr-02	771.65	653.30	721	
May-02	629.03	361.60	617	
Jun-02	599.90	175.60	595	
Jul-02	567.28	130.90	562	
Aug-02	566.34	182.80	561	
Sep-02	599.66	314.40	600	
Oct-02	638.58	444.30	669	
Nov-02	776.11	582.60	850	
Dec-02	624.76	845.20	664	

Yukon Electrical Company Limited
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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	924.87	989.10	957	
Feb-03	708.42	756.60	733	
Mar-03	661.09	834.50	646	
Apr-03	649.40	514.30	643	
May-03	595.58	363.70	582	
Jun-03	585.92	192.80	576	
Jul-03	545.20	84.40	554	
Aug-03	514.74	180.60	510	
Sep-03	564.92	359.20	551	
Oct-03	546.52	466.70	570	
Nov-03	668.22	874.60	650	
Dec-03	772.74	911.60	791	
Jan-04	872.87	1257.90	821	
Feb-04	767.27	697.20	810	
Mar-04	635.49	753.50	645	
Apr-04	672.11	466.60	680	
May-04	550.50	272.50	566	
Jun-04	506.18	83.70	530	
Jul-04	581.92	74.20	594	
Aug-04	489.54	101.70	510	
Sep-04	573.71	367.50	557	
Oct-04	567.32	540.50	568	
Nov-04	649.55	719.80	680	
Dec-04	765.21	899.50	787	
Jan-05	865.66	1165.80	843	
Feb-05	799.12	795.20	811	
Mar-05	619.53	613.70	673	
Apr-05	686.53	453.30	699	
May-05	568.24	256.60	589	
Jun-05	531.01	154.40	533	
Jul-05	561.76	132.60	556	
Aug-05	495.10	150.80	500	
Sep-05	646.17	299.30	651	
Oct-05	572.83	534.60	575	
Nov-05	687.06	762.60	704	
Dec-05	705.12	794.40	760	
Jan-06	876.57	1096.20	875	
Feb-06	787.19	821.30	791	
Mar-06	737.76	906.30	700	
Apr-06	634.57	519.10	626	
May-06	620.22	346.90	612	
Jun-06	565.22	173.10	561	
Jul-06	599.03	118.40	597	
Aug-06	530.52	201.60	519	
Sep-06	580.60	295.70	587	
Oct-06	513.53	520.50	520	
Nov-06	757.45	1162.20	649	
Dec-06	659.12	824.30	705	
Jan-07	1088.17	912.00	1,145	
Feb-07	791.83	998.80	740	
Mar-07	795.39	954.20	742	
Apr-07	713.40	511.90	707	
May-07	540.96	322.10	541	
Jun-07	629.17	140.50	636	
Jul-07	478.58	102.30	482	
Aug-07	493.46	154.20	497	
Sep-07	611.35	308.40	613	
Oct-07	554.34	543.70	554	
Nov-07	689.91	724.60	719	
Dec-07	745.97	1069.50	715	

Yukon Electrical Company Limited
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Haines Junction Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	912.87	1113.80	906	
Feb-08	846.73	954.60	809	
Mar-08	843.51	734.70	859	
Apr-08	670.54	517.30	663	
May-08	563.76	307.90	568	
Jun-08	521.70	225.60	501	
Jul-08	603.53	173.40	585	
Aug-08	527.07	187.70	520	
Sep-08	586.83	318.70	586	
Oct-08	519.77	563.00	513	
Nov-08	668.89	782.50	680	
Dec-08	757.37	1186.20	689	
Jan-09	1021.75	1137.90	1,007	
Feb-09	730.55	955.40	693	
Mar-09	789.49	868.50	763	
Apr-09	640.24	515.20	633	
May-09	683.39	331.20	681	
Jun-09	548.03	144.10	553	
Jul-09	535.04	62.50	551	
Aug-09	507.97	158.30	510	
Sep-09	532.13	306.10	535	
Oct-09	577.93	541.80	578	
Nov-09	738.06	781.50	749	
Dec-09	700.84	943.40	709	
Jan-10	961.89	991.10	994	
Feb-10	714.53	679.20	763	
Mar-10	712.94	656.00	754	
Apr-10	609.79	461.20	620	
May-10	615.98	292.00	625	
Jun-10	578.19	171.90	575	
Jul-10	518.10	117.30	517	
Aug-10	488.66	146.20	495	
Sep-10	549.61	332.40	544	
Oct-10	572.26	520.40	579	
Nov-10	681.19	717.60	712	
Dec-10	710.29	1162.50	650	7827.21
Jan-11	999.60	1010.20	1,025	
Feb-11	753.69	905.60	731	
Mar-11	773.04	901.70	736	
Apr-11	659.04	511.20	653	
May-11	665.59	296.20	674	
Jun-11	541.03	161.00	541	
Jul-11	535.52	127.80	531	
Aug-11	466.57	217.90	450	
Sep-11	516.28	328.50	512	
Nov-11	600.63	513.30	609	
Nov-11	681.86	936.25	644	
Dec-11	735.64	775.10	797	7905.05
Jan-12	928.36	1118.10	920	
Feb-12	821.58	707.50	861	
Mar-12	730.15	756.20	739	
Apr-12	655.88	450.60	669	
May-12	548.21	350.80	539	
Jun-12	599.23	200.00	587	
Jul-12	537.57	140.10	529	
Aug-12	429.88	157.90	432	
Sep-12	560.48	287.15	569	
Oct-12	571.07	631.40	543	
Nov-12	670.46	969.60	623	
Dec-12	905.15	1196.80	834	7846.23
2013-F				7,859.5
2014-F				7,859.5
2015-F				7,859.5

Yukon Electrical Company Limited
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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	814.83	1165.70	793	
Feb-98	583.38	719.10	618	
Mar-98	544.14	756.60	553	
Apr-98	578.51	458.60	589	
May-98	446.48	270.60	462	
Jun-98	410.56	119.50	423	
Jul-98	499.27	111.60	500	
Aug-98	443.49	189.20	437	
Sep-98	458.11	327.80	454	
Oct-98	539.94	557.70	535	
Nov-98	553.91	792.30	561	
Dec-98	624.43	1051.80	600	
Jan-99	836.66	1183.10	810	
Feb-99	603.72	976.40	562	
Mar-99	658.99	734.00	674	
Apr-99	586.70	508.80	582	
May-99	457.76	391.90	437	
Jun-99	510.14	153.90	512	
Jul-99	508.78	108.60	510	
Aug-99	411.15	145.70	417	
Sep-99	463.34	311.20	465	
Oct-99	523.66	499.80	536	
Nov-99	511.67	792.50	519	
Dec-99	548.25	844.00	585	
Jan-00	836.92	1082.90	840	
Feb-00	564.40	735.20	594	
Mar-00	491.79	659.20	529	
Apr-00	545.27	515.60	539	
May-00	474.06	382.00	456	
Jun-00	513.85	172.50	510	
Jul-00	418.80	142.10	410	
Aug-00	422.89	219.90	407	
Sep-00	546.71	354.20	535	
Oct-00	487.08	539.20	488	
Nov-00	589.99	691.20	627	
Dec-00	565.52	977.80	563	
Jan-01	637.66	722.70	747	
Feb-01	570.31	864.10	562	
Mar-01	629.10	765.30	635	
Apr-01	537.20	506.80	533	
May-01	475.35	390.40	455	
Jun-01	515.46	167.30	514	
Jul-01	452.81	139.60	445	
Aug-01	423.69	139.60	431	
Sep-01	490.14	309.00	492	
Oct-01	473.38	573.40	464	
Nov-01	581.48	818.00	581	
Dec-01	640.26	1094.60	603	
Jan-02	639.45	935.60	686	
Feb-02	719.93	824.60	723	
Mar-02	537.74	921.10	498	
Apr-02	538.57	653.30	491	
May-02	583.89	361.60	572	
Jun-02	420.09	175.60	416	
Jul-02	427.53	130.90	422	
Aug-02	485.55	182.80	481	
Sep-02	415.97	314.40	416	
Oct-02	533.02	444.30	562	
Nov-02	528.75	582.60	598	
Dec-02	570.09	845.20	607	

Yukon Electrical Company Limited
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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	721.32	989.10	752	
Feb-03	546.55	756.60	570	
Mar-03	531.06	834.50	516	
Apr-03	434.00	514.30	428	
May-03	564.98	363.70	553	
Jun-03	427.05	192.80	418	
Jul-03	479.75	84.40	488	
Aug-03	427.74	180.60	423	
Sep-03	463.66	359.20	451	
Oct-03	515.88	466.70	538	
Nov-03	535.51	874.60	518	
Dec-03	622.70	911.60	640	
Jan-04	831.65	1257.90	783	
Feb-04	643.18	697.20	684	
Mar-04	439.96	753.50	449	
Apr-04	574.90	466.60	583	
May-04	432.44	272.50	447	
Jun-04	450.06	83.70	473	
Jul-04	510.64	74.20	522	
Aug-04	405.29	101.70	424	
Sep-04	531.29	367.50	516	
Oct-04	503.38	540.50	504	
Nov-04	529.19	719.80	558	
Dec-04	575.73	899.50	597	
Jan-05	925.27	1165.80	904	
Feb-05	614.63	795.20	626	
Mar-05	534.56	613.70	585	
Apr-05	545.34	453.30	557	
May-05	480.04	256.60	499	
Jun-05	416.22	154.40	418	
Jul-05	466.39	132.60	461	
Aug-05	430.48	150.80	435	
Sep-05	522.47	299.30	527	
Oct-05	458.91	534.60	461	
Nov-05	552.59	762.60	569	
Dec-05	576.80	794.40	629	
Jan-06	815.85	1096.20	815	
Feb-06	599.60	821.30	603	
Mar-06	738.67	906.30	703	
Apr-06	511.35	519.10	504	
May-06	501.90	346.90	495	
Jun-06	523.50	173.10	520	
Jul-06	441.61	118.40	440	
Aug-06	419.21	201.60	409	
Sep-06	540.22	295.70	546	
Oct-06	477.26	520.50	483	
Nov-06	546.24	1162.20	444	
Dec-06	681.70	824.30	725	
Jan-07	821.97	912.00	875	
Feb-07	590.96	998.80	542	
Mar-07	736.70	954.20	687	
Apr-07	529.70	511.90	524	
May-07	616.82	322.10	617	
Jun-07	521.68	140.50	528	
Jul-07	443.72	102.30	447	
Aug-07	465.45	154.20	469	
Sep-07	500.47	308.40	502	
Oct-07	549.57	543.70	549	
Nov-07	645.22	724.60	673	
Dec-07	589.02	1069.50	560	

Yukon Electrical Company Limited
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Teslin Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	883.32	1113.80	877	
Feb-08	943.04	954.60	908	
Mar-08	541.12	734.70	556	
Apr-08	545.58	517.30	538	
May-08	563.22	307.90	567	
Jun-08	417.21	225.60	398	
Jul-08	424.77	173.40	407	
Aug-08	530.76	187.70	524	
Sep-08	477.15	318.70	476	
Oct-08	601.14	563.00	595	
Nov-08	565.56	782.50	576	
Dec-08	641.23	1186.20	577	
Jan-09	1032.69	1137.90	1,019	
Feb-09	915.59	955.40	880	
Mar-09	504.65	868.50	480	
Apr-09	543.06	515.20	537	
May-09	603.03	331.20	600	
Jun-09	418.40	144.10	423	
Jul-09	512.97	62.50	528	
Aug-09	427.44	158.30	430	
Sep-09	440.10	306.10	443	
Oct-09	561.57	541.80	561	
Nov-09	569.68	781.50	580	
Dec-09	659.17	943.40	667	
Jan-10	891.22	991.10	921	
Feb-10	641.06	679.20	687	
Mar-10	608.19	656.00	646	
Apr-10	650.73	461.20	660	
May-10	491.31	292.00	500	
Jun-10	460.20	171.90	457	
Jul-10	531.56	117.30	530	
Aug-10	387.03	146.20	393	
Sep-10	526.23	332.40	521	
Oct-10	544.32	520.40	550	
Nov-10	617.76	717.60	647	
Dec-10	785.33	1162.50	728	7242.12
Jan-11	858.50	1010.20	883	
Feb-11	654.02	905.60	633	
Mar-11	823.05	901.70	789	
Apr-11	554.51	511.20	549	
May-11	616.54	296.20	624	
Jun-11	456.23	161.00	456	
Jul-11	510.58	127.80	506	
Aug-11	434.33	217.90	419	
Sep-11	532.19	328.50	528	
Nov-11	532.41	513.30	541	
Nov-11	599.18	936.25	564	
Dec-11	711.46	775.10	769	7260.93
Jan-12	956.09	1118.10	949	
Feb-12	675.67	707.50	713	
Mar-12	733.04	756.20	742	
Apr-12	577.68	450.60	590	
May-12	510.64	350.80	502	
Jun-12	501.48	200.00	490	
Jul-12	424.34	140.10	416	
Aug-12	390.29	157.90	393	
Sep-12	504.10	287.15	512	
Oct-12	496.11	631.40	469	
Nov-12	744.48	969.60	699	
Dec-12	776.29	1196.80	709	7184.92
2013-F				7,229.3
2014-F				7,229.3
2015-F				7,229.3

Yukon Electrical Company Limited
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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1058.61	1165.70	1,027	
Feb-98	802.93	719.10	852	
Mar-98	782.98	756.60	795	
Apr-98	635.51	458.60	650	
May-98	527.58	270.60	549	
Jun-98	502.43	119.50	520	
Jul-98	553.31	111.60	554	
Aug-98	450.98	189.20	441	
Sep-98	560.04	327.80	555	
Oct-98	567.35	557.70	560	
Nov-98	592.30	792.30	603	
Dec-98	841.44	1051.80	807	
Jan-99	955.97	1183.10	917	
Feb-99	798.82	976.40	738	
Mar-99	706.66	734.00	728	
Apr-99	703.14	508.80	696	
May-99	575.71	391.90	546	
Jun-99	504.68	153.90	508	
Jul-99	581.67	108.60	584	
Aug-99	471.87	145.70	480	
Sep-99	470.53	311.20	472	
Oct-99	640.23	499.80	658	
Nov-99	646.77	792.50	657	
Dec-99	723.70	844.00	777	
Jan-00	962.75	1082.90	967	
Feb-00	777.86	735.20	820	
Mar-00	678.69	659.20	732	
Apr-00	787.68	515.60	778	
May-00	514.79	382.00	489	
Jun-00	649.68	172.50	645	
Jul-00	466.75	142.10	454	
Aug-00	475.15	219.90	452	
Sep-00	628.05	354.20	611	
Oct-00	600.16	539.20	601	
Nov-00	615.52	691.20	669	
Dec-00	854.24	977.80	851	
Jan-01	823.92	722.70	982	
Feb-01	680.11	864.10	667	
Mar-01	846.67	765.30	855	
Apr-01	594.39	506.80	589	
May-01	579.91	390.40	551	
Jun-01	560.11	167.30	557	
Jul-01	467.58	139.60	456	
Aug-01	431.08	139.60	442	
Sep-01	510.75	309.00	513	
Oct-01	560.69	573.40	547	
Nov-01	734.63	818.00	734	
Dec-01	730.50	1094.60	677	
Jan-02	822.54	935.60	889	
Feb-02	853.68	824.60	858	
Mar-02	656.59	921.10	599	
Apr-02	665.33	653.30	597	
May-02	614.79	361.60	598	
Jun-02	447.73	175.60	441	
Jul-02	427.71	130.90	420	
Aug-02	511.99	182.80	505	
Sep-02	414.68	314.40	415	
Oct-02	493.82	444.30	535	
Nov-02	662.60	582.60	762	
Dec-02	621.65	845.20	675	

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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	845.05	989.10	889	
Feb-03	717.88	756.60	751	
Mar-03	629.68	834.50	609	
Apr-03	549.62	514.30	541	
May-03	560.55	363.70	543	
Jun-03	430.80	192.80	417	
Jul-03	456.65	84.40	469	
Aug-03	386.93	180.60	381	
Sep-03	402.75	359.20	384	
Oct-03	473.35	466.70	505	
Nov-03	675.36	874.60	651	
Dec-03	727.12	911.60	752	
Jan-04	883.78	1257.90	813	
Feb-04	769.43	697.20	828	
Mar-04	640.26	753.50	654	
Apr-04	685.20	466.60	696	
May-04	498.86	272.50	520	
Jun-04	453.36	83.70	486	
Jul-04	486.84	74.20	503	
Aug-04	414.96	101.70	442	
Sep-04	538.59	367.50	516	
Oct-04	500.05	540.50	500	
Nov-04	567.59	719.80	609	
Dec-04	714.77	899.50	745	
Jan-05	999.04	1165.80	968	
Feb-05	829.08	795.20	846	
Mar-05	632.61	613.70	706	
Apr-05	687.74	453.30	705	
May-05	513.18	256.60	541	
Jun-05	435.44	154.40	438	
Jul-05	489.22	132.60	481	
Aug-05	456.94	150.80	463	
Sep-05	583.92	299.30	591	
Oct-05	496.19	534.60	499	
Nov-05	593.04	762.60	616	
Dec-05	736.25	794.40	811	
Jan-06	960.57	1096.20	959	
Feb-06	800.58	821.30	806	
Mar-06	697.45	906.30	646	
Apr-06	729.55	519.10	718	
May-06	556.74	346.90	546	
Jun-06	532.97	173.10	528	
Jul-06	425.93	118.40	424	
Aug-06	393.88	201.60	379	
Sep-06	522.31	295.70	531	
Oct-06	524.67	520.50	533	
Nov-06	688.63	1162.20	541	
Dec-06	891.59	824.30	954	
Jan-07	778.56	912.00	855	
Feb-07	714.26	998.80	644	
Mar-07	962.61	954.20	891	
Apr-07	682.24	511.90	674	
May-07	505.16	322.10	505	
Jun-07	527.06	140.50	536	
Jul-07	421.53	102.30	426	
Aug-07	468.88	154.20	474	
Sep-07	445.35	308.40	448	
Oct-07	562.99	543.70	562	
Nov-07	732.80	724.60	772	
Dec-07	702.63	1069.50	660	

Yukon Electrical Company Limited
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Ross River Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	844.07	1113.80	835	
Feb-08	1085.47	954.60	1,034	
Mar-08	692.21	734.70	714	
Apr-08	608.14	517.30	598	
May-08	652.16	307.90	658	
Jun-08	494.57	225.60	467	
Jul-08	506.30	173.40	481	
Aug-08	527.41	187.70	518	
Sep-08	571.02	318.70	570	
Oct-08	557.13	563.00	548	
Nov-08	809.42	782.50	824	
Dec-08	766.96	1186.20	675	
Jan-09	1265.61	1137.90	1,246	
Feb-09	802.19	955.40	751	
Mar-09	805.56	868.50	770	
Apr-09	683.92	515.20	674	
May-09	677.89	331.20	674	
Jun-09	569.55	144.10	577	
Jul-09	595.67	62.50	617	
Aug-09	538.97	158.30	542	
Sep-09	432.36	306.10	436	
Oct-09	701.93	541.80	702	
Nov-09	620.17	781.50	635	
Dec-09	850.55	943.40	862	
Jan-10	1055.40	991.10	1,099	
Feb-10	770.51	679.20	837	
Mar-10	660.56	656.00	716	
Apr-10	749.98	461.20	764	
May-10	552.02	292.00	565	
Jun-10	526.57	171.90	522	
Jul-10	564.03	117.30	562	
Aug-10	480.88	146.20	489	
Sep-10	604.33	332.40	597	
Oct-10	586.26	520.40	595	
Nov-10	657.45	717.60	700	
Dec-10	957.38	1162.50	875	8319.79
Jan-11	1094.65	1010.20	1,130	
Feb-11	955.36	905.60	925	
Mar-11	955.04	901.70	905	
Apr-11	885.86	511.20	878	
May-11	651.54	296.20	663	
Jun-11	541.38	161.00	541	
Jul-11	561.73	127.80	555	
Aug-11	498.85	217.90	477	
Sep-11	623.09	328.50	617	
Nov-11	596.88	513.30	609	
Nov-11	642.83	936.25	592	
Dec-11	965.29	775.10	1,048	8940.71
Jan-12	1092.16	1118.10	1,081	
Feb-12	980.46	707.50	1,035	
Mar-12	973.30	756.20	986	
Apr-12	710.75	450.60	729	
May-12	586.09	350.80	574	
Jun-12	641.20	200.00	624	
Jul-12	503.49	140.10	492	
Aug-12	525.95	157.90	529	
Sep-12	506.90	287.15	519	
Oct-12	559.65	631.40	521	
Nov-12	904.69	969.60	840	
Dec-12	984.57	1196.80	888	8817.46
2013-F				8,692.7
2014-F				8,692.7
2015-F				8,692.7

Yukon Electrical Company Limited
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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1086.53	1165.70	1,054	
Feb-98	894.52	719.10	946	
Mar-98	698.46	756.60	711	
Apr-98	734.53	458.60	750	
May-98	712.52	270.60	736	
Jun-98	521.79	119.50	540	
Jul-98	523.55	111.60	524	
Aug-98	585.02	189.20	575	
Sep-98	613.51	327.80	608	
Oct-98	783.35	557.70	776	
Nov-98	715.70	792.30	727	
Dec-98	891.62	1051.80	855	
Jan-99	1202.83	1183.10	1,162	
Feb-99	867.89	976.40	804	
Mar-99	785.96	734.00	809	
Apr-99	874.25	508.80	867	
May-99	651.94	391.90	621	
Jun-99	572.35	153.90	575	
Jul-99	644.52	108.60	647	
Aug-99	563.70	145.70	573	
Sep-99	670.87	311.20	673	
Oct-99	854.54	499.80	873	
Nov-99	779.73	792.50	791	
Dec-99	833.26	844.00	890	
Jan-00	1247.38	1082.90	1,252	
Feb-00	838.80	735.20	883	
Mar-00	812.30	659.20	869	
Apr-00	899.88	515.60	890	
May-00	691.76	382.00	665	
Jun-00	714.63	172.50	709	
Jul-00	584.60	142.10	572	
Aug-00	613.12	219.90	589	
Sep-00	787.57	354.20	770	
Oct-00	748.53	539.20	749	
Nov-00	942.50	691.20	999	
Dec-00	703.96	977.80	700	
Jan-01	999.24	722.70	1,165	
Feb-01	825.88	864.10	813	
Mar-01	905.03	765.30	914	
Apr-01	691.19	506.80	685	
May-01	684.13	390.40	653	
Jun-01	647.41	167.30	644	
Jul-01	575.81	139.60	564	
Aug-01	501.88	139.60	514	
Sep-01	713.12	309.00	716	
Oct-01	673.23	573.40	659	
Nov-01	926.77	818.00	926	
Dec-01	859.92	1094.60	804	
Jan-02	1107.62	935.60	1,178	
Feb-02	1065.08	824.60	1,070	
Mar-02	774.38	921.10	713	
Apr-02	748.68	653.30	677	
May-02	768.50	361.60	751	
Jun-02	532.39	175.60	526	
Jul-02	550.67	130.90	543	
Aug-02	688.70	182.80	681	
Sep-02	661.12	314.40	661	
Oct-02	692.18	444.30	736	
Nov-02	698.09	582.60	803	
Dec-02	867.76	845.20	924	

Yukon Electrical Company Limited
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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	871.39	989.10	918	
Feb-03	804.10	756.60	839	
Mar-03	769.27	834.50	747	
Apr-03	727.56	514.30	718	
May-03	770.30	363.70	752	
Jun-03	580.73	192.80	566	
Jul-03	643.85	84.40	657	
Aug-03	595.08	180.60	588	
Sep-03	655.14	359.20	635	
Oct-03	783.86	466.70	817	
Nov-03	782.44	874.60	757	
Dec-03	1061.74	911.60	1,088	
Jan-04	1003.81	1257.90	929	
Feb-04	822.85	697.20	885	
Mar-04	780.66	753.50	795	
Apr-04	883.00	466.60	895	
May-04	642.85	272.50	665	
Jun-04	674.85	83.70	710	
Jul-04	592.92	74.20	610	
Aug-04	558.72	101.70	588	
Sep-04	653.99	367.50	631	
Oct-04	809.17	540.50	809	
Nov-04	861.12	719.80	905	
Dec-04	724.34	899.50	756	
Jan-05	1183.78	1165.80	1,151	
Feb-05	909.36	795.20	927	
Mar-05	731.02	613.70	808	
Apr-05	848.22	453.30	866	
May-05	638.99	256.60	668	
Jun-05	703.20	154.40	706	
Jul-05	533.44	132.60	525	
Aug-05	593.29	150.80	600	
Sep-05	749.13	299.30	756	
Oct-05	657.93	534.60	661	
Nov-05	769.26	762.60	794	
Dec-05	817.06	794.40	896	
Jan-06	1146.78	1096.20	1,145	
Feb-06	759.28	821.30	765	
Mar-06	966.29	906.30	912	
Apr-06	678.30	519.10	667	
May-06	665.18	346.90	654	
Jun-06	667.39	173.10	662	
Jul-06	558.64	118.40	556	
Aug-06	509.76	201.60	494	
Sep-06	730.68	295.70	739	
Oct-06	681.16	520.50	690	
Nov-06	848.43	1162.20	693	
Dec-06	915.06	824.30	980	
Jan-07	1168.96	912.00	1,250	
Feb-07	871.57	998.80	798	
Mar-07	1033.18	954.20	957	
Apr-07	692.54	511.90	684	
May-07	721.82	322.10	722	
Jun-07	656.80	140.50	666	
Jul-07	450.58	102.30	455	
Aug-07	729.07	154.20	734	
Sep-07	579.48	308.40	583	
Oct-07	684.48	543.70	683	
Nov-07	929.33	724.60	971	
Dec-07	732.54	1069.50	688	

Yukon Electrical Company Limited
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Pelly Crossing Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1142.47	1113.80	1,133	
Feb-08	1286.97	954.60	1,233	
Mar-08	958.31	734.70	981	
Apr-08	575.54	517.30	565	
May-08	810.33	307.90	817	
Jun-08	608.33	225.60	579	
Jul-08	440.43	173.40	413	
Aug-08	623.13	187.70	613	
Sep-08	567.82	318.70	566	
Oct-08	735.62	563.00	726	
Nov-08	807.28	782.50	823	
Dec-08	884.48	1186.20	787	
Jan-09	1349.67	1137.90	1,329	
Feb-09	1030.29	955.40	976	
Mar-09	1005.63	868.50	968	
Apr-09	692.25	515.20	682	
May-09	715.75	331.20	712	
Jun-09	547.04	144.10	555	
Jul-09	605.96	62.50	629	
Aug-09	534.67	158.30	538	
Sep-09	619.24	306.10	623	
Oct-09	840.58	541.80	840	
Nov-09	863.76	781.50	880	
Dec-09	924.28	943.40	936	
Jan-10	972.81	991.10	1,018	
Feb-10	825.37	679.20	895	
Mar-10	777.19	656.00	835	
Apr-10	824.62	461.20	839	
May-10	680.58	292.00	694	
Jun-10	551.48	171.90	546	
Jul-10	751.59	117.30	750	
Aug-10	519.94	146.20	529	
Sep-10	692.34	332.40	685	
Oct-10	693.91	520.40	703	
Nov-10	773.77	717.60	818	
Dec-10	836.17	1162.50	750	9062.61
Jan-11	1250.81	1010.20	1,288	
Feb-11	924.10	905.60	892	
Mar-11	905.22	901.70	853	
Apr-11	759.94	511.20	752	
May-11	764.85	296.20	776	
Jun-11	544.81	161.00	545	
Jul-11	642.51	127.80	636	
Aug-11	593.52	217.90	570	
Sep-11	714.31	328.50	708	
Nov-11	677.94	513.30	690	
Nov-11	890.35	936.25	837	
Dec-11	942.47	775.10	1,030	9577.29
Jan-12	1316.41	1118.10	1,305	
Feb-12	897.93	707.50	955	
Mar-12	1081.45	756.20	1,094	
Apr-12	597.87	450.60	617	
May-12	702.24	350.80	689	
Jun-12	799.19	200.00	782	
Jul-12	444.11	140.10	432	
Aug-12	650.10	157.90	654	
Sep-12	633.41	287.15	646	
Oct-12	724.40	631.40	684	
Nov-12	1161.91	969.60	1,093	
Dec-12	1135.86	1196.80	1,034	9984.89
2013-F				9,541.6
2014-F				9,541.6
2015-F				9,541.6

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Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	874.55	1165.70	855	
Feb-98	636.30	719.10	668	
Mar-98	680.81	756.60	689	
Apr-98	495.37	458.60	505	
May-98	543.47	270.60	557	
Jun-98	480.21	119.50	491	
Jul-98	210.67	111.60	211	
Aug-98	585.17	189.20	579	
Sep-98	489.61	327.80	486	
Oct-98	562.92	557.70	558	
Nov-98	515.39	792.30	522	
Dec-98	631.39	1051.80	609	
Jan-99	758.98	1183.10	734	
Feb-99	605.30	976.40	567	
Mar-99	597.31	734.00	611	
Apr-99	685.87	508.80	682	
May-99	459.29	391.90	440	
Jun-99	441.67	153.90	444	
Jul-99	535.10	108.60	536	
Aug-99	448.78	145.70	454	
Sep-99	439.71	311.20	441	
Oct-99	647.73	499.80	659	
Nov-99	581.70	792.50	588	
Dec-99	648.90	844.00	683	
Jan-00	903.37	1082.90	906	
Feb-00	652.46	735.20	679	
Mar-00	772.30	659.20	807	
Apr-00	471.82	515.60	466	
May-00	572.87	382.00	557	
Jun-00	603.80	172.50	601	
Jul-00	426.62	142.10	419	
Aug-00	432.41	219.90	418	
Sep-00	466.62	354.20	456	
Oct-00	611.91	539.20	612	
Nov-00	504.54	691.20	539	
Dec-00	672.91	977.80	671	
Jan-01	719.83	722.70	821	
Feb-01	591.68	864.10	584	
Mar-01	657.71	765.30	663	
Apr-01	607.24	506.80	604	
May-01	573.66	390.40	555	
Jun-01	456.47	167.30	455	
Jul-01	434.01	139.60	427	
Aug-01	398.59	139.60	406	
Sep-01	494.61	309.00	496	
Oct-01	429.23	573.40	420	
Nov-01	551.22	818.00	551	
Dec-01	542.01	1094.60	508	
Jan-02	653.86	935.60	697	
Feb-02	715.86	824.60	719	
Mar-02	540.61	921.10	504	
Apr-02	525.12	653.30	482	
May-02	536.55	361.60	526	
Jun-02	393.60	175.60	390	
Jul-02	434.95	130.90	430	
Aug-02	508.20	182.80	504	
Sep-02	417.07	314.40	417	
Oct-02	461.60	444.30	488	
Nov-02	635.48	582.60	699	
Dec-02	557.29	845.20	591	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	783.92	989.10	812	
Feb-03	655.33	756.60	677	
Mar-03	621.21	834.50	608	
Apr-03	590.57	514.30	585	
May-03	558.87	363.70	548	
Jun-03	457.13	192.80	448	
Jul-03	504.68	84.40	512	
Aug-03	408.95	180.60	405	
Sep-03	463.75	359.20	452	
Oct-03	432.28	466.70	453	
Nov-03	528.04	874.60	512	
Dec-03	638.87	911.60	655	
Jan-04	792.39	1257.90	747	
Feb-04	655.38	697.20	693	
Mar-04	667.89	753.50	677	
Apr-04	590.63	466.60	598	
May-04	555.43	272.50	569	
Jun-04	477.73	83.70	499	
Jul-04	485.17	74.20	496	
Aug-04	444.82	101.70	462	
Sep-04	390.05	367.50	376	
Oct-04	546.44	540.50	547	
Nov-04	588.90	719.80	615	
Dec-04	624.32	899.50	643	
Jan-05	900.64	1165.80	881	
Feb-05	686.79	795.20	697	
Mar-05	690.73	613.70	737	
Apr-05	737.85	453.30	749	
May-05	537.04	256.60	555	
Jun-05	454.68	154.40	456	
Jul-05	499.65	132.60	494	
Aug-05	481.44	150.80	486	
Sep-05	468.61	299.30	473	
Oct-05	581.06	534.60	583	
Nov-05	555.41	762.60	570	
Dec-05	647.48	794.40	695	
Jan-06	856.21	1096.20	855	
Feb-06	730.66	821.30	734	
Mar-06	645.01	906.30	612	
Apr-06	720.45	519.10	713	
May-06	589.11	346.90	582	
Jun-06	512.44	173.10	509	
Jul-06	437.86	118.40	436	
Aug-06	422.35	201.60	413	
Sep-06	562.12	295.70	567	
Oct-06	463.28	520.50	469	
Nov-06	468.83	1162.20	375	
Dec-06	743.18	824.30	783	
Jan-07	755.01	912.00	804	
Feb-07	663.57	998.80	619	
Mar-07	762.87	954.20	717	
Apr-07	651.80	511.90	647	
May-07	509.32	322.10	509	
Jun-07	546.58	140.50	552	
Jul-07	441.92	102.30	445	
Aug-07	392.80	154.20	396	
Sep-07	529.69	308.40	532	
Oct-07	464.20	543.70	463	
Nov-07	646.91	724.60	672	
Dec-07	626.85	1069.50	600	

Yukon Electrical Company Limited
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Old Crow Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	695.27	1113.80	689	
Feb-08	795.35	954.60	763	
Mar-08	587.17	734.70	601	
Apr-08	571.63	517.30	565	
May-08	549.53	307.90	553	
Jun-08	559.91	225.60	542	
Jul-08	399.54	173.40	383	
Aug-08	533.24	187.70	527	
Sep-08	447.71	318.70	447	
Oct-08	409.45	563.00	403	
Nov-08	634.01	782.50	643	
Dec-08	560.56	1186.20	502	
Jan-09	860.77	1137.90	848	
Feb-09	643.45	955.40	611	
Mar-09	645.28	868.50	623	
Apr-09	648.59	515.20	643	
May-09	594.31	331.20	592	
Jun-09	494.44	144.10	499	
Jul-09	520.22	62.50	534	
Aug-09	407.68	158.30	410	
Sep-09	425.84	306.10	428	
Oct-09	592.41	541.80	592	
Nov-09	637.09	781.50	647	
Dec-09	586.46	943.40	594	
Jan-10	815.74	991.10	843	
Feb-10	685.26	679.20	728	
Mar-10	633.69	656.00	669	
Apr-10	750.63	461.20	759	
May-10	485.36	292.00	494	
Jun-10	441.99	171.90	439	
Jul-10	506.08	117.30	505	
Aug-10	413.70	146.20	419	
Sep-10	472.21	332.40	468	
Oct-10	596.04	520.40	602	
Nov-10	567.52	717.60	595	
Dec-10	637.92	1162.50	585	7104.80
Jan-11	1043.99	1010.20	1,066	
Feb-11	764.53	905.60	745	
Mar-11	684.51	901.70	653	
Apr-11	877.27	511.20	872	
May-11	686.25	296.20	693	
Jun-11	459.01	161.00	459	
Jul-11	548.97	127.80	545	
Aug-11	454.18	217.90	440	
Sep-11	523.52	328.50	520	
Nov-11	507.80	513.30	515	
Nov-11	573.69	936.25	541	
Dec-11	811.99	775.10	865	7915.38
Jan-12	787.32	1118.10	780	
Feb-12	730.70	707.50	765	
Mar-12	835.48	756.20	843	
Apr-12	661.65	450.60	673	
May-12	566.76	350.80	559	
Jun-12	588.77	200.00	578	
Jul-12	435.38	140.10	428	
Aug-12	586.84	157.90	589	
Sep-12	343.63	287.15	351	
Oct-12	499.01	631.40	474	
Nov-12	645.99	969.60	604	
Dec-12	785.18	1196.80	723	7369.77
2013-F				7,463.3
2014-F				7,463.3
2015-F				7,463.3

Yukon Electrical Company Limited
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Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	659.49	1165.70	643	
Feb-98	485.53	719.10	511	
Mar-98	519.32	756.60	526	
Apr-98	426.18	458.60	434	
May-98	407.38	270.60	419	
Jun-98	391.14	119.50	400	
Jul-98	390.86	111.60	391	
Aug-98	376.39	189.20	371	
Sep-98	419.40	327.80	417	
Oct-98	434.86	557.70	431	
Nov-98	467.71	792.30	473	
Dec-98	381.25	1051.80	363	
Jan-99	556.79	1183.10	537	
Feb-99	538.03	976.40	507	
Mar-99	528.31	734.00	540	
Apr-99	454.14	508.80	451	
May-99	371.97	391.90	357	
Jun-99	392.64	153.90	394	
Jul-99	444.38	108.60	445	
Aug-99	361.36	145.70	366	
Sep-99	427.53	311.20	428	
Oct-99	443.01	499.80	452	
Nov-99	486.75	792.50	492	
Dec-99	457.62	844.00	485	
Jan-00	659.64	1082.90	662	
Feb-00	429.70	735.20	452	
Mar-00	459.54	659.20	487	
Apr-00	425.46	515.60	421	
May-00	459.06	382.00	446	
Jun-00	439.88	172.50	437	
Jul-00	460.75	142.10	454	
Aug-00	421.70	219.90	410	
Sep-00	417.62	354.20	409	
Oct-00	463.85	539.20	464	
Nov-00	495.43	691.20	523	
Dec-00	597.34	977.80	596	
Jan-01	459.64	722.70	541	
Feb-01	424.66	864.10	418	
Mar-01	478.15	765.30	483	
Apr-01	416.66	506.80	414	
May-01	479.80	390.40	465	
Jun-01	499.99	167.30	499	
Jul-01	430.57	139.60	425	
Aug-01	407.80	139.60	414	
Sep-01	465.47	309.00	467	
Oct-01	467.67	573.40	461	
Nov-01	492.48	818.00	492	
Dec-01	585.11	1094.60	558	
Jan-02	652.56	935.60	687	
Feb-02	543.74	824.60	546	
Mar-02	535.00	921.10	505	
Apr-02	602.74	653.30	567	
May-02	465.03	361.60	456	
Jun-02	415.04	175.60	412	
Jul-02	475.03	130.90	471	
Aug-02	427.53	182.80	424	
Sep-02	473.96	314.40	474	
Oct-02	499.51	444.30	521	
Nov-02	569.87	582.60	621	
Dec-02	501.99	845.20	529	

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Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	650.35	989.10	673	
Feb-03	459.59	756.60	477	
Mar-03	509.70	834.50	499	
Apr-03	427.03	514.30	422	
May-03	417.94	363.70	409	
Jun-03	457.03	192.80	450	
Jul-03	419.88	84.40	426	
Aug-03	405.08	180.60	402	
Sep-03	497.59	359.20	488	
Oct-03	431.58	466.70	448	
Nov-03	551.07	874.60	538	
Dec-03	641.68	911.60	655	
Jan-04	553.93	1257.90	517	
Feb-04	588.61	697.20	619	
Mar-04	545.28	753.50	552	
Apr-04	524.71	466.60	531	
May-04	424.15	272.50	435	
Jun-04	419.00	83.70	436	
Jul-04	388.09	74.20	397	
Aug-04	435.21	101.70	449	
Sep-04	402.16	367.50	391	
Oct-04	383.32	540.50	383	
Nov-04	489.42	719.80	511	
Dec-04	460.83	899.50	476	
Jan-05	674.26	1165.80	658	
Feb-05	513.32	795.20	522	
Mar-05	456.36	613.70	494	
Apr-05	466.43	453.30	475	
May-05	438.62	256.60	453	
Jun-05	416.84	154.40	418	
Jul-05	341.25	132.60	337	
Aug-05	420.90	150.80	424	
Sep-05	415.08	299.30	419	
Oct-05	420.50	534.60	422	
Nov-05	488.13	762.60	500	
Dec-05	513.11	794.40	552	
Jan-06	690.78	1096.20	690	
Feb-06	583.41	821.30	586	
Mar-06	586.70	906.30	560	
Apr-06	511.24	519.10	506	
May-06	521.14	346.90	516	
Jun-06	402.97	173.10	400	
Jul-06	408.76	118.40	408	
Aug-06	449.72	201.60	442	
Sep-06	444.88	295.70	449	
Oct-06	451.06	520.50	456	
Nov-06	590.73	1162.20	515	
Dec-06	646.43	824.30	678	
Jan-07	836.41	912.00	876	
Feb-07	608.51	998.80	572	
Mar-07	654.62	954.20	617	
Apr-07	618.36	511.90	614	
May-07	584.69	322.10	585	
Jun-07	468.06	140.50	473	
Jul-07	512.12	102.30	514	
Aug-07	265.04	154.20	268	
Sep-07	427.81	308.40	429	
Oct-07	465.07	543.70	464	
Nov-07	559.47	724.60	580	
Dec-07	556.70	1069.50	535	

Yukon Electrical Company Limited
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Destruction Bay Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	727.49	1113.80	723	
Feb-08	561.57	954.60	535	
Mar-08	613.78	734.70	625	
Apr-08	582.56	517.30	577	
May-08	523.88	307.90	527	
Jun-08	516.18	225.60	502	
Jul-08	411.51	173.40	398	
Aug-08	437.22	187.70	432	
Sep-08	417.29	318.70	417	
Oct-08	387.33	563.00	383	
Nov-08	557.02	782.50	565	
Dec-08	551.78	1186.20	504	
Jan-09	747.87	1137.90	738	
Feb-09	630.79	955.40	604	
Mar-09	592.23	868.50	574	
Apr-09	615.90	515.20	611	
May-09	470.80	331.20	469	
Jun-09	430.29	144.10	434	
Jul-09	446.52	62.50	458	
Aug-09	374.36	158.30	376	
Sep-09	452.88	306.10	455	
Oct-09	443.99	541.80	444	
Nov-09	562.05	781.50	570	
Dec-09	566.49	943.40	572	
Jan-10	832.12	991.10	854	
Feb-10	600.72	679.20	635	
Mar-10	516.74	656.00	545	
Apr-10	616.28	461.20	623	
May-10	516.82	292.00	523	
Jun-10	422.30	171.90	420	
Jul-10	439.59	117.30	439	
Aug-10	302.70	146.20	307	
Sep-10	450.83	332.40	447	
Oct-10	493.99	520.40	499	
Nov-10	589.14	717.60	611	
Dec-10	591.44	1162.50	549	6452.46
Jan-11	748.39	1010.20	767	
Feb-11	732.11	905.60	716	
Mar-11	655.86	901.70	630	
Apr-11	625.01	511.20	621	
May-11	486.39	296.20	492	
Jun-11	448.66	161.00	449	
Jul-11	403.85	127.80	401	
Aug-11	399.74	217.90	388	
Sep-11	475.29	328.50	472	
Nov-11	506.92	513.30	513	
Nov-11	523.42	936.25	497	
Dec-11	729.11	775.10	772	6718.31
Jan-12	831.41	1118.10	826	
Feb-12	684.62	707.50	713	
Mar-12	693.23	756.20	700	
Apr-12	505.55	450.60	515	
May-12	454.85	350.80	449	
Jun-12	550.67	200.00	542	
Jul-12	435.97	140.10	430	
Aug-12	459.09	157.90	461	
Sep-12	445.74	287.15	452	
Oct-12	486.15	631.40	466	
Nov-12	574.91	969.60	541	
Dec-12	799.31	1196.80	749	6843.09
2013-F				6,671.3
2014-F				6,671.3
2015-F				6,671.3

Yukon Electrical Company Limited
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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1144.75	1165.70	1,115	
Feb-98	879.34	719.10	926	
Mar-98	511.17	756.60	523	
Apr-98	673.26	458.60	687	
May-98	539.35	270.60	560	
Jun-98	498.14	119.50	515	
Jul-98	569.92	111.60	571	
Aug-98	552.94	189.20	543	
Sep-98	489.27	327.80	484	
Oct-98	680.98	557.70	674	
Nov-98	795.49	792.30	806	
Dec-98	789.62	1051.80	756	
Jan-99	927.15	1183.10	890	
Feb-99	743.00	976.40	685	
Mar-99	735.92	734.00	757	
Apr-99	667.80	508.80	661	
May-99	531.03	391.90	503	
Jun-99	552.43	153.90	555	
Jul-99	546.28	108.60	548	
Aug-99	438.29	145.70	447	
Sep-99	584.66	311.20	586	
Oct-99	603.78	499.80	621	
Nov-99	711.25	792.50	721	
Dec-99	919.70	844.00	971	
Jan-00	816.58	1082.90	820	
Feb-00	788.80	735.20	829	
Mar-00	676.58	659.20	728	
Apr-00	596.98	515.60	588	
May-00	618.73	382.00	594	
Jun-00	523.47	172.50	519	
Jul-00	554.25	142.10	542	
Aug-00	503.78	219.90	482	
Sep-00	598.14	354.20	582	
Oct-00	638.83	539.20	640	
Nov-00	671.18	691.20	722	
Dec-00	734.21	977.80	731	
Jan-01	856.02	722.70	1,007	
Feb-01	692.23	864.10	680	
Mar-01	636.65	765.30	645	
Apr-01	617.46	506.80	612	
May-01	593.56	390.40	566	
Jun-01	551.68	167.30	549	
Jul-01	511.08	139.60	500	
Aug-01	597.97	139.60	609	
Sep-01	651.75	309.00	654	
Oct-01	682.88	573.40	670	
Nov-01	743.42	818.00	743	
Dec-01	763.23	1094.60	712	
Jan-02	921.80	935.60	986	
Feb-02	792.95	824.60	797	
Mar-02	744.35	921.10	689	
Apr-02	839.64	653.30	774	
May-02	576.61	361.60	560	
Jun-02	514.92	175.60	509	
Jul-02	528.76	130.90	521	
Aug-02	521.16	182.80	514	
Sep-02	536.78	314.40	537	
Oct-02	655.21	444.30	695	
Nov-02	667.65	582.60	763	
Dec-02	652.76	845.20	704	

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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	1051.67	989.10	1,094	
Feb-03	753.97	756.60	786	
Mar-03	668.50	834.50	648	
Apr-03	711.85	514.30	703	
May-03	594.25	363.70	577	
Jun-03	537.02	192.80	524	
Jul-03	552.81	84.40	564	
Aug-03	559.42	180.60	553	
Sep-03	590.49	359.20	573	
Oct-03	579.49	466.70	610	
Nov-03	852.01	874.60	829	
Dec-03	838.29	911.60	862	
Jan-04	1057.46	1257.90	990	
Feb-04	855.01	697.20	911	
Mar-04	803.16	753.50	816	
Apr-04	868.10	466.60	879	
May-04	572.62	272.50	593	
Jun-04	535.48	83.70	567	
Jul-04	601.46	74.20	617	
Aug-04	517.93	101.70	544	
Sep-04	622.13	367.50	601	
Oct-04	610.32	540.50	611	
Nov-04	715.21	719.80	755	
Dec-04	1006.16	899.50	1,035	
Jan-05	1000.46	1165.80	971	
Feb-05	928.86	795.20	945	
Mar-05	741.70	613.70	812	
Apr-05	691.10	453.30	707	
May-05	571.96	256.60	599	
Jun-05	603.88	154.40	606	
Jul-05	527.80	132.60	520	
Aug-05	525.03	150.80	531	
Sep-05	591.35	299.30	598	
Oct-05	636.62	534.60	639	
Nov-05	714.13	762.60	736	
Dec-05	800.30	794.40	872	
Jan-06	1004.65	1096.20	1,003	
Feb-06	976.21	821.30	982	
Mar-06	988.24	906.30	939	
Apr-06	708.01	519.10	697	
May-06	585.97	346.90	576	
Jun-06	602.91	173.10	598	
Jul-06	487.78	118.40	486	
Aug-06	532.01	201.60	517	
Sep-06	631.19	295.70	639	
Oct-06	615.55	520.50	624	
Nov-06	692.12	1162.20	552	
Dec-06	925.52	824.30	985	
Jan-07	1060.67	912.00	1,134	
Feb-07	841.01	998.80	774	
Mar-07	1041.74	954.20	973	
Apr-07	827.13	511.90	819	
May-07	614.63	322.10	615	
Jun-07	687.44	140.50	696	
Jul-07	563.43	102.30	568	
Aug-07	582.03	154.20	587	
Sep-07	540.50	308.40	543	
Oct-07	682.49	543.70	681	
Nov-07	754.70	724.60	792	
Dec-07	791.70	1069.50	751	

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Beaver Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	946.60	1113.80	938	
Feb-08	996.79	954.60	948	
Mar-08	717.75	734.70	738	
Apr-08	730.91	517.30	721	
May-08	635.69	307.90	641	
Jun-08	607.28	225.60	581	
Jul-08	563.62	173.40	539	
Aug-08	644.32	187.70	635	
Sep-08	532.27	318.70	531	
Oct-08	617.15	563.00	608	
Nov-08	772.11	782.50	786	
Dec-08	1011.94	1186.20	924	
Jan-09	945.57	1137.90	927	
Feb-09	924.94	955.40	876	
Mar-09	833.86	868.50	800	
Apr-09	741.12	515.20	732	
May-09	584.15	331.20	580	
Jun-09	499.03	144.10	506	
Jul-09	609.51	62.50	630	
Aug-09	588.94	158.30	592	
Sep-09	590.61	306.10	594	
Oct-09	691.68	541.80	691	
Nov-09	787.30	781.50	802	
Dec-09	846.34	943.40	857	
Jan-10	1096.43	991.10	1,138	
Feb-10	876.39	679.20	940	
Mar-10	815.75	656.00	868	
Apr-10	743.03	461.20	756	
May-10	694.12	292.00	706	
Jun-10	564.29	171.90	560	
Jul-10	611.61	117.30	610	
Aug-10	629.85	146.20	638	
Sep-10	568.33	332.40	561	
Oct-10	662.11	520.40	671	
Nov-10	677.58	717.60	718	
Dec-10	786.73	1162.50	708	8873.71
Jan-11	1133.18	1010.20	1,167	
Feb-11	866.96	905.60	838	
Mar-11	865.69	901.70	818	
Apr-11	724.28	511.20	717	
May-11	611.99	296.20	622	
Jun-11	533.41	161.00	533	
Jul-11	603.68	127.80	598	
Aug-11	606.01	217.90	585	
Sep-11	594.50	328.50	589	
Nov-11	674.03	513.30	685	
Nov-11	886.06	936.25	837	
Dec-11	1049.39	775.10	1,129	9118.80
Jan-12	1099.68	1118.10	1,089	
Feb-12	902.13	707.50	954	
Mar-12	862.06	756.20	874	
Apr-12	668.21	450.60	686	
May-12	644.93	350.80	633	
Jun-12	658.48	200.00	643	
Jul-12	560.48	140.10	549	
Aug-12	608.08	157.90	611	
Sep-12	595.85	287.15	607	
Oct-12	716.23	631.40	679	
Nov-12	872.74	969.60	811	
Dec-12	1057.34	1196.80	965	9101.26
2013-F				9,031.3
2014-F				9,031.3
2015-F				9,031.3

Yukon Electrical Company Limited
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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	568.72	1165.70	551	
Feb-98	390.62	719.10	418	
Mar-98	359.52	756.60	366	
Apr-98	335.08	458.60	343	
May-98	295.19	270.60	307	
Jun-98	269.54	119.50	279	
Jul-98	307.02	111.60	307	
Aug-98	284.27	189.20	279	
Sep-98	300.45	327.80	297	
Oct-98	340.74	557.70	337	
Nov-98	348.62	792.30	354	
Dec-98	377.59	1051.80	358	
Jan-99	537.10	1183.10	516	
Feb-99	423.80	976.40	390	
Mar-99	374.64	734.00	387	
Apr-99	372.71	508.80	369	
May-99	292.18	391.90	276	
Jun-99	271.03	153.90	273	
Jul-99	306.15	108.60	307	
Aug-99	280.95	145.70	286	
Sep-99	295.00	311.20	296	
Oct-99	287.72	499.80	298	
Nov-99	312.59	792.50	318	
Dec-99	373.56	844.00	403	
Jan-00	453.57	1082.90	456	
Feb-00	337.29	735.20	361	
Mar-00	324.96	659.20	355	
Apr-00	308.29	515.60	303	
May-00	298.64	382.00	284	
Jun-00	262.97	172.50	260	
Jul-00	275.80	142.10	269	
Aug-00	299.81	219.90	287	
Sep-00	274.55	354.20	265	
Oct-00	269.64	539.20	270	
Nov-00	291.25	691.20	321	
Dec-00	367.92	977.80	366	
Jan-01	343.68	722.70	431	
Feb-01	359.34	864.10	352	
Mar-01	303.10	765.30	308	
Apr-01	284.31	506.80	281	
May-01	273.10	390.40	257	
Jun-01	241.49	167.30	240	
Jul-01	256.79	139.60	250	
Aug-01	278.56	139.60	285	
Sep-01	261.86	309.00	263	
Oct-01	274.62	573.40	267	
Nov-01	324.16	818.00	324	
Dec-01	439.49	1094.60	410	
Jan-02	419.66	935.60	457	
Feb-02	352.27	824.60	355	
Mar-02	321.00	921.10	289	
Apr-02	314.88	653.30	277	
May-02	283.33	361.60	274	
Jun-02	248.35	175.60	245	
Jul-02	272.12	130.90	268	
Aug-02	290.73	182.80	287	
Sep-02	253.23	314.40	253	
Oct-02	299.37	444.30	322	
Nov-02	317.13	582.60	373	
Dec-02	368.73	845.20	398	

Yukon Electrical Company Limited
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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	438.03	989.10	463	
Feb-03	352.66	756.60	371	
Mar-03	336.25	834.50	325	
Apr-03	313.80	514.30	309	
May-03	281.55	363.70	272	
Jun-03	255.82	192.80	248	
Jul-03	287.82	84.40	295	
Aug-03	270.46	180.60	267	
Sep-03	277.39	359.20	267	
Oct-03	243.60	466.70	261	
Nov-03	263.42	874.60	250	
Dec-03	376.97	911.60	391	
Jan-04	426.31	1257.90	387	
Feb-04	377.81	697.20	410	
Mar-04	340.32	753.50	348	
Apr-04	360.04	466.60	366	
May-04	281.20	272.50	293	
Jun-04	250.25	83.70	269	
Jul-04	291.10	74.20	300	
Aug-04	256.88	101.70	272	
Sep-04	317.18	367.50	305	
Oct-04	304.78	540.50	305	
Nov-04	336.15	719.80	359	
Dec-04	375.44	899.50	392	
Jan-05	532.50	1165.80	515	
Feb-05	428.12	795.20	437	
Mar-05	324.57	613.70	365	
Apr-05	316.33	453.30	326	
May-05	271.63	256.60	287	
Jun-05	252.45	154.40	254	
Jul-05	286.19	132.60	282	
Aug-05	300.47	150.80	304	
Sep-05	276.06	299.30	280	
Oct-05	312.45	534.60	314	
Nov-05	346.21	762.60	359	
Dec-05	412.04	794.40	454	
Jan-06	549.87	1096.20	549	
Feb-06	435.94	821.30	439	
Mar-06	453.87	906.30	425	
Apr-06	380.81	519.10	375	
May-06	327.13	346.90	321	
Jun-06	262.47	173.10	260	
Jul-06	320.19	118.40	319	
Aug-06	276.52	201.60	268	
Sep-06	308.15	295.70	313	
Oct-06	325.52	520.50	330	
Nov-06	424.64	1162.20	343	
Dec-06	526.02	824.30	561	
Jan-07	596.08	912.00	639	
Feb-07	549.43	998.80	510	
Mar-07	455.28	954.20	415	
Apr-07	357.51	511.90	353	
May-07	332.11	322.10	332	
Jun-07	297.45	140.50	302	
Jul-07	285.50	102.30	288	
Aug-07	297.61	154.20	300	
Sep-07	297.38	308.40	299	
Oct-07	340.93	543.70	340	
Nov-07	470.95	724.60	493	
Dec-07	509.59	1069.50	486	

Yukon Electrical Company Limited
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Tagish Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	529.39	1113.80	524	
Feb-08	605.05	954.60	577	
Mar-08	413.02	734.70	425	
Apr-08	340.57	517.30	335	
May-08	289.64	307.90	293	
Jun-08	281.46	225.60	266	
Jul-08	269.32	173.40	255	
Aug-08	319.52	187.70	314	
Sep-08	293.14	318.70	292	
Oct-08	317.14	563.00	312	
Nov-08	489.59	782.50	498	
Dec-08	511.70	1186.20	460	
Jan-09	688.78	1137.90	678	
Feb-09	556.80	955.40	528	
Mar-09	490.70	868.50	471	
Apr-09	425.92	515.20	421	
May-09	291.63	331.20	289	
Jun-09	270.57	144.10	275	
Jul-09	322.52	62.50	335	
Aug-09	280.87	158.30	283	
Sep-09	303.99	306.10	306	
Oct-09	385.39	541.80	385	
Nov-09	451.41	781.50	460	
Dec-09	512.91	943.40	519	
Jan-10	631.26	991.10	655	
Feb-10	511.78	679.20	549	
Mar-10	425.32	656.00	456	
Apr-10	423.81	461.20	431	
May-10	351.03	292.00	358	
Jun-10	281.45	171.90	279	
Jul-10	316.55	117.30	316	
Aug-10	311.28	146.20	316	
Sep-10	336.06	332.40	332	
Oct-10	414.58	520.40	419	
Nov-10	417.00	717.60	441	
Dec-10	536.77	1162.50	491	5042.87
Jan-11	730.78	1010.20	750	
Feb-11	521.04	905.60	504	
Mar-11	548.00	901.70	520	
Apr-11	392.61	511.20	388	
May-11	364.87	296.20	371	
Jun-11	286.41	161.00	286	
Jul-11	324.11	127.80	321	
Aug-11	317.59	217.90	305	
Sep-11	343.45	328.50	340	
Nov-11	361.83	513.30	368	
Nov-11	517.46	936.25	489	
Dec-11	494.27	775.10	540	5184.71
Jan-12	700.79	1118.10	695	
Feb-12	507.40	707.50	538	
Mar-12	504.90	756.20	512	
Apr-12	345.99	450.60	356	
May-12	352.07	350.80	345	
Jun-12	348.46	200.00	339	
Jul-12	314.99	140.10	309	
Aug-12	344.42	157.90	346	
Sep-12	333.82	287.15	340	
Oct-12	414.21	631.40	393	
Nov-12	513.07	969.60	477	
Dec-12	637.55	1196.80	584	5233.20
2013-F				5,153.6
2014-F				5,153.6
2015-F				5,153.6

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	922.61	1165.70	888	
Feb-98	719.54	719.10	774	
Mar-98	633.42	756.60	647	
Apr-98	589.41	458.60	606	
May-98	493.54	270.60	518	
Jun-98	439.08	119.50	459	
Jul-98	487.36	111.60	488	
Aug-98	466.85	189.20	456	
Sep-98	554.45	327.80	548	
Oct-98	560.71	557.70	553	
Nov-98	655.54	792.30	667	
Dec-98	886.52	1051.80	848	
Jan-99	906.99	1183.10	864	
Feb-99	812.23	976.40	745	
Mar-99	660.72	734.00	685	
Apr-99	615.38	508.80	608	
May-99	514.03	391.90	481	
Jun-99	473.06	153.90	476	
Jul-99	461.31	108.60	463	
Aug-99	428.75	145.70	438	
Sep-99	511.22	311.20	513	
Oct-99	517.48	499.80	537	
Nov-99	589.23	792.50	601	
Dec-99	824.03	844.00	884	
Jan-00	828.68	1082.90	833	
Feb-00	665.54	735.20	713	
Mar-00	578.48	659.20	638	
Apr-00	569.25	515.60	559	
May-00	525.15	382.00	497	
Jun-00	429.62	172.50	424	
Jul-00	451.81	142.10	438	
Aug-00	493.73	219.90	468	
Sep-00	501.65	354.20	483	
Oct-00	580.63	539.20	582	
Nov-00	591.03	691.20	651	
Dec-00	788.26	977.80	784	
Jan-01	714.57	722.70	890	
Feb-01	674.39	864.10	660	
Mar-01	609.15	765.30	619	
Apr-01	560.93	506.80	554	
May-01	554.49	390.40	522	
Jun-01	444.60	167.30	442	
Jul-01	480.68	139.60	468	
Aug-01	438.08	139.60	451	
Sep-01	452.60	309.00	456	
Oct-01	571.87	573.40	557	
Nov-01	642.53	818.00	642	
Dec-01	910.51	1094.60	851	
Jan-02	805.85	935.60	880	
Feb-02	644.89	824.60	650	
Mar-02	627.55	921.10	563	
Apr-02	658.99	653.30	583	
May-02	505.70	361.60	487	
Jun-02	445.33	175.60	438	
Jul-02	445.86	130.90	437	
Aug-02	465.07	182.80	457	
Sep-02	463.34	314.40	464	
Oct-02	559.59	444.30	606	
Nov-02	576.02	582.60	687	
Dec-02	744.72	845.20	804	

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	772.78	989.10	822	
Feb-03	611.36	756.60	648	
Mar-03	600.85	834.50	577	
Apr-03	602.07	514.30	592	
May-03	459.68	363.70	440	
Jun-03	450.12	192.80	435	
Jul-03	466.38	84.40	480	
Aug-03	455.98	180.60	449	
Sep-03	521.70	359.20	501	
Oct-03	492.29	466.70	528	
Nov-03	697.32	874.60	670	
Dec-03	822.87	911.60	851	
Jan-04	807.21	1257.90	729	
Feb-04	657.43	697.20	723	
Mar-04	618.36	753.50	633	
Apr-04	623.60	466.60	636	
May-04	482.32	272.50	506	
Jun-04	494.34	83.70	531	
Jul-04	457.03	74.20	475	
Aug-04	460.76	101.70	491	
Sep-04	524.11	367.50	499	
Oct-04	543.78	540.50	544	
Nov-04	634.98	719.80	681	
Dec-04	834.53	899.50	868	
Jan-05	869.05	1165.80	834	
Feb-05	755.37	795.20	774	
Mar-05	604.75	613.70	686	
Apr-05	524.07	453.30	543	
May-05	521.30	256.60	552	
Jun-05	451.77	154.40	455	
Jul-05	473.22	132.60	464	
Aug-05	476.85	150.80	484	
Sep-05	513.36	299.30	521	
Oct-05	533.60	534.60	537	
Nov-05	699.34	762.60	725	
Dec-05	774.39	794.40	858	
Jan-06	848.61	1096.20	847	
Feb-06	796.05	821.30	802	
Mar-06	757.64	906.30	700	
Apr-06	581.66	519.10	569	
May-06	548.72	346.90	537	
Jun-06	461.75	173.10	456	
Jul-06	466.02	118.40	463	
Aug-06	508.04	201.60	491	
Sep-06	526.65	295.70	536	
Oct-06	582.31	520.50	592	
Nov-06	880.03	1162.20	716	
Dec-06	885.09	824.30	954	
Jan-07	895.16	912.00	981	
Feb-07	874.50	998.80	796	
Mar-07	718.47	954.20	638	
Apr-07	588.70	511.90	580	
May-07	496.13	322.10	496	
Jun-07	474.10	140.50	484	
Jul-07	480.39	102.30	485	
Aug-07	512.91	154.20	518	
Sep-07	497.29	308.40	501	
Oct-07	644.31	543.70	643	
Nov-07	795.58	724.60	839	
Dec-07	899.95	1069.50	853	

Yukon Electrical Company Limited
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Marsh Lake Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	975.11	1113.80	965	
Feb-08	955.69	954.60	899	
Mar-08	727.86	734.70	752	
Apr-08	658.41	517.30	647	
May-08	525.74	307.90	532	
Jun-08	487.43	225.60	457	
Jul-08	470.87	173.40	442	
Aug-08	556.13	187.70	546	
Sep-08	518.14	318.70	517	
Oct-08	593.70	563.00	583	
Nov-08	844.54	782.50	861	
Dec-08	1073.85	1186.20	971	
Jan-09	1064.61	1137.90	1,043	
Feb-09	918.50	955.40	861	
Mar-09	851.77	868.50	812	
Apr-09	765.56	515.20	755	
May-09	500.95	331.20	497	
Jun-09	493.95	144.10	502	
Jul-09	502.61	62.50	527	
Aug-09	471.85	158.30	475	
Sep-09	559.26	306.10	564	
Oct-09	611.99	541.80	612	
Nov-09	771.66	781.50	789	
Dec-09	1004.31	943.40	1,017	
Jan-10	987.15	991.10	1,035	
Feb-10	811.06	679.20	885	
Mar-10	737.86	656.00	799	
Apr-10	707.72	461.20	723	
May-10	561.34	292.00	576	
Jun-10	472.98	171.90	468	
Jul-10	525.23	117.30	523	
Aug-10	498.35	146.20	508	
Sep-10	621.63	332.40	613	
Oct-10	671.29	520.40	681	
Nov-10	761.67	717.60	809	
Dec-10	991.46	1162.50	900	8519.99
Jan-11	1273.29	1010.20	1,312	
Feb-11	915.97	905.60	882	
Mar-11	936.96	901.70	882	
Apr-11	777.29	511.20	769	
May-11	606.37	296.20	619	
Jun-11	516.93	161.00	517	
Jul-11	490.14	127.80	483	
Aug-11	558.09	217.90	533	
Sep-11	583.69	328.50	577	
Nov-11	658.14	513.30	671	
Nov-11	874.10	936.25	817	
Dec-11	1081.26	775.10	1,174	9236.76
Jan-12	1122.06	1118.10	1,110	
Feb-12	981.19	707.50	1,042	
Mar-12	814.35	756.20	828	
Apr-12	631.96	450.60	652	
May-12	635.15	350.80	621	
Jun-12	526.83	200.00	508	
Jul-12	509.33	140.10	496	
Aug-12	583.43	157.90	587	
Sep-12	558.34	287.15	572	
Oct-12	702.15	631.40	659	
Nov-12	949.97	969.60	877	
Dec-12	1294.29	1196.80	1,186	9139.81
2013-F				8,965.5
2014-F				8,965.5
2015-F				8,965.5

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Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	906.21	1165.70	879.57	
Feb-98	638.94	719.10	680.91	
Mar-98	763.85	756.60	774.25	
Apr-98	559.58	458.60	572.12	
May-98	412.38	270.60	431.08	
Jun-98	347.61	119.50	362.63	
Jul-98	401.03	111.60	401.55	
Aug-98	457.29	189.20	448.80	
Sep-98	401.65	327.80	397.08	
Oct-98	605.18	557.70	599.14	
Nov-98	676.97	792.30	685.95	
Dec-98	731.56	1051.80	701.75	
Jan-99	943.04	1183.10	910	
Feb-99	797.96	976.40	746	
Mar-99	523.43	734.00	542	
Apr-99	442.96	508.80	437	
May-99	379.52	391.90	354	
Jun-99	308.64	153.90	311	
Jul-99	321.09	108.60	323	
Aug-99	273.18	145.70	281	
Sep-99	370.68	311.20	372	
Oct-99	352.64	499.80	368	
Nov-99	450.04	792.50	459	
Dec-99	477.70	844.00	523	
Jan-00	805.58	1082.90	809	
Feb-00	503.88	735.20	540	
Mar-00	419.58	659.20	465	
Apr-00	463.79	515.60	456	
May-00	329.30	382.00	307	
Jun-00	274.71	172.50	270	
Jul-00	324.96	142.10	314	
Aug-00	293.78	219.90	274	
Sep-00	353.82	354.20	340	
Oct-00	380.95	539.20	382	
Nov-00	428.87	691.20	475	
Dec-00	701.70	977.80	699	
Jan-01	393.70	722.70	528	
Feb-01	532.00	864.10	521	
Mar-01	446.39	765.30	454	
Apr-01	443.87	506.80	439	
May-01	309.96	390.40	285	
Jun-01	297.65	167.30	295	
Jul-01	251.04	139.60	241	
Aug-01	206.42	139.60	216	
Sep-01	326.21	309.00	328	
Oct-01	288.08	573.40	276	
Nov-01	428.08	818.00	428	
Dec-01	610.00	1094.60	565	
Jan-02	648.79	935.60	706	
Feb-02	478.50	824.60	482	
Mar-02	420.75	921.10	371	
Apr-02	336.54	653.30	278	
May-02	292.92	361.60	279	
Jun-02	217.63	175.60	212	
Jul-02	243.21	130.90	237	
Aug-02	280.83	182.80	275	
Sep-02	238.42	314.40	239	
Oct-02	308.20	444.30	343	
Nov-02	409.88	582.60	495	
Dec-02	475.24	845.20	521	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	480.32	989.10	518	
Feb-03	620.92	756.60	649	
Mar-03	448.00	834.50	430	
Apr-03	370.56	514.30	363	
May-03	342.68	363.70	328	
Jun-03	287.88	192.80	276	
Jul-03	351.29	84.40	362	
Aug-03	321.54	180.60	316	
Sep-03	502.45	359.20	486	
Oct-03	342.54	466.70	370	
Nov-03	534.22	874.60	513	
Dec-03	849.17	911.60	870	
Jan-04	987.42	1257.90	927	
Feb-04	833.67	697.20	884	
Mar-04	625.29	753.50	637	
Apr-04	544.58	466.60	554	
May-04	387.75	272.50	406	
Jun-04	338.42	83.70	366	
Jul-04	342.38	74.20	357	
Aug-04	333.40	101.70	357	
Sep-04	391.08	367.50	372	
Oct-04	462.92	540.50	463	
Nov-04	607.00	719.80	642	
Dec-04	430.42	899.50	456	
Jan-05	799.25	1165.80	773	
Feb-05	616.25	795.20	631	
Mar-05	488.39	613.70	551	
Apr-05	432.06	453.30	447	
May-05	302.50	256.60	326	
Jun-05	415.44	154.40	418	
Jul-05	332.69	132.60	326	
Aug-05	403.48	150.80	409	
Sep-05	350.66	299.30	356	
Oct-05	368.41	534.60	371	
Nov-05	377.39	762.60	397	
Dec-05	382.15	794.40	446	
Jan-06	486.15	1096.20	485	
Feb-06	684.48	821.30	689	
Mar-06	472.24	906.30	428	
Apr-06	422.03	519.10	413	
May-06	422.56	346.90	414	
Jun-06	420.13	173.10	416	
Jul-06	362.21	118.40	360	
Aug-06	315.26	201.60	302	
Sep-06	380.33	295.70	387	
Oct-06	339.06	520.50	347	
Nov-06	460.60	1162.20	335	
Dec-06	658.26	824.30	711	
Jan-07	812.80	912.00	878	
Feb-07	624.60	998.80	565	
Mar-07	600.89	954.20	539	
Apr-07	602.97	511.90	596	
May-07	320.69	322.10	321	
Jun-07	347.81	140.50	355	
Jul-07	350.89	102.30	355	
Aug-07	318.14	154.20	322	
Sep-07	372.57	308.40	375	
Oct-07	326.69	543.70	326	
Nov-07	511.03	724.60	545	
Dec-07	390.59	1069.50	354	

Yukon Electrical Company Limited
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Deep Creek Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	669.92	1113.80	662	
Feb-08	644.32	954.60	601	
Mar-08	464.41	734.70	483	
Apr-08	431.89	517.30	423	
May-08	395.39	307.90	401	
Jun-08	298.92	225.60	275	
Jul-08	310.56	173.40	289	
Aug-08	355.80	187.70	348	
Sep-08	302.62	318.70	301	
Oct-08	282.58	563.00	275	
Nov-08	521.36	782.50	534	
Dec-08	517.43	1186.20	439	
Jan-09	803.71	1137.90	787	
Feb-09	443.17	955.40	399	
Mar-09	477.46	868.50	447	
Apr-09	271.33	515.20	263	
May-09	224.88	331.20	222	
Jun-09	275.81	144.10	282	
Jul-09	292.86	62.50	311	
Aug-09	277.24	158.30	280	
Sep-09	343.81	306.10	347	
Oct-09	352.12	541.80	352	
Nov-09	337.55	781.50	350	
Dec-09	340.86	943.40	350	
Jan-10	598.31	991.10	635	
Feb-10	387.39	679.20	444	
Mar-10	373.39	656.00	420	
Apr-10	436.93	461.20	449	
May-10	324.41	292.00	335	
Jun-10	280.33	171.90	276	
Jul-10	314.88	117.30	313	
Aug-10	287.07	146.20	294	
Sep-10	361.88	332.40	356	
Oct-10	383.38	520.40	391	
Nov-10	407.80	717.60	444	
Dec-10	482.51	1162.50	412	4770.11
Jan-11	703.02	1010.20	733	
Feb-11	581.05	905.60	555	
Mar-11	733.63	901.70	691	
Apr-11	517.78	511.20	511	
May-11	392.76	296.20	402	
Jun-11	326.12	161.00	326	
Jul-11	280.35	127.80	275	
Aug-11	284.50	217.90	266	
Sep-11	376.95	328.50	372	
Nov-11	445.03	513.30	455	
Nov-11	503.27	936.25	460	
Dec-11	658.38	775.10	729	5775.67
Jan-12	744.80	1118.10	735	
Feb-12	761.55	707.50	808	
Mar-12	642.83	756.20	653	
Apr-12	541.75	450.60	557	
May-12	352.56	350.80	342	
Jun-12	300.41	200.00	286	
Jul-12	305.73	140.10	296	
Aug-12	373.76	157.90	377	
Sep-12	332.63	287.15	343	
Oct-12	372.08	631.40	339	
Nov-12	511.66	969.60	456	
Dec-12	687.90	1196.80	605	5798.13
2013-F				5,448.0
2014-F				5,448.0
2015-F				5,448.0

Yukon Electrical Company Limited
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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1059.13	1409.70	1,002	
Feb-98	791.03	942.00	785	
Mar-98	739.96	843.40	735	
Apr-98	661.48	500.10	664	
May-98	553.52	211.00	584	
Jun-98	504.32	89.00	519	
Jul-98	460.33	65.70	468	
Aug-98	480.62	156.80	476	
Sep-98	569.91	320.70	559	
Oct-98	599.93	561.20	588	
Nov-98	790.29	958.10	761	
Dec-98	788.21	1252.70	726	
Jan-99	934.05	1350.20	898	
Feb-99	773.36	1066.40	724	
Mar-99	711.18	871.40	696	
Apr-99	678.26	506.40	678	
May-99	598.20	372.20	572	
Jun-99	539.70	140.20	536	
Jul-99	478.75	99.40	475	
Aug-99	498.93	127.80	505	
Sep-99	579.53	292.50	579	
Oct-99	577.38	519.80	580	
Nov-99	709.78	939.90	687	
Dec-99	698.42	1013.00	720	
Jan-00	921.12	1344.80	887	
Feb-00	843.97	956.00	833	
Mar-00	688.04	750.10	715	
Apr-00	664.42	590.90	635	
May-00	638.13	373.80	611	
Jun-00	526.49	158.00	517	
Jul-00	542.56	84.30	544	
Aug-00	520.26	216.90	495	
Sep-00	545.37	314.80	537	
Oct-00	616.71	575.80	600	
Nov-00	680.74	858.40	687	
Dec-00	756.54	1222.80	705	
Jan-01	974.72	1043.40	1,046	
Feb-01	692.01	1031.00	655	
Mar-01	683.09	844.90	677	
Apr-01	657.56	535.80	647	
May-01	578.49	366.60	554	
Jun-01	535.74	155.50	527	
Jul-01	505.80	120.30	494	
Aug-01	495.96	120.60	504	
Sep-01	537.17	299.60	534	
Oct-01	597.60	577.00	580	
Nov-01	670.73	975.00	636	
Dec-01	731.64	1275.40	662	
Jan-02	904.19	1246.30	905	
Feb-02	724.91	970.30	709	
Mar-02	724.43	991.60	667	
Apr-02	759.43	694.80	693	
May-02	592.82	365.90	569	
Jun-02	540.27	147.80	534	
Jul-02	468.10	121.60	456	
Aug-02	542.99	181.50	530	
Sep-02	531.50	331.00	517	
Oct-02	576.38	514.80	581	
Nov-02	670.27	821.90	689	
Dec-02	686.08	1117.90	671	

Yukon Electrical Company Limited
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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	883.76	1177.50	908	
Feb-03	664.22	964.70	650	
Mar-03	665.22	899.50	640	
Apr-03	729.91	554.40	713	
May-03	647.82	341.60	632	
Jun-03	475.11	179.90	457	
Jul-03	488.70	56.60	499	
Aug-03	496.69	163.00	490	
Sep-03	533.65	330.20	520	
Oct-03	535.94	526.10	537	
Nov-03	683.69	963.90	652	
Dec-03	725.42	1095.50	718	
Jan-04	846.90	1365.60	805	
Feb-04	805.97	881.20	821	
Mar-04	709.32	809.90	716	
Apr-04	671.18	497.40	674	
May-04	507.37	292.30	509	
Jun-04	561.64	74.10	581	
Jul-04	514.33	35.60	532	
Aug-04	479.73	145.70	479	
Sep-04	510.47	370.70	482	
Oct-04	567.03	565.00	554	
Nov-04	782.65	875.50	782	
Dec-04	801.75	1070.70	803	
Jan-05	1013.04	1330.30	984	
Feb-05	610.26	941.80	604	
Mar-05	632.58	726.90	668	
Apr-05	618.87	464.80	633	
May-05	581.25	256.90	596	
Jun-05	444.66	126.60	446	
Jul-05	493.56	136.90	476	
Aug-05	448.88	162.20	442	
Sep-05	509.23	297.30	507	
Oct-05	621.21	541.70	616	
Nov-05	647.76	758.40	689	
Dec-05	742.88	1061.00	748	
Jan-06	943.00	1185.20	965	
Feb-06	910.37	1016.70	878	
Mar-06	826.74	960.50	780	
Apr-06	714.95	528.20	707	
May-06	583.71	371.10	558	
Jun-06	616.54	136.50	614	
Jul-06	548.45	79.20	551	
Aug-06	556.71	171.70	547	
Sep-06	563.11	292.40	562	
Oct-06	675.43	543.30	670	
Nov-06	837.25	1196.20	725	
Dec-06	906.05	1050.00	915	
Jan-07	1105.27	1102.40	1,156	
Feb-07	908.98	1017.30	876	
Mar-07	920.03	1001.90	859	
Apr-07	949.68	543.00	937	
May-07	681.49	332.20	669	
Jun-07	544.25	122.60	547	
Jul-07	588.79	88.60	588	
Aug-07	533.70	143.10	534	
Sep-07	571.41	314.70	563	
Oct-07	691.25	553.10	683	
Nov-07	797.41	956.60	769	
Dec-07	858.46	1255.10	796	

Yukon Electrical Company Limited
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Lower Post BC Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1143.55	1300.10	1,125	
Feb-08	992.38	1064.20	943	
Mar-08	792.01	833.30	790	
Apr-08	927.25	554.00	911	
May-08	649.38	295.60	650	
Jun-08	584.03	191.00	562	
Jul-08	564.68	131.50	549	
Aug-08	618.23	154.00	615	
Sep-08	578.57	304.20	574	
Oct-08	747.97	523.50	750	
Nov-08	826.82	879.00	825	
Dec-08	851.76	1386.50	743	
Jan-09	1345.06	1329.30	1,316	
Feb-09	1012.90	1089.50	955	
Mar-09	960.47	1054.20	881	
Apr-09	835.74	590.00	806	
May-09	641.94	356.00	622	
Jun-09	535.32	130.60	535	
Jul-09	630.86	89.00	630	
Aug-09	559.61	134.40	563	
Sep-09	676.16	279.40	680	
Oct-09	690.80	606.90	663	
Nov-09	787.50	996.50	745	
Dec-09	955.06	1273.66	886	
Jan-10	1239.27	1141.42	1,276	
Feb-10	900.03	965.80	886	
Mar-10	769.80	763.50	793	
Apr-10	905.06	502.70	906	
May-10	720.61	277.70	728	
Jun-10	557.38	142.70	553	
Jul-10	515.02	70.80	521	
Aug-10	515.88	119.60	524	
Sep-10	586.92	319.65	577	
Oct-10	652.64	516.80	657	
Nov-10	767.08	904.20	757	
Dec-10	981.60	1292.10	906	9082.35
Jan-11	1298.70	1201.00	1,315	
Feb-11	858.98	1004.60	831	
Mar-11	1010.89	1032.90	939	
Apr-11	723.10	587.50	695	
May-11	681.10	271.10	690	
Jun-11	612.67	143.10	608	
Jul-11	541.51	104.40	536	
Aug-11	590.46	195.10	573	
Sep-11	762.19	292.40	761	
Nov-11	651.97	511.90	658	
Nov-11	688.90	1059.10	624	
Dec-11	900.79	1006.30	925	9154.63
Jan-12	1186.89	1273.00	1,178	
Feb-12	898.98	935.50	895	
Mar-12	887.78	909.00	859	
Apr-12	712.02	512.60	710	
May-12	693.08	340.20	678	
Jun-12	486.72	149.70	480	
Jul-12	589.14	77.80	592	
Aug-12	593.11	134.00	597	
Sep-12	362.63	259.40	373	
Oct-12	628.62	714.50	563	
Nov-12	779.84	1112.80	696	
Dec-12	936.60	1356.20	838	8460.61
2013-F				8,899.2
2014-F				8,899.2
2015-F				8,899.2

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	997.90	1409.70	949	
Feb-98	652.96	942.00	648	
Mar-98	552.31	843.40	548	
Apr-98	563.65	500.10	566	
May-98	517.32	211.00	544	
Jun-98	448.82	89.00	461	
Jul-98	459.37	65.70	466	
Aug-98	493.96	156.80	490	
Sep-98	506.27	320.70	497	
Oct-98	554.50	561.20	544	
Nov-98	686.86	958.10	662	
Dec-98	694.52	1252.70	641	
Jan-99	908.00	1350.20	877	
Feb-99	683.08	1066.40	640	
Mar-99	608.71	871.40	596	
Apr-99	622.07	506.40	622	
May-99	501.75	372.20	479	
Jun-99	477.28	140.20	474	
Jul-99	467.05	99.40	463	
Aug-99	479.70	127.80	485	
Sep-99	482.08	292.50	481	
Oct-99	493.59	519.80	496	
Nov-99	739.99	939.90	720	
Dec-99	472.77	1013.00	492	
Jan-00	873.30	1344.80	844	
Feb-00	701.49	956.00	692	
Mar-00	554.63	750.10	578	
Apr-00	606.05	590.90	580	
May-00	547.08	373.80	524	
Jun-00	475.47	158.00	467	
Jul-00	464.64	84.30	466	
Aug-00	484.91	216.90	463	
Sep-00	534.36	314.80	527	
Oct-00	538.38	575.80	524	
Nov-00	591.77	858.40	597	
Dec-00	674.28	1222.80	630	
Jan-01	771.04	1043.40	833	
Feb-01	587.00	1031.00	555	
Mar-01	619.82	844.90	615	
Apr-01	487.01	535.80	478	
May-01	498.88	366.60	478	
Jun-01	481.64	155.50	474	
Jul-01	433.85	120.30	424	
Aug-01	452.74	120.60	460	
Sep-01	451.68	299.60	449	
Oct-01	506.50	577.00	492	
Nov-01	635.83	975.00	606	
Dec-01	694.04	1275.40	634	
Jan-02	745.25	1246.30	746	
Feb-02	714.61	970.30	701	
Mar-02	524.92	991.60	475	
Apr-02	580.34	694.80	523	
May-02	554.03	365.90	533	
Jun-02	417.79	147.80	412	
Jul-02	450.73	121.60	440	
Aug-02	462.56	181.50	451	
Sep-02	452.56	331.00	440	
Oct-02	555.52	514.80	560	
Nov-02	655.39	821.90	671	
Dec-02	586.84	1117.90	574	

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	813.99	1177.50	835	
Feb-03	652.99	964.70	641	
Mar-03	618.83	899.50	597	
Apr-03	618.90	554.40	604	
May-03	551.83	341.60	539	
Jun-03	476.52	179.90	461	
Jul-03	477.44	56.60	487	
Aug-03	494.15	163.00	488	
Sep-03	511.61	330.20	500	
Oct-03	498.63	526.10	499	
Nov-03	740.76	963.90	714	
Dec-03	735.28	1095.50	729	
Jan-04	1028.59	1365.60	993	
Feb-04	704.57	881.20	718	
Mar-04	635.33	809.90	641	
Apr-04	612.84	497.40	616	
May-04	505.48	292.30	507	
Jun-04	452.28	74.10	469	
Jul-04	487.09	35.60	503	
Aug-04	447.41	145.70	447	
Sep-04	522.56	370.70	498	
Oct-04	570.40	565.00	559	
Nov-04	617.92	875.50	618	
Dec-04	637.50	1070.70	639	
Jan-05	942.64	1330.30	918	
Feb-05	624.90	941.80	620	
Mar-05	567.46	726.90	598	
Apr-05	632.60	464.80	645	
May-05	481.28	256.90	494	
Jun-05	440.54	126.60	441	
Jul-05	466.05	136.90	451	
Aug-05	516.55	162.20	511	
Sep-05	585.49	297.30	583	
Oct-05	619.35	541.70	615	
Nov-05	692.66	758.40	728	
Dec-05	789.76	1061.00	794	
Jan-06	953.94	1185.20	973	
Feb-06	818.62	1016.70	791	
Mar-06	786.17	960.50	746	
Apr-06	714.89	528.20	708	
May-06	545.26	371.10	523	
Jun-06	515.27	136.50	513	
Jul-06	499.91	79.20	502	
Aug-06	454.73	171.70	446	
Sep-06	479.72	292.40	479	
Oct-06	613.82	543.30	609	
Nov-06	691.24	1196.20	594	
Dec-06	852.95	1050.00	861	
Jan-07	954.29	1102.40	998	
Feb-07	732.16	1017.30	704	
Mar-07	818.35	1001.90	766	
Apr-07	703.60	543.00	693	
May-07	523.82	332.20	513	
Jun-07	486.55	122.60	489	
Jul-07	494.65	88.60	494	
Aug-07	437.98	143.10	438	
Sep-07	506.63	314.70	499	
Oct-07	538.89	553.10	531	
Nov-07	666.59	956.60	642	
Dec-07	744.78	1255.10	690	

Yukon Electrical Company Limited
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Upper Liard Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1026.05	1300.10	1,010	
Feb-08	874.25	1064.20	832	
Mar-08	661.10	833.30	660	
Apr-08	750.33	554.00	736	
May-08	447.28	295.60	448	
Jun-08	490.71	191.00	472	
Jul-08	540.16	131.50	527	
Aug-08	523.79	154.00	521	
Sep-08	564.57	304.20	560	
Oct-08	622.52	523.50	624	
Nov-08	625.87	879.00	625	
Dec-08	730.65	1386.50	636	
Jan-09	1148.87	1329.30	1,124	
Feb-09	788.55	1089.50	739	
Mar-09	857.23	1054.20	789	
Apr-09	627.08	590.00	602	
May-09	697.31	356.00	680	
Jun-09	552.88	130.60	553	
Jul-09	480.71	89.00	480	
Aug-09	522.12	134.40	525	
Sep-09	529.64	279.40	533	
Oct-09	573.91	606.90	550	
Nov-09	700.62	996.50	664	
Dec-09	866.03	1273.66	806	
Jan-10	1036.85	1141.42	1,069	
Feb-10	742.83	965.80	730	
Mar-10	772.14	763.50	792	
Apr-10	645.62	502.70	647	
May-10	533.67	277.70	540	
Jun-10	568.32	142.70	564	
Jul-10	496.39	70.80	501	
Aug-10	501.36	119.60	509	
Sep-10	532.03	319.65	523	
Oct-10	654.48	516.80	658	
Nov-10	640.45	904.20	632	
Dec-10	747.00	1292.10	681	7846.17
Jan-11	987.48	1201.00	1,002	
Feb-11	726.69	1004.60	702	
Mar-11	859.42	1032.90	797	
Apr-11	604.34	587.50	580	
May-11	695.18	271.10	703	
Jun-11	498.84	143.10	495	
Jul-11	465.48	104.40	460	
Aug-11	526.94	195.10	511	
Sep-11	547.95	292.40	547	
Nov-11	602.00	511.90	607	
Nov-11	655.68	1059.10	600	
Dec-11	725.53	1006.30	747	7751.63
Jan-12	996.82	1273.00	989	
Feb-12	694.23	935.50	691	
Mar-12	720.61	909.00	696	
Apr-12	622.83	512.60	621	
May-12	582.21	340.20	569	
Jun-12	516.52	149.70	510	
Jul-12	463.71	77.80	467	
Aug-12	526.65	134.00	530	
Sep-12	530.57	259.40	540	
Oct-12	696.00	714.50	640	
Nov-12	747.74	1112.80	676	
Dec-12	921.21	1356.20	836	7764.49
2013-F				7,787.4
2014-F				7,787.4
2015-F				7,787.4

Yukon Electrical Company Limited
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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-98	1053.77	1409.70	997	
Feb-98	768.05	942.00	762	
Mar-98	702.37	843.40	697	
Apr-98	707.15	500.10	709	
May-98	564.48	211.00	595	
Jun-98	527.32	89.00	541	
Jul-98	523.51	65.70	531	
Aug-98	538.05	156.80	534	
Sep-98	579.47	320.70	569	
Oct-98	663.64	561.20	652	
Nov-98	748.47	958.10	720	
Dec-98	871.31	1252.70	810	
Jan-99	984.21	1350.20	948	
Feb-99	788.10	1066.40	739	
Mar-99	744.40	871.40	729	
Apr-99	714.97	506.40	715	
May-99	630.60	372.20	605	
Jun-99	546.93	140.20	543	
Jul-99	526.49	99.40	522	
Aug-99	546.96	127.80	553	
Sep-99	624.58	292.50	624	
Oct-99	628.26	519.80	631	
Nov-99	766.42	939.90	744	
Dec-99	796.79	1013.00	819	
Jan-00	1138.54	1344.80	1,105	
Feb-00	893.65	956.00	883	
Mar-00	654.03	750.10	681	
Apr-00	703.14	590.90	674	
May-00	635.13	373.80	609	
Jun-00	558.33	158.00	548	
Jul-00	546.81	84.30	548	
Aug-00	588.65	216.90	563	
Sep-00	603.23	314.80	595	
Oct-00	663.78	575.80	647	
Nov-00	757.62	858.40	763	
Dec-00	971.14	1222.80	920	
Jan-01	931.65	1043.40	1,003	
Feb-01	812.83	1031.00	776	
Mar-01	726.99	844.90	721	
Apr-01	677.15	535.80	667	
May-01	651.81	366.60	628	
Jun-01	563.50	155.50	554	
Jul-01	537.78	120.30	526	
Aug-01	554.77	120.60	563	
Sep-01	547.25	299.60	544	
Oct-01	651.57	577.00	635	
Nov-01	792.98	975.00	758	
Dec-01	901.19	1275.40	832	
Jan-02	966.51	1246.30	967	
Feb-02	816.76	970.30	801	
Mar-02	725.43	991.60	668	
Apr-02	741.47	694.80	676	
May-02	641.83	365.90	618	
Jun-02	544.30	147.80	538	
Jul-02	542.23	121.60	530	
Aug-02	610.46	181.50	597	
Sep-02	557.53	331.00	543	
Oct-02	681.82	514.80	686	
Nov-02	762.41	821.90	781	
Dec-02	828.11	1117.90	813	

Yukon Electrical Company Limited
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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-03	947.50	1177.50	972	
Feb-03	770.27	964.70	756	
Mar-03	703.62	899.50	679	
Apr-03	773.76	554.40	757	
May-03	602.98	341.60	588	
Jun-03	555.94	179.90	538	
Jul-03	563.40	56.60	574	
Aug-03	548.69	163.00	542	
Sep-03	609.35	330.20	595	
Oct-03	649.46	526.10	650	
Nov-03	795.50	963.90	765	
Dec-03	968.04	1095.50	961	
Jan-04	971.82	1365.60	931	
Feb-04	807.08	881.20	822	
Mar-04	749.76	809.90	756	
Apr-04	746.11	497.40	749	
May-04	588.46	292.30	590	
Jun-04	605.37	74.10	625	
Jul-04	573.54	35.60	592	
Aug-04	565.49	145.70	565	
Sep-04	646.39	370.70	618	
Oct-04	650.27	565.00	637	
Nov-04	779.25	875.50	779	
Dec-04	897.31	1070.70	899	
Jan-05	1053.13	1330.30	1,024	
Feb-05	807.32	941.80	801	
Mar-05	746.25	726.90	782	
Apr-05	713.95	464.80	728	
May-05	627.27	256.90	642	
Jun-05	584.49	126.60	586	
Jul-05	550.97	136.90	534	
Aug-05	565.02	162.20	559	
Sep-05	689.66	297.30	687	
Oct-05	625.84	541.70	621	
Nov-05	735.46	758.40	776	
Dec-05	894.50	1061.00	900	
Jan-06	918.47	1185.20	940	
Feb-06	910.68	1016.70	879	
Mar-06	916.12	960.50	870	
Apr-06	725.57	528.20	718	
May-06	646.43	371.10	621	
Jun-06	577.76	136.50	575	
Jul-06	587.16	79.20	590	
Aug-06	577.82	171.70	568	
Sep-06	638.51	292.40	638	
Oct-06	664.22	543.30	659	
Nov-06	843.21	1196.20	731	
Dec-06	982.65	1050.00	992	
Jan-07	971.97	1102.40	1,022	
Feb-07	965.40	1017.30	933	
Mar-07	878.64	1001.90	818	
Apr-07	751.49	543.00	739	
May-07	690.20	332.20	678	
Jun-07	604.66	122.60	607	
Jul-07	563.42	88.60	563	
Aug-07	577.38	143.10	578	
Sep-07	586.28	314.70	578	
Oct-07	652.41	553.10	644	
Nov-07	843.28	956.60	815	
Dec-07	804.90	1255.10	742	

Yukon Electrical Company Limited
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Watson Lake Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-08	1123.44	1300.10	1,105	
Feb-08	1032.46	1064.20	984	
Mar-08	834.60	833.30	833	
Apr-08	763.84	554.00	747	
May-08	686.41	295.60	687	
Jun-08	567.13	191.00	546	
Jul-08	590.64	131.50	575	
Aug-08	597.43	154.00	594	
Sep-08	591.51	304.20	587	
Oct-08	660.28	523.50	662	
Nov-08	841.24	879.00	840	
Dec-08	931.20	1386.50	823	
Jan-09	1141.30	1329.30	1,113	
Feb-09	941.96	1089.50	885	
Mar-09	866.43	1054.20	788	
Apr-09	811.02	590.00	782	
May-09	661.27	356.00	641	
Jun-09	570.94	130.60	571	
Jul-09	600.87	89.00	600	
Aug-09	541.21	134.40	545	
Sep-09	622.45	279.40	626	
Oct-09	665.14	606.90	638	
Nov-09	780.80	996.50	738	
Dec-09	964.62	1273.66	896	
Jan-10	1092.76	1141.42	1,130	
Feb-10	861.27	965.80	847	
Mar-10	780.53	763.50	803	
Apr-10	758.96	502.70	760	
May-10	647.75	277.70	655	
Jun-10	582.47	142.70	578	
Jul-10	570.69	70.80	576	
Aug-10	528.80	119.60	537	
Sep-10	610.07	319.65	600	
Oct-10	735.74	516.80	740	
Nov-10	745.44	904.20	735	
Dec-10	912.11	1292.10	837	8797.87
Jan-11	1147.75	1201.00	1,164	
Feb-11	886.24	1004.60	858	
Mar-11	972.16	1032.90	901	
Apr-11	828.25	587.50	800	
May-11	682.17	271.10	691	
Jun-11	614.29	143.10	610	
Jul-11	546.69	104.40	541	
Aug-11	566.02	195.10	548	
Sep-11	642.19	292.40	641	
Nov-11	668.43	511.90	674	
Nov-11	794.53	1059.10	730	
Dec-11	924.66	1006.30	949	9107.89
Jan-12	1124.22	1273.00	1,115	
Feb-12	934.55	935.50	931	
Mar-12	865.63	909.00	837	
Apr-12	778.65	512.60	776	
May-12	710.36	340.20	696	
Jun-12	645.11	149.70	638	
Jul-12	588.63	77.80	592	
Aug-12	572.48	134.00	576	
Sep-12	564.38	259.40	575	
Oct-12	690.01	714.50	625	
Nov-12	773.48	1112.80	691	
Dec-12	1002.41	1356.20	905	8957.12
2013-F				8,954.3
2014-F				8,954.3
2015-F				8,954.3

Yukon Electrical Company Limited
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Keno City Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-98	384.70	1165.70	
Feb-98	458.92	719.10	
Mar-98	239.70	756.60	
Apr-98	289.27	458.60	
May-98	254.35	270.60	
Jun-98	244.49	119.50	
Jul-98	214.42	111.60	
Aug-98	299.18	189.20	
Sep-98	300.37	327.80	
Oct-98	363.74	557.70	
Nov-98	314.71	792.30	
Dec-98	244.83	1051.80	
Jan-99	359.97	1183.10	
Feb-99	300.66	976.40	
Mar-99	274.38	734.00	
Apr-99	328.53	508.80	
May-99	218.89	391.90	
Jun-99	207.66	153.90	
Jul-99	289.26	108.60	
Aug-99	310.03	145.70	
Sep-99	337.63	311.20	
Oct-99	369.92	499.80	
Nov-99	409.03	792.50	
Dec-99	270.84	844.00	
Jan-00	271.49	1082.90	
Feb-00	236.71	735.20	
Mar-00	230.17	659.20	
Apr-00	199.83	515.60	
May-00	256.57	382.00	
Jun-00	256.84	172.50	
Jul-00	250.86	142.10	
Aug-00	295.08	219.90	
Sep-00	283.24	354.20	
Oct-00	366.74	539.20	
Nov-00	283.16	691.20	
Dec-00	244.49	977.80	
Jan-01	275.53	722.70	
Feb-01	236.92	864.10	
Mar-01	287.54	765.30	
Apr-01	258.05	506.80	
May-01	273.66	390.40	
Jun-01	188.31	167.30	
Jul-01	290.95	139.60	
Aug-01	204.74	139.60	
Sep-01	243.29	309.00	
Oct-01	253.00	573.40	
Nov-01	235.97	818.00	
Dec-01	263.24	1094.60	
Jan-02	219.70	935.60	
Feb-02	190.70	824.60	
Mar-02	173.05	921.10	
Apr-02	199.70	653.30	
May-02	230.89	361.60	
Jun-02	210.37	175.60	
Jul-02	235.82	130.90	
Aug-02	264.55	182.80	
Sep-02	239.92	314.40	
Oct-02	250.49	444.30	
Nov-02	220.55	582.60	
Dec-02	220.37	845.20	

Yukon Electrical Company Limited
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Keno City Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-03	255.84	989.10	
Feb-03	204.08	756.60	
Mar-03	184.76	834.50	
Apr-03	177.39	514.30	
May-03	139.16	363.70	
Jun-03	157.24	192.80	
Jul-03	168.50	84.40	
Aug-03	167.61	180.60	
Sep-03	186.87	359.20	
Oct-03	166.74	466.70	
Nov-03	200.23	874.60	
Dec-03	239.89	911.60	
Jan-04	260.29	1257.90	
Feb-04	213.87	697.20	
Mar-04	192.89	753.50	
Apr-04	187.61	466.60	
May-04	187.61	272.50	
Jun-04	167.87	83.70	
Jul-04	156.95	74.20	
Aug-04	173.85	101.70	
Sep-04	222.10	367.50	
Oct-04	157.53	540.50	
Nov-04	274.74	719.80	
Dec-04	190.90	899.50	
Jan-05	246.31	1165.80	
Feb-05	250.95	795.20	
Mar-05	130.28	613.70	
Apr-05	114.58	453.30	
May-05	112.39	256.60	
Jun-05	119.93	154.40	
Jul-05	142.17	132.60	
Aug-05	202.78	150.80	
Sep-05	217.61	299.30	
Oct-05	156.34	534.60	
Nov-05	196.85	762.60	
Dec-05	194.88	794.40	
Jan-06	308.63	1096.20	
Feb-06	214.13	821.30	
Mar-06	296.58	906.30	
Apr-06	207.55	519.10	
May-06	165.68	346.90	
Jun-06	118.28	173.10	
Jul-06	147.02	118.40	
Aug-06	188.20	201.60	
Sep-06	223.71	295.70	
Oct-06	282.66	520.50	
Nov-06	326.76	1162.20	
Dec-06	336.86	824.30	
Jan-07	301.98	912.00	
Feb-07	247.56	998.80	
Mar-07	313.05	954.20	
Apr-07	232.98	511.90	
May-07	183.27	322.10	
Jun-07	159.59	140.50	
Jul-07	189.00	102.30	
Aug-07	218.21	154.20	
Sep-07	251.95	308.40	
Oct-07	327.39	543.70	
Nov-07	273.73	724.60	
Dec-07	223.00	1069.50	

Yukon Electrical Company Limited
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Keno City

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	260.59	1113.80	
Feb-08	308.00	954.60	
Mar-08	233.90	734.70	
Apr-08	304.18	517.30	
May-08	213.00	307.90	
Jun-08	144.85	225.60	
Jul-08	173.07	173.40	
Aug-08	276.17	187.70	
Sep-08	419.12	318.70	
Oct-08	397.65	563.00	
Nov-08	412.73	782.50	
Dec-08	576.50	1186.20	
Jan-09	659.73	1137.90	
Feb-09	294.60	955.40	
Mar-09	568.74	868.50	
Apr-09	323.17	515.20	
May-09	247.26	331.20	
Jun-09	177.57	144.10	
Jul-09	186.95	62.50	
Aug-09	180.45	158.30	
Sep-09	251.31	306.10	
Oct-09	295.00	541.80	
Nov-09	360.00	781.50	
Dec-09	383.54	943.40	
Jan-10	396.90	991.10	
Feb-10	332.03	679.20	
Mar-10	417.27	656.00	
Apr-10	343.62	461.20	
May-10	368.00	292.00	
Jun-10	127.73	171.90	
Jul-10	184.69	117.30	
Aug-10	200.71	146.20	
Sep-10	427.00	332.40	
Oct-10	445.68	520.40	
Nov-10	572.14	717.60	
Dec-10	574.70	1162.50	4390.45
Jan-11	588.16	1010.20	
Feb-11	431.76	905.60	
Mar-11	608.84	901.70	
Apr-11	341.70	511.20	
May-11	342.41	296.20	
Jun-11	229.43	161.00	
Jul-11	335.75	127.80	
Aug-11	140.25	217.90	
Sep-11	343.23	328.50	
Nov-11	447.10	513.30	
Nov-11	471.67	936.25	
Dec-11	640.79	775.10	4921.08
Jan-12	359.21	1118.10	
Feb-12	405.82	707.50	
Mar-12	467.28	756.20	
Apr-12	396.59	450.60	
May-12	381.95	350.80	
Jun-12	293.30	200.00	
Jul-12	198.71	140.10	
Aug-12	220.54	157.90	
Sep-12	332.27	287.15	
Oct-12	458.27	631.40	
Nov-12	566.32	969.60	
Dec-12	480.71	1196.80	4560.95
2013-F			4,624.2
2014-F			4,624.2
2015-F			4,624.2

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Stewart Crossing Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Annual UPC (kWh)
Jan-98	570.00	1409.70	
Feb-98	418.18	942.00	
Mar-98	376.09	843.40	
Apr-98	296.58	500.10	
May-98	387.67	211.00	
Jun-98	274.58	89.00	
Jul-98	350.92	65.70	
Aug-98	347.67	156.80	
Sep-98	343.92	320.70	
Oct-98	403.31	561.20	
Nov-98	454.86	958.10	
Dec-98	587.07	1252.70	
Jan-99	1042.80	1350.20	
Feb-99	719.20	1066.40	
Mar-99	511.07	871.40	
Apr-99	510.33	506.40	
May-99	419.27	372.20	
Jun-99	373.13	140.20	
Jul-99	437.13	99.40	
Aug-99	350.67	127.80	
Sep-99	460.07	292.50	
Oct-99	364.87	519.80	
Nov-99	472.67	939.90	
Dec-99	493.00	1013.00	
Jan-00	880.87	1344.80	
Feb-00	432.40	956.00	
Mar-00	421.80	750.10	
Apr-00	473.80	590.90	
May-00	336.87	373.80	
Jun-00	348.40	158.00	
Jul-00	335.07	84.30	
Aug-00	336.67	216.90	
Sep-00	495.75	314.80	
Oct-00	462.19	575.80	
Nov-00	689.63	858.40	
Dec-00	505.06	1222.80	
Jan-01	589.41	1043.40	
Feb-01	469.00	1031.00	
Mar-01	659.65	844.90	
Apr-01	393.75	535.80	
May-01	536.25	366.60	
Jun-01	284.31	155.50	
Jul-01	302.75	120.30	
Aug-01	310.13	120.60	
Sep-01	486.20	299.60	
Oct-01	449.13	577.00	
Nov-01	749.47	975.00	
Dec-01	606.47	1275.40	
Jan-02	605.94	1246.30	
Feb-02	673.69	970.30	
Mar-02	482.06	991.60	
Apr-02	531.94	694.80	
May-02	647.00	365.90	
Jun-02	482.81	147.80	
Jul-02	469.19	121.60	
Aug-02	569.31	181.50	
Sep-02	503.93	331.00	
Oct-02	667.60	514.80	
Nov-02	634.07	821.90	
Dec-02	842.20	1117.90	

Yukon Electrical Company Limited
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Stewart Crossing Residential monthly	UPC (kWh)	(Watson Lake) MHDD	Annual UPC (kWh)
Jan-03	1071.73	1177.50	
Feb-03	853.33	964.70	
Mar-03	783.20	899.50	
Apr-03	760.60	554.40	
May-03	693.53	341.60	
Jun-03	535.40	179.90	
Jul-03	700.93	56.60	
Aug-03	534.20	163.00	
Sep-03	631.67	330.20	
Oct-03	726.13	526.10	
Nov-03	708.53	963.90	
Dec-03	950.60	1095.50	
Jan-04	1042.00	1365.60	
Feb-04	683.07	881.20	
Mar-04	704.87	809.90	
Apr-04	835.33	497.40	
May-04	640.53	292.30	
Jun-04	651.93	74.10	
Jul-04	729.67	35.60	
Aug-04	598.13	145.70	
Sep-04	605.60	370.70	
Oct-04	837.20	565.00	
Nov-04	850.33	875.50	
Dec-04	663.27	1070.70	
Jan-05	1209.73	1330.30	
Feb-05	891.20	941.80	
Mar-05	716.13	726.90	
Apr-05	899.67	464.80	
May-05	598.80	256.90	
Jun-05	710.60	126.60	
Jul-05	617.40	136.90	
Aug-05	664.07	162.20	
Sep-05	731.60	297.30	
Oct-05	682.13	541.70	
Nov-05	720.27	758.40	
Dec-05	829.80	1061.00	
Jan-06	1086.00	1185.20	
Feb-06	947.62	1016.70	
Mar-06	990.60	960.50	
Apr-06	633.33	528.20	
May-06	632.43	371.10	
Jun-06	831.31	136.50	
Jul-06	561.29	79.20	
Aug-06	817.07	171.70	
Sep-06	940.93	292.40	
Oct-06	821.71	543.30	
Nov-06	888.57	1196.20	
Dec-06	1078.14	1050.00	
Jan-07	1226.93	1102.40	
Feb-07	1030.27	1017.30	
Mar-07	1290.67	1001.90	
Apr-07	693.38	543.00	
May-07	610.25	332.20	
Jun-07	624.94	122.60	
Jul-07	540.75	88.60	
Aug-07	635.69	143.10	
Sep-07	629.63	314.70	
Oct-07	626.19	553.10	
Nov-07	783.25	956.60	
Dec-07	577.63	1255.10	

Yukon Electrical Company Limited
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Stewart Crossing

Residential		(Watson Lake)	Annual
monthly	UPC (kWh)	MHDD	UPC (kWh)
Jan-08	1085.56	1300.10	
Feb-08	873.31	1064.20	
Mar-08	897.88	833.30	
Apr-08	422.19	554.00	
May-08	547.94	295.60	
Jun-08	532.81	191.00	
Jul-08	300.06	131.50	
Aug-08	641.31	154.00	
Sep-08	467.19	304.20	
Oct-08	707.38	523.50	
Nov-08	624.38	879.00	
Dec-08	724.44	1386.50	
Jan-09	1134.44	1329.30	
Feb-09	978.07	1089.50	
Mar-09	671.81	1054.20	
Apr-09	842.37	590.00	
May-09	542.81	356.00	
Jun-09	490.81	130.60	
Jul-09	629.67	89.00	
Aug-09	618.31	134.40	
Sep-09	641.93	279.40	
Oct-09	621.40	606.90	
Nov-09	682.31	996.50	
Dec-09	711.63	1273.66	
Jan-10	1036.07	1141.42	
Feb-10	667.33	965.80	
Mar-10	700.20	763.50	
Apr-10	662.79	502.70	
May-10	603.20	277.70	
Jun-10	412.60	142.70	
Jul-10	492.53	70.80	
Aug-10	446.07	119.60	
Sep-10	544.86	319.65	
Oct-10	312.47	516.80	
Nov-10	785.87	904.20	
Dec-10	817.27	1292.10	7481.24
Jan-11	1152.57	1201.00	
Feb-11	846.53	1004.60	
Mar-11	845.87	1032.90	
Apr-11	790.93	587.50	
May-11	880.31	271.10	
Jun-11	343.00	143.10	
Jul-11	718.36	104.40	
Aug-11	524.40	195.10	
Sep-11	602.80	292.40	
Nov-11	558.20	511.90	
Nov-11	671.00	1059.10	
Dec-11	807.25	1006.30	8741.22
Jan-12	1280.50	1273.00	
Feb-12	775.50	935.50	
Mar-12	850.29	909.00	
Apr-12	431.71	512.60	
May-12	570.36	340.20	
Jun-12	625.69	149.70	
Jul-12	466.57	77.80	
Aug-12	603.57	134.00	
Sep-12	443.14	259.40	
Oct-12	516.07	714.50	
Nov-12	1002.92	1112.80	
Dec-12	1001.85	1356.20	8568.18
2013-F		1,218	8,263.5
2014-F		1,218	8,263.5
2015-F		1,218	8,263.5

Yukon Electrical Company Limited
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Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-98	1148.33	1165.70	
Feb-98	1390.67	719.10	
Mar-98	1251.00	756.60	
Apr-98	1103.67	458.60	
May-98	945.67	270.60	
Jun-98	861.00	119.50	
Jul-98	625.67	111.60	
Aug-98	1008.33	189.20	
Sep-98	1095.00	327.80	
Oct-98	935.33	557.70	
Nov-98	1137.00	792.30	
Dec-98	931.67	1051.80	
Jan-99	974.67	1183.10	
Feb-99	2270.33	976.40	
Mar-99	1260.67	734.00	
Apr-99	970.33	508.80	
May-99	1263.00	391.90	
Jun-99	830.00	153.90	
Jul-99	897.00	108.60	
Aug-99	817.00	145.70	
Sep-99	989.67	311.20	
Oct-99	1007.67	499.80	
Nov-99	1168.33	792.50	
Dec-99	1039.67	844.00	
Jan-00	1437.67	1082.90	
Feb-00	1334.00	735.20	
Mar-00	1228.33	659.20	
Apr-00	1005.33	515.60	
May-00	1066.67	382.00	
Jun-00	909.67	172.50	
Jul-00	840.00	142.10	
Aug-00	979.67	219.90	
Sep-00	857.67	354.20	
Oct-00	1044.67	539.20	
Nov-00	1111.33	691.20	
Dec-00	1285.33	977.80	
Jan-01	1344.67	722.70	
Feb-01	1051.67	864.10	
Mar-01	1105.00	765.30	
Apr-01	1138.33	506.80	
May-01	995.33	390.40	
Jun-01	852.67	167.30	
Jul-01	910.00	139.60	
Aug-01	1008.67	139.60	
Sep-01	997.33	309.00	
Oct-01	1231.33	573.40	
Nov-01	1093.33	818.00	
Dec-01	1126.33	1094.60	
Jan-02	1300.33	935.60	
Feb-02	1052.00	824.60	
Mar-02	1169.67	921.10	
Apr-02	1142.00	653.30	
May-02	1029.33	361.60	
Jun-02	810.67	175.60	
Jul-02	878.67	130.90	
Aug-02	1053.67	182.80	
Sep-02	1013.67	314.40	
Oct-02	1040.00	444.30	
Nov-02	1074.67	582.60	
Dec-02	1034.00	845.20	

Yukon Electrical Company Limited
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Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-03	1562.00	989.10	
Feb-03	1149.67	756.60	
Mar-03	1183.33	834.50	
Apr-03	1727.33	514.30	
May-03	1079.33	363.70	
Jun-03	940.00	192.80	
Jul-03	713.33	84.40	
Aug-03	995.33	180.60	
Sep-03	979.00	359.20	
Oct-03	1003.67	466.70	
Nov-03	1087.00	874.60	
Dec-03	1379.67	911.60	
Jan-04	1503.00	1257.90	
Feb-04	1325.33	697.20	
Mar-04	660.33	753.50	
Apr-04	1102.67	466.60	
May-04	915.00	272.50	
Jun-04	964.67	83.70	
Jul-04	938.33	74.20	
Aug-04	936.33	101.70	
Sep-04	970.67	367.50	
Oct-04	1082.67	540.50	
Nov-04	1215.00	719.80	
Dec-04	1083.00	899.50	
Jan-05	1430.67	1165.80	
Feb-05	1177.33	795.20	
Mar-05	891.67	613.70	
Apr-05	991.67	453.30	
May-05	659.33	256.60	
Jun-05	1585.00	154.40	
Jul-05	904.67	132.60	
Aug-05	932.67	150.80	
Sep-05	894.00	299.30	
Oct-05	1050.67	534.60	
Nov-05	1142.33	762.60	
Dec-05	1240.00	794.40	
Jan-06	1113.33	1096.20	
Feb-06	1596.33	821.30	
Mar-06	1869.67	906.30	
Apr-06	1351.67	519.10	
May-06	1412.67	346.90	
Jun-06	979.00	173.10	
Jul-06	871.00	118.40	
Aug-06	911.67	201.60	
Sep-06	1007.33	295.70	
Oct-06	1077.00	520.50	
Nov-06	1236.00	1162.20	
Dec-06	1497.67	824.30	
Jan-07	1829.67	912.00	
Feb-07	1563.67	998.80	
Mar-07	1426.00	954.20	
Apr-07	1210.00	511.90	
May-07	1262.33	322.10	
Jun-07	1116.00	140.50	
Jul-07	1491.67	102.30	
Aug-07	639.67	154.20	
Sep-07	879.33	308.40	
Oct-07	979.33	543.70	
Nov-07	1180.00	724.60	
Dec-07	1136.00	1069.50	

Yukon Electrical Company Limited
2013 - 2015 General Rate Application

Swift River

Residential monthly	UPC (kWh)	(Whitehorse) MHDD	Annual UPC (kWh)
Jan-08	1438.67	1113.80	
Feb-08	1381.33	954.60	
Mar-08	1053.33	734.70	
Apr-08	1539.00	517.30	
May-08	666.67	307.90	
Jun-08	711.00	225.60	
Jul-08	798.33	173.40	
Aug-08	711.67	187.70	
Sep-08	791.67	318.70	
Oct-08	851.67	563.00	
Nov-08	1001.67	782.50	
Dec-08	1205.33	1186.20	
Jan-09	1811.67	1137.90	
Feb-09	1290.33	955.40	
Mar-09	1636.33	868.50	
Apr-09	1408.00	515.20	
May-09	1376.00	331.20	
Jun-09	1203.33	144.10	
Jul-09	1127.67	62.50	
Aug-09	1108.00	158.30	
Sep-09	1143.33	306.10	
Oct-09	820.00	541.80	
Nov-09	820.00	781.50	
Dec-09	833.33	943.40	
Jan-10	1014.50	991.10	
Feb-10	860.00	679.20	
Mar-10	809.50	656.00	
Apr-10	780.00	461.20	
May-10	464.25	292.00	
Jun-10	309.50	171.90	
Jul-10	123.00	117.30	
Aug-10	525.00	146.20	
Sep-10	567.00	332.40	
Oct-10	451.50	520.40	
Nov-10	1050.00	717.60	
Dec-10	1556.50	1162.50	8510.75
Jan-11	1613.00	1010.20	
Feb-11	1036.00	905.60	
Mar-11	1043.50	901.70	
Apr-11	1853.50	511.20	
May-11	751.00	296.20	
Jun-11	564.50	161.00	
Jul-11	530.50	127.80	
Aug-11	654.50	217.90	
Sep-11	640.50	328.50	
Nov-11	833.00	513.30	
Nov-11	1137.50	936.25	
Dec-11	1126.00	775.10	11783.50
Jan-12	1425.50	1118.10	
Feb-12	1153.50	707.50	
Mar-12	1031.00	756.20	
Apr-12	1014.00	450.60	
May-12	-1357.00	350.80	
Jun-12	869.50	200.00	
Jul-12	743.50	140.10	
Aug-12	774.00	157.90	
Sep-12	804.00	287.15	
Oct-12	671.50	631.40	
Nov-12	1030.50	969.60	
Dec-12	892.50	1196.80	9052.50
2013-F		1,045	9,782.3
2014-F		1,045	9,782.3
2015-F		1,045	9,782.3

Whitehorse
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	1,119.6	1,085.4	1,020.1	1,556.4	1,185.7	1,165.7	1,183.1	1,082.9	722.7	935.6	989.1	1,257.9	1,165.8	1,096.2	912.0	1,113.8	1,137.9	991.1	1,010.2	1,118.1	**1,092.5**
FEB	841.7	1,124.5	840.1	835.8	656.5	719.1	976.4	735.2	864.1	824.6	756.6	697.2	795.2	821.3	998.8	954.6	955.4	679.2	905.6	707.5	**834.5**
MAR	693.4	653.9	880.0	805.8	855.4	756.6	734.0	659.2	765.3	921.1	834.5	753.5	613.7	906.3	954.2	734.7	868.5	656.0	901.7	756.2	**785.2**
APR	417.3	430.8	439.9	526.0	484.0	458.6	508.8	515.6	506.8	653.3	514.3	466.6	453.3	519.1	511.9	517.3	515.2	461.2	511.2	450.6	**493.1**
MAY	244.1	320.9	250.7	357.3	331.1	270.6	391.9	382.0	390.4	361.6	363.7	272.5	256.6	346.9	322.1	307.9	331.2	292.0	296.2	350.8	**322.0**
JUN	132.5	166.2	139.0	193.6	148.9	119.5	153.9	172.5	167.3	175.6	192.8	83.7	154.4	173.1	140.5	225.6	144.1	171.9	161.0	200.0	**160.8**
JUL	96.8	83.7	96.6	124.9	92.8	111.6	108.6	142.1	139.6	130.9	84.4	74.2	132.6	118.4	102.3	173.4	62.5	117.3	127.8	140.1	**113.0**
AUG	158.0	69.6	198.3	227.3	130.0	189.2	145.7	219.9	139.6	182.8	180.6	101.7	150.8	201.6	154.2	187.7	158.3	146.2	217.9	157.9	**165.9**
SEP	279.2	334.9	226.5	362.6	282.1	327.8	311.2	354.2	309.0	314.4	359.2	367.5	299.3	295.7	308.4	318.7	306.1	332.4	328.5	287.2	**315.2**
OCT	478.7	507.0	524.9	679.9	641.0	557.7	499.8	539.2	573.4	444.3	466.7	540.5	534.6	520.5	543.7	563.0	541.8	520.4	513.3	631.4	**541.1**
NOV	732.2	935.9	894.4	975.0	694.0	792.3	792.5	691.2	818.0	582.6	874.6	719.8	762.6	1,162.2	724.6	782.5	781.5	717.6	936.3	969.6	**817.0**
DEC	825.6	1,028.9	1,048.6	1,155.8	762.0	1,051.8	844.0	977.8	1,094.6	845.2	911.6	899.5	794.4	824.3	1,069.5	1,186.2	943.4	1,162.5	775.1	1,196.8	**969.9**
TOTAL	**6,019.1**	**6,741.7**	**6,559.1**	**7,800.4**	**6,263.5**	**6,520.5**	**6,649.9**	**6,471.8**	**6,490.8**	**6,372.0**	**6,528.1**	**6,234.6**	**6,113.3**	**6,985.6**	**6,742.2**	**7,065.4**	**6,745.9**	**6,247.8**	**6,684.8**	**6,966.2**	**6,610.1**

Watson Lake
Heating Degree Day (HDD)
Degree Days Below 18.0 ºC

MONTH	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	20-year "Normal" HDD (1993-12)
JAN	930.6	1,266.0	938.7	1,605.2	1,406.6	1,409.7	1,350.2	1,344.8	1,043.4	1,246.3	1,177.5	1,365.6	1,330.3	1,185.2	1,102.4	1,300.1	1,329.3	1,141.4	1,201.0	1,273.0	**1,247.4**
FEB	752.4	119.4	941.9	947.3	884.8	942.0	1,066.4	956.0	1,031.0	970.3	964.7	881.2	941.8	1,016.7	1,017.3	1,064.2	1,089.5	965.8	1,004.6	935.5	**924.6**
MAR	573.0	24.3	855.6	874.3	943.9	843.4	871.4	750.1	844.9	991.6	899.5	809.9	726.9	960.5	1,001.9	833.3	1,054.2	763.5	1,032.9	909.0	**828.2**
APR	347.3	50.1	492.7	547.7	527.9	500.1	506.4	590.9	535.8	694.8	554.4	497.4	464.8	528.2	543.0	554.0	590.0	502.7	587.5	512.6	**506.4**
MAY	190.5	21.8	242.5	366.4	311.8	211.0	372.2	373.8	366.6	365.9	341.6	292.3	256.9	371.1	332.2	295.6	356.0	277.7	271.1	340.2	**297.9**
JUN	99.2	0.8	97.0	163.9	142.6	89.0	140.2	158.0	155.5	147.8	179.9	74.1	126.6	136.5	122.6	191.0	130.6	142.7	143.1	149.7	**129.5**
JUL	83.2	1.2	113.0	103.3	84.1	65.7	99.4	84.3	120.3	121.6	56.6	35.6	136.9	79.2	88.6	131.5	89.0	70.8	104.4	77.8	**87.3**
AUG	66.0	2.3	189.9	185.1	109.6	156.8	127.8	216.9	120.6	181.5	163.0	145.7	162.2	171.7	143.1	154.0	134.4	119.6	195.1	134.0	**144.0**
SEP	298.4	38.8	224.9	354.7	271.1	320.7	292.5	314.8	299.6	331.0	330.2	370.7	297.3	292.4	314.7	304.2	279.4	319.7	292.4	259.4	**290.3**
OCT	248.2	89.8	552.7	662.2	659.7	561.2	519.8	575.8	577.0	514.8	526.1	565.0	541.7	543.3	553.1	523.5	606.9	516.8	511.9	714.5	**528.2**
NOV	127.3	59.4	1,000.2	1,121.2	935.8	958.1	939.9	858.4	975.0	821.9	963.9	875.5	758.4	1,196.2	956.6	879.0	996.5	904.2	1,059.1	1,112.8	**875.0**
DEC	22.1	122.5	1,295.4	1,361.1	983.7	1,252.7	1,013.0	1,222.8	1,275.4	1,117.9	1,095.5	1,070.7	1,061.0	1,050.0	1,255.1	1,386.5	1,273.7	1,292.1	1,006.3	1,356.2	**1,075.7**
TOTAL	**3,738.2**	**1,796.4**	**6,944.5**	**8,292.4**	**7,261.6**	**7,310.4**	**7,299.2**	**7,446.6**	**7,345.1**	**7,505.4**	**7,252.9**	**6,983.7**	**6,804.8**	**7,531.0**	**7,430.6**	**7,616.9**	**7,929.5**	**7,017.0**	**7,409.4**	**7,774.7**	**6,934.5**

Residential Regression Results (YECL 2013-15 GRA)

Residential (Whitehorse+Takini)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.886842745
R Square	0.786490054
Adjusted R Square	0.78529056
Standard Error	93.0809603
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5680895.965	5680895.965	655.6848146	1.39905E-61
Residual	178	1542203.6	8664.06517		
Total	179	7223099.565			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	587.5320683	13.46646697	43.62926591	5.58402E-97	560.9576003	614.1065363	560.9576003	614.1065363
WH-HDD	0.538334518	0.021023483	25.60634325	1.39905E-61	0.496847179	0.579821856	0.496847179	0.579821856

Residential (Carmacks)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.848334198
R Square	0.719670911
Adjusted R Square	0.718096029
Standard Error	137.0322957
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	8580876.545	8580876.545	456.9679975	4.88748E-51
Residual	178	3342457.313	18777.85007		
Total	179	11923333.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	523.0507986	19.82511653	26.38323956	2.06292E-63	483.9282934	562.1733039	483.9282934	562.1733039
WH-HDD	0.66162154	0.030950434	21.37680981	4.88748E-51	0.600544547	0.722698534	0.600544547	0.722698534

Residential (Carcross)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.73085291
R Square	0.534145976
Adjusted R Square	0.531528819
Standard Error	100.3552824
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2055467.372	2055467.372	204.0939414	2.42352E-31
Residual	178	1792670.521	10071.1827		
Total	179	3848137.893			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	419.1099542	14.51887788	28.86655275	4.6941E-69	390.4586787	447.7612298	390.4586787	447.7612298
WH-HDD	0.323816596	0.022666478	14.28614509	2.42352E-31	0.279087002	0.36854619	0.279087002	0.36854619

Residential (Haines Junction)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.826511766
R Square	0.683121699
Adjusted R Square	0.681341483
Standard Error	70.97827216
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1933198.401	1933198.401	383.7298477	2.73648E-46
Residual	178	896748.8911	5037.915119		
Total	179	2829947.292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	493.5031661	10.26876554	48.0586653	7.1519E-104	473.2389809	513.7673514	473.2389809	513.7673514
WH-HDD	0.31403787	0.016031318	19.58902365	2.73648E-46	0.282401974	0.345673766	0.282401974	0.345673766

Residential (Teslin)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.774809495
R Square	0.600329753
Adjusted R Square	0.598084415
Standard Error	80.08503489
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1714789.401	1714789.401	267.3671534	2.73398E-37
Residual	178	1141623.081	6413.612813		
Total	179	2856412.482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	401.3105811	11.58628439	34.63669349	5.10981E-81	378.4464294	424.1747328	378.4464294	424.1747328
WH-HDD	0.295766652	0.018088193	16.35136549	2.73398E-37	0.260071758	0.331461545	0.260071758	0.331461545

Residential (Ross River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.816954541
R Square	0.667414722
Adjusted R Square	0.665546265
Standard Error	99.84467893
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3560923.245	3560923.245	357.2010799	2.05162E-44
Residual	178	1774474.864	9968.959911		
Total	179	5335398.109			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	420.6644462	14.44500644	29.12179014	1.28614E-69	392.1589471	449.1699452	392.1589471	449.1699452
WH-HDD	0.426211453	0.022551152	18.89976402	2.05162E-44	0.381709441	0.470713465	0.381709441	0.470713465

Residential (Pelly Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.814590942
R Square	0.663558403
Adjusted R Square	0.661668282
Standard Error	106.1935622
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3959003.162	3959003.162	351.0665651	5.74021E-44
Residual	178	2007318.933	11277.07266		
Total	179	5966322.096			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	526.6014045	15.3635297	34.27606902	2.58572E-80	496.2833092	556.9194997	496.2833092	556.9194997
WH-HDD	0.449403793	0.023985126	18.7367704	5.74021E-44	0.402072005	0.496735581	0.402072005	0.496735581

Residential (Old Crow)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.700799321
R Square	0.491119688
Adjusted R Square	0.48826081
Standard Error	91.97982219
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1453372.136	1453372.136	171.7875549	6.55924E-28
Residual	178	1505931.209	8460.28769		
Total	179	2959303.345			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	431.2915805	13.30716006	32.41049018	1.39504E-76	405.0314857	457.5516753	405.0314857	457.5516753
WH-HDD	0.272290334	0.020774777	13.10677515	6.55924E-28	0.231293786	0.313286881	0.231293786	0.313286881

Residential (Destruction Bay)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.709031239
R Square	0.502725298
Adjusted R Square	0.49993162
Standard Error	72.69183708
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	950879.8973	950879.8973	179.9510466	8.32101E-29
Residual	178	940570.3656	5284.103178		
Total	179	1891450.263			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	383.8946	10.51667516	36.50341902	1.40822E-84	363.1411947	404.6480054	363.1411947	404.6480054
WH-HDD	0.220245296	0.016418348	13.41458336	8.32101E-29	0.187845643	0.25264495	0.187845643	0.25264495

Residential (Beaver Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.840637508
R Square	0.706671419
Adjusted R Square	0.705023506
Standard Error	87.03187359
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3248177.952	3248177.952	428.8280135	2.78648E-49
Residual	178	1348269.37	7574.547021		
Total	179	4596447.322			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	483.8810515	12.59131671	38.4297419	4.15449E-88	459.0335882	508.7285147	459.0335882	508.7285147
WH-HDD	0.407064957	0.019657222	20.70816297	2.78648E-49	0.368273771	0.445856142	0.368273771	0.445856142

Residential (Tagish)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.77755681
R Square	0.604594592
Adjusted R Square	0.602373213
Standard Error	63.68762658
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1103956.052	1103956.052	272.1708788	1.04861E-37
Residual	178	721988.2526	4056.113779		
Total	179	1825944.304			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	234.2954311	9.213993033	25.42821883	3.71752E-61	216.1127137	252.4781485	216.1127137	252.4781485
WH-HDD	0.237312001	0.014384636	16.49760221	1.04861E-37	0.208925636	0.265698366	0.208925636	0.265698366

Residential (Marsh Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.873151604
R Square	0.762393723
Adjusted R Square	0.761058856
Standard Error	88.06938915
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4429873.997	4429873.997	571.1384587	1.93035E-57
Residual	178	1380606.68	7756.217305		
Total	179	5810480.677			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	386.6155856	12.74141904	30.3432125	2.9027E-72	361.4719133	411.7592579	361.4719133	411.7592579
WH-HDD	0.475378456	0.019891558	23.89850327	1.93035E-57	0.436124837	0.514632075	0.436124837	0.514632075

Residential (Deep Creek)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.752248092
R Square	0.565877192
Adjusted R Square	0.5634383
Standard Error	105.7520673
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2594820.496	2594820.496	232.0222255	4.42027E-34
Residual	178	1990662.952	11183.49973		
Total	179	4585483.448			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	248.7081064	15.29965652	16.25579673	5.11914E-37	218.5160572	278.9001555	218.5160572	278.9001555
WH-HDD	0.363829131	0.023885409	15.23227578	4.42027E-34	0.316694123	0.410964139	0.316694123	0.410964139

Residential (Lower Post BC)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.81614908
R Square	0.666099321
Adjusted R Square	0.664223475
Standard Error	102.4652481
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3728162.932	3728162.932	355.0926572	2.91803E-44
Residual	178	1868844.62	10499.12708		
Total	179	5597007.552			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	482.5359337	13.76104774	35.06534841	7.55861E-82	455.3801456	509.6917217	455.3801456	509.6917217
WL-HDD	0.350883145	0.018620514	18.84390239	2.91803E-44	0.31413778	0.387628511	0.31413778	0.387628511

Residential (Upper Liard)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.837904563
R Square	0.702084057
Adjusted R Square	0.700410372
Standard Error	81.41823385
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2780729.358	2780729.358	419.483968	1.11237E-48
Residual	178	1179949.327	6628.928803		
Total	179	3960678.685			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	434.4074757	10.93444093	39.72836641	2.07109E-90	412.8296594	455.9852921	412.8296594	455.9852921
WL-HDD	0.303036141	0.014795742	20.48130777	1.11237E-48	0.273838507	0.332233774	0.273838507	0.332233774

Residential (Watson Lake)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91758524
R Square	0.841962672
Adjusted R Square	0.841074822
Standard Error	62.27248406
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3677439.547	3677439.547	948.3161829	3.18151E-73
Residual	178	690259.4843	3877.862272		
Total	179	4367699.032			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	515.255402	8.36317329	61.61003535	5.5467E-122	498.7516761	531.759128	498.7516761	531.759128
WL-HDD	0.348488007	0.011316477	30.79474278	3.18151E-73	0.326156287	0.370819726	0.326156287	0.370819726

Residential (Keno City)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.45197141
R Square	0.204278155
Adjusted R Square	0.199807808
Standard Error	98.54936507
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	443801.0337	443801.0337	45.69625911	1.90467E-10
Residual	178	1728731.969	9711.977356		
Total	179	2172533.003			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	195.761055	14.2576072	13.73028813	1.00194E-29	167.625366	223.8967439	167.625366	223.8967439
WH-HDD	0.150465857	0.022258589	6.759900821	1.90467E-10	0.106541183	0.194390532	0.106541183	0.194390532

Residential (Stewart Crossing)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.578269149
R Square	0.334395209
Adjusted R Square	0.330655856
Standard Error	179.1744974
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2870886.34	2870886.34	89.4259596	1.88615E-17
Residual	178	5714423.091	32103.50051		
Total	179	8585309.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	462.7767125	24.06307365	19.23182047	2.54602E-45	415.2911039	510.2623212	415.2911039	510.2623212
WL-HDD	0.307909483	0.032560515	9.456529998	1.88615E-17	0.243655187	0.372163779	0.243655187	0.372163779

Residential (Swift River)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.478815384
R Square	0.229264172
Adjusted R Square	0.224934195
Standard Error	309.1635718
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5060894.424	5060894.424	52.9481323	1.05385E-11
Residual	178	17013616.31	95582.11413		
Total	179	22074510.74			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	774.2960938	44.72817013	17.3111507	5.25351E-40	686.0303795	862.5618081	686.0303795	862.5618081
WH-HDD	0.508109656	0.069828406	7.276546729	1.05385E-11	0.370311618	0.645907694	0.370311618	0.645907694

YUB-YECL-58

Reference: Line Losses, YECL Application, Section 3, pages 3-2 and 3-3

The energy component of the purchase power cost is determined by applying Yukon Energy's wholesale rate to the total forecast energy (kWh) purchases. Total forecast purchases are determined by 1 applying a forecast line loss percentage to Yukon Electrical's sales load forecast that was discussed in Section 2. Overall, line losses are determined by using a five-year historical average of 6.2%. This is consistent with the approach approved in Board Order 2009-2.

Request:

Please indicate where the Board, in Board Order 2009-2, approved YECL's five-year historical average approach. Provide a specific reference(s).

Response:

Yukon Electrical stated on page 3-2, Lines 18-21 in its 2008-2009 General Rate Application:

> **Forecast Process**
>
> The energy component of the purchase power cost is determined by applying Yukon Energy's wholesale rate to the total forecast energy (KWh) purchases. Total forecast purchases are determined by applying an estimated line loss percentage to Yukon Electrical's sales load forecast that is discussed in Section 2. Overall line losses are determined based on using a five year historical average of 6.2%.

This process was not challenged in IRs or specifically mentioned in the Board Decision 2009-02 Appendix 1 – Reasons for Decision. However, it forms part of the Revenue Requirement ultimately approved in Board Order 2009-02.

YUB-YECL-59

Reference: Capital Additions, YECL Application, Section 9, page 9-4, Schedule 9.1

A listing of the capital expenditures for 2008-2015 is provided in the following pages. For significant projects greater than $100,000, a description of the project is included. Business cases for all major capital projects ($500,000 or greater) are being filed with this Application as directed in Board Order 2009-2.

With respect to capital expenditure totals, YECL has forecast a total of $63.5 million to be spent over the 2013-2015 test period.

Request:

Considering that the $63.5-million forecast expenditures related to capital is almost double the amount of capital expenditures for any prior three-year period and considering the relatively short construction season, please provide a prioritized list of expenditures that make up the $63.5-million test period total shown in Schedule 9.1.

Response:

Yukon Electrical has prioritized all projects in the test years; please refer to YUB-YECL-59 Attachment 1. Priority 'A' projects include projects that reduce or eliminate hazards, forced projects, planned life extensions, new extensions and system performance projects designed to correct unacceptable conditions or imminent hazards. These are projects that Yukon Electrical believes must be completed in order to safely and reliably deliver electricity to customers. Priority 'B' projects include projects that also fit in to those categories, but are less critical, as well as projects that increase operating efficiency and reduce adverse affects on the system. All projects Yukon Electrical has identified are required and necessary for various reasons.

Yukon Electrical is fully cognizant of the short construction season and various other constraints in completing projects throughout its service areas. Yukon Electrical is confident in its capital forecast and its ability to complete the projects as planned for the test years.

Yukon Electrical Capital Projects 2013-2015 By Priority

Priority	Project Name	2013	2014	2015	Total
A	Carmacks North Main Line Rebuild	100,000			100,000
	Crestview to Mayo Road 5L628 Upgrade to 266 MCM	250,000			250,000
	Destruction Bay Plant Foundation Refurbishment	150,000			150,000
	Downtown Whitehorse 25kV Conversion		450,000	450,000	900,000
	Downtown Whitehorse 4L313 Labert Street to Elliot Street - Replace with Underground Lines	424,000			424,000
	Fish Lake Ditch # 3 Diversion Structure Replacement		1,640,000		1,640,000
	Fish Lake Dyke Upgrade	300,000	1,420,000		1,720,000
	Fish Lake Head Pond # 2 Spillway Upgrade	30,000			30,000
	Fish Lake Unit # 1 Spillway Diversion Structure	20,000	100,000		120,000
	Fish Lake Unit # 1 Turbine and Building Replacement	2,167,000			2,167,000
	Fish Lake Unit # 2 Head Pond Low Level Outlet Pipe		30,000		30,000
	Fish Lake Unit # 2 Penstock Improvements	40,000			40,000
	Fish Lake Unit # 2 Siding Replacement	35,000			35,000
	Fish Lake Unit # 2 Vibration Monitoring	20,000			20,000
	Fish Lake Water Licence Renewal	650,000			650,000
	General Drafting and Mapping	80,000			80,000
	Grey Mountain 4L320 Tie Upgrade			65,000	65,000
	Hillcrest Subdivision Conversion	275,000	250,000		525,000
	Hotsprings Road Main Line Relocation and Upgrade	325,000			325,000
	Jack Hulland School Upgrades	100,000			100,000
	Land Rights	190,000	190,000	190,000	570,000
	Lot 1000 Airport Road	53,000			53,000
	Lot 1037 Range Road Line Upgrade	34,000			34,000
	Lot 11 Marion Crescent	53,000			53,000
	MacDonald Road Pole Change			250,000	250,000
	Marwell Lot 14 Transformer Upgrade		100,000		100,000
	McIntyre Subdivision Replacement Stage 1	475,000	250,000		725,000
	Meters General	600,000	50,000	50,000	700,000
	Miscellaneous New U/G Services	600,000	1,000,000	1,000,000	2,600,000
	Miscellaneous O/H Services - Various Subdivisions	3,625,000	2,900,000	4,300,000	10,825,000
	Miscellaneous Pole Replacements	260,000	260,000	260,000	780,000
	Miscellaneous Street Light Replacements	330,000	450,000	330,000	1,110,000
	New Street Light Installations			483,000	483,000
	Old Alaska Highway Bypass	248,000			248,000
	Old Crow Plant Expansion	300,000	1,650,000		1,950,000
	Old Crow Staff Accomodations		100,000		100,000
	Old Crow Unit # 4 Addition		500,000		500,000
	Right of Way Widening	374,000	389,000	405,000	1,168,000
	Riverdale Lewes Substation 25kV Transformer		100,000		100,000

	Riverdale Line 4L317 Tagish Road			250,000	250,000
	Ross River Replace ABB 5HK Breakers		45,000		45,000
	Service to Proposed City of Whitehorse Municipal Services Building on Robert Service Way	420,000			420,000
	Tagish 5L600 Rebuild	300,000		276,000	576,000
	Takhini/Marwell 4L315 Upgrade to 266 ACSR		250,000	350,000	600,000
	Teslin Area Pole Upgrades	53,000			53,000
	Teslin Sawmill Road Upgrade for New Subdivision	38,000			38,000
	Test and Treat Pole Program	110,000	120,000	130,000	360,000
	Transformers & Regulators	10,000	10,000	10,000	30,000
	Upgrade of S2278			45,000	45,000
	Watson Lake Replace ABB 5HK Breakers		180,000	200,000	380,000
	Watson Lake Underground Subdivision Replacement			100,000	100,000
	Whistle Bend Stage 1 & 2 & 3 Street Lights	75,000	450,000		525,000
	Whistle Bend Subdivision Stage 3		1,200,000		1,200,000
	Whitehorse 5L628 and New 34.5kV Build		1,890,000		1,890,000
	Whitehorse Area Line Clearance Upgrades	65,000	70,000		135,000
	Whitehorse Hotsprings Road 3 Phase Conversion			363,000	363,000
	Whitehorse Safety Code Corrections	30,000			30,000
	Whitehorse Service Complex Pole Storage	150,000			150,000
	Yukon Government Teslin Sawmill Subdivision	75,000			75,000
	Other Projects	53,000	80,000	80,000	213,000
A Total		**13,487,000**	**16,124,000**	**9,587,000**	**39,198,000**
B	500kW Mobile Generator	750,000			750,000
	AMR		1,580,000	2,283,000	3,863,000
	Beaver Creek Programmable Logic Control (PLC) Upgrade	180,000			180,000
	Beaver Creek Unit # 1 Replacement			600,000	600,000
	Beaver Creek Unit # 2 Replacement	600,000			600,000
	Carcross 2MVA Generation Standby Unit			3,000,000	3,000,000
	Communication Equipment		11,000	12,000	23,000
	Deep Creek Subdivision Connection to Whitehorse Distribution			60,000	60,000
	Destruction Bay Programmable Logic Controller Upgrade		300,000		300,000
	Destruction Bay Unit # 2 Replacement		600,000		600,000
	Destruction Bay Unit # 3 Replacement		450,000		450,000
	Display Change to Yukon Electrical Billing Statements	259,000			259,000
	Downtown Office Building Envelope Upgrades	600,000			600,000
	Downtown Office Interior Renovations	100,000			100,000
	Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	250,000	300,000		550,000
	DSM Costs	135,000	522,000	730,000	1,387,000
	E-Post Billing	125,000			125,000
	Field Collection System	55,000			55,000
	Field Collection System - Report Development (ITBS)	43,000			43,000
	Fish Lake Unit # 1 Fiber Communication from Head Pond to Unit	20,000			20,000

	Fish Lake Unit # 2 Building Improvements	20,000			20,000
	Fish Lake Unit # 2 SCADA	50,000			50,000
	Lewes Lake Substation Conversion			146,000	146,000
	McLintock Substation Upgrade			90,000	90,000
	Miscellaneous Tools and Instruments	117,000	167,000	115,000	399,000
	New 250kW Mobile Generator	175,000			175,000
	New Cashier System	25,000			25,000
	Office Furniture	44,000		34,000	78,000
	Old Crow Unit # 3 Replacement			500,000	500,000
	PCB Identification and Transformer Change Outs	175,000	100,000	100,000	375,000
	Pelly Crossing Substation Fence	100,000			100,000
	Replacement of Unit 989 - 1995 Hot Line Bucket Truck			450,000	450,000
	Spirit Lake Substation Upgrade			88,000	88,000
	Stewart Crossing Plant Building Insulation		60,000		60,000
	Stewart Crossing Plant Improvements		120,000		120,000
	Stewart Crossing West Town Conversion			60,000	60,000
	Swift River Unit # 2 Replacement	30,000			30,000
	Takhini/Marwell Completion of Mountain Air Subdivision			300,000	300,000
	Transportation Equipment	424,000	995,000	400,000	1,819,000
	Upper Liard - Replace Liard River Crossing			100,000	100,000
	Watson Lake Bi-Fuel Project	363,000	372,000		735,000
	Watson Lake Power Plant Connection to Town Water Supply		100,000		100,000
	Watson Lake Unit # 1 Major Overhaul			250,000	250,000
	Watson Lake Unit # 2 Replacement			1,350,000	1,350,000
	Watson Lake Unit # 4 Replacement	1,120,000			1,120,000
	Watson Lake Unit # 5 Major Overhaul		200,000		200,000
	Watson Lake Unit # 6 Major Overhaul	250,000			250,000
	Whitehorse Airport Hanger D Area Rebuild			140,000	140,000
	Whitehorse Asset Management - Creat a Pole Database	75,000	75,000		150,000
	Whitehorse Service Complex - Fence Extension	20,000			20,000
	Whitehorse Service Complex - Roof/Insulation, Reception Area, and Lighting Upgrades in Service Bays	70,000			70,000
	Whitehorse Service Complex Operations Department and Meeting Room Renovations	80,000			80,000
	Whitehorse Service Complex Parking Lot Expansion and Improvements	100,000			100,000
	Whitehorse Service Complex Yard Extension			300,000	300,000
	Whitehorse Various Service Complex Renovations		100,000		100,000
	Windows 7 Upgrades	146,000			146,000
	Yukon Electrical Website Improvements	35,000			35,000
	Other Projects	259,000	241,000	125,000	625,000
B Total		**6,795,000**	**6,293,000**	**11,233,000**	**24,321,000**
Grand Total		**20,282,000**	**22,417,000**	**20,820,000**	**63,519,000**

YUB-YECL-60

Reference: Generation plant replacement, YECL Application

Request:

Please provide a comparative listing of all YECL generator sets on a per plant basis. The listing should include peak plant loading and by unit, the total engine hours and the total annual hourly usage for the period from 2008 to 2012, as well as the total forecast hours for each year of the forecast period.

Response:

Please refer to YUB-YECL-60 Attachment 1 for a listing of all Yukon Electrical generator sets.

Peak plant loading for the period 2008-2012 was:

	Peak Load (kW)				
Location	**2008**	**2009**	**2010**	**2011**	**2012**
Beaver Creek	358	352	346	359	355
Destruction Bay	375	381	358	389	415
Old Crow	407	460	450	478	462
Swift River	64	64	56	56	59
Watson Lake	2,950	2,825	2,790	3,205	3,126

CUL #	Location	Unit #	Hours In 2008	Hours In 2009	Hours In 2010	Hours In 2011	Hours In 2012	Hours To Date Dec 2012	Forecasted Hours In 2013	Forecasted Hours In 2014	Forecasted Hours In 2015	
303	Beaver Creek	1	5,495	6,146	4,760	3,927	3,918	**85,237**	4,849	2,424		CUL 303 Scheduled for Replacement 2nd Quarter 2014
TBD	Beaver Creek	1								2,425	4,849	New Unit to be Installed 2nd Quarter 2014 *
378	Beaver Creek	2	3,763	3,288	3,441	5,357	4,923	**99,874**	3,115			CUL 378 Scheduled for Replacement 3rd Quarter 2013
TBD	Beaver Creek	2							1,039	4,154	4,154	New Unit to be Installed 3rd Quarter 2013
354	Beaver Creek	3	177	173	1,056	341	630	**25,691**	475	475	475	
230	Destruction Bay	1	3,505	4,709	4,360							CUL 230 Removed From Service 4th Quarter 2010
467	Destruction Bay	1			241	1,932	2,372	**4,747**	2,152	2,152	2,152	CUL 467 Installed 4th Quarter 2010
372	Destruction Bay	2	5,409	4,155	4,259	4,870	3,080	**93,054**	4,354	4,354	3,265	CUL 372 Scheduled for Replacement 3rd Quarter 2015
TBD	Destruction Bay	2									1,089	New Unit to be Installed 3rd Quarter 2015 *
397	Destruction Bay	3	849	813	381	43						CUL 397 Removed From Service 2nd Quarter 2011
230	Destruction Bay	3				2,207	3,312	**96,444**	3,666	2,749		Installed 2nd Quarter 2011, to be Replaced 3rd Quarter 2014
TBD	Destruction Bay	3								917	3,666	New Unit to be Installed 3rd Quarter 2014
414	Old Crow	1	1,021	1,722	2,274	2,667	2,737	**20,184**	2,084	2,084	2,084	
371	Old Crow	2	6,461	6,195	5,611	5,590	2,008	**123,063**				CUL 371 Removed From Service 2nd Quarter 2012
355	Old Crow	2					3,544	**57,141**	5,881	5,146	2,940	CUL 355 Installed 2nd Quarter 2012
384	Old Crow	3	1,209	1,003	1,015	681	939	**28,879**	969	969	484	CUL 384 Scheduled for Replacement 2nd Quarter 2015
TBD	Old Crow	3									485	New Unit to be Installed 2nd Quarter 2015
TBD	Old Crow	4								735	2,941	New Unit to be Installed 3rd Quarter 2014
422	Watson Lake	1	2,838	3,897	4,589	1,792	6,133	**57,579**	3,849	3,849	3,849	
257	Watson Lake	2	1,422	2,151	4,191	2,688	4,287	**84,524**	2,947	2,947	2,210	CUL 257 Scheduled for Replacement 3rd Quarter 2015
TBD	Watson Lake	2									737	New Unit to be Installed 3rd Quarter 2015
352	Watson Lake	3	2,376	3,312	3,098	2,830	4,023	**70,868**	3,127	3,127	3,127	
258	Watson Lake	4	4,683	5,634	2,768	3,758	74	**143,585**	-			CUL 258 Scheduled for Replacement 3rd Quarter 2013
TBD	Watson Lake	4							1,010	4,040	4,040	New Unit to be Installed 3rd Quarter 2013
415	Watson Lake	5	2,787	3,945	-							CUL 415 Removed from Service 2010
466	Watson Lake	5			124	4,520	3,695	**8,339**	4,107	4,107	4,107	CUL 466 Installed 4th Quarter 2010
423	Watson Lake	6	3,745	3,907	5,723	4,683	6,114	**64,820**	4,834	4,834	4,834	
412	Swift River	1	5,507	8,720	7,252							CUL 412 Removed From Service 4th Quarter 2010
460	Swift River	1			850	6,836	65	**7,751**	5,845	5,845	5,845	CUL 460 Installed 4th Quarter 2010
413	Swift River	2	3,362	30	530	1,938	8,902	**26,265**	1,476			CUL 413 Removed From Service 2nd Quarter 2013
544	Swift River	2							1,476	2,952	2,952	CUL 544 Installed 2nd Quarter 2013
375	Pelly Crossing	1	1,015	54	15	390	28	**32,840**	53	53	53	
355	Pelly Crossing	2	5,170	241	73	627						CUL 355 Removed From Service 3rd Quarter 2011
470	Pelly Crossing	2				90	54	**1,745**	53	53	53	CUL 470 Installed 3rd Quarter 2011
405	Pelly Crossing	3	6,274	266	31	1,021	54	**80,528**	53	53	53	
310	Carmacks	1	110	203	16	26	17	**2,024**	74	74	74	
265	Ross River	1	75	109	18	21	22	**9,876**	49	49	49	
416	Haines Junction	1	76	18	61	50	18	**1,025**	44	44	44	
376	Teslin	1	80	35	20	20	17	**1,103**	34	34	34	
186	Stewart Crossing	3	152	7	36	95	57	**41,767**	69	69	69	

* During the interrogatory response process, it has come to Yukon Electrical's attention that it mistakenly identified the replacement of Beaver Creek #1 and Destruction Bay #2 as years 2015 and 2014, respectively. The correct years should have been 2014 and 2015. As the forecast costs for the two replacements are each$ 600,000, there is no impact to Yukon Electrical's overall capital forecast for 2014 or 2015.

YUB-YECL-61

Reference: 2008-2015 capital expenditures, YECL Application

A listing of the capital expenditures for 2008-2015 is provided in the following pages. For significant projects greater than $100,000, a description of the project is included. Business cases for all major capital projects ($500,000 or greater) are being filed with this Application as directed in Board Order 2009-2.

Request:

For each of the capital expenditures for 2008-2015 provided on pages 9-5 to 9-67, please provide a continuity table. Please retain the following headings: Generation Plants, Distribution New Extensions (gross and net of customer contributions), Distribution Improvements, Street and Sentinel lighting, Transformers & Regulators, Meters, General Property & Equipment, CIS Billing System Conversion. Moreover, please ensure that projects that are ongoing from year to year, such as replacement of transportation equipment, replacement of meters and new installations, new underground line extensions, and pole replacement are aligned as one project over the years.

Response:

Please refer to YUB-YECL-61 Attachment 1 for a continuity table of capital expenditures from 2008 to 2015.

Please refer to YUB-YECL-61 Attachment 2 for a breakdown of actual as well as forecast capital projects with a total project cost greater than $100,000 for the period 2008-2015.

Below is a table that presents the information that Yukon Electrical has provided to allow for the testing of the reasonability of its capital forecast.

	2008-2015		2013-2015	
Type	$$	%	$$	%
Business Case/Extended Write-Ups	40,810,000	34.41%	34,236,000	53.90%
Project Description Write-Up	58,033,000	48.93%	25,251,000	39.75%
Listed Projects	15,466,000	13.04%	3,194,000	5.03%
Other Small Projects	4,289,000	3.62%	839,000	1.32%
Total	118,598,000	100.00%	63,520,000	100.00%
Total of Projects detailed in YUB-YECL-61 Attachment 2	104,178,000	87.84%	61,229,000	96.39%

The Other Small Projects of $4,289,000 from 2008-2015 are comprised of approximately 800 projects, each under $25,000. This equates to an average project cost of approximately $5,361 per project. Yukon Electrical has not listed these projects due to their immaterial nature on an individual and consolidated basis.

The Yukon Electrical Company Limited
Continuity of Capital Additions 2008-2015

Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
Generation	Fish Lake Unit # 2 Penstock Replacement	Bus Case 1, Pg 9-18, 9-26			486,000	70,000					**556,000**
	Old Crow Unit # 4 Addition	Bus Case 10, Pg 9-54							500,000		**500,000**
	Beaver Creek Unit # 1 Replacement	Bus Case 11, Pg 9-61								600,000	**600,000**
	Carcross 2MVA Generation Standby Unit	Bus Case 12, Pg 9-61								3,000,000	**3,000,000**
	Watson Lake Unit # 2 Replacement	Bus Case 13, Pg 9-61								1,350,000	**1,350,000**
	Destruction Bay Unit # 2 Replacement	Bus Case 14, Pg 9-54							600,000		**600,000**
	Old Crow Unit # 3 Replacement	Bus Case 15, Pg 9-61								500,000	**500,000**
	Fish Lake Unit # 1 Turbine and Building Replacement	Bus Case 2, Pg 9-26, 9-34, 9-44				717,000	1,024,000	2,167,000			**3,908,000**
	Watson Lake Unit # 4 Replacmenet	Bus Case 3, Pg 9-34, 9-44					354,000	1,120,000			**1,474,000**
	500kW Mobile Generator	Bus Case 4, Pg 9-44						750,000			**750,000**
	Beaver Creek Unit # 2 Replacement	Bus Case 5, Pg 9-44						600,000			**600,000**
	Watson Lake Bi-Fuel Project	Bus Case 6, Pg 9-35, 9-44, 9-54					90,000	363,000	372,000		**825,000**
	Fish Lake Dyke Upgrade	Bus Case 7, Pg 9-44, 9-54						300,000	1,420,000		**1,720,000**
	Old Crow Plant Expansion	Bus Case 8, Pg 9-44, 9-54						300,000	1,650,000		**1,950,000**
	Fish Lake Ditch # 3 Diversion Structure Replacement	Bus Case 9, Pg 9-54							1,640,000		**1,640,000**
	Destruction Bay Compton Protection Relay Replacement and Battery Charger Upgrade	Pg 9-5	65,000								**65,000**
	Fish Lake Unit # 1 Generator EOL Rebuild	Pg 9-5	463,000								**463,000**
	Haines Junction Plant Upgrades	Pg 9-5	100,000								**100,000**
	Pelly Crossing Tie into Transmission Grid	Pg 9-5	92,500								**92,500**
	Watson Lake Generator Upgrades and Fresh Air Intakes	Pg 9-5	76,500								**76,500**
	Fish Lake Control Room Monitor Upgrade	Pg 9-12		52,000							**52,000**
	Fish Lake Incremental Purchase Power	Pg 9-12		69,000							**69,000**
	Haines Junction Plant Controls Upgrade	Pg 9-12		324,000							**324,000**
	Fish Lake Unit # 2 New Wheel, Shaft and Bearing Pedestal	Pg 9-12, 9-18, 9-26		153,000	294,000	18,000					**465,000**
	Fish Lake Unit # 1 Replacement Wheel	Pg 9-12, 9-19		80,000	45,000						**125,000**
	Swift River Unit # 1 Replacement	Pg 9-12, 9-19		32,000	25,000						**57,000**
	Destruction Bay Unit # 1 Replacement	Pg 9-18			275,000						**275,000**
	Fish Lake Unit # 1 Spillway	Pg 9-18, 9-26			212,000	26,000					**238,000**
	Watson Lake Unit # 5 Replacement	Pg 9-18, 9-26			232,000	32,000					**264,000**
	Purchase Unit for Pelly Crossing Power Plant	Pg 9-19			101,000						**101,000**
	Fish Lake Ditch # 3 Drop Box Concrete Upgrade	Pg 9-19, 9-26			32,000	57,000					**89,000**
	Pelly Crossing Plant Automation	Pg 9-19, 9-27, 9-35			25,000	10,000	53,000				**88,000**
	Fish Lake Dyke Widening	Pg 9-26				52,000					**52,000**
	Fish Lake Unit # 1 Tailrace Reconstruction	Pg 9-26				173,000					**173,000**
	Haines Junction Plant Relocation on to Foundation	Pg 9-26				14,000					**14,000**
	High Voltage Switching Cubicle and Termination for Old Crow Plant	Pg 9-26				20,000					**20,000**
	Hobo for Franklin Lake Water Monitoring	Pg 9-26				36,000					**36,000**
	Hobo Water Monitor for Fish Lake at Range Road	Pg 9-26				22,000					**22,000**
	Louise Lake Control Structure Gate Replacement	Pg 9-26				68,000					**68,000**
	Purchase of Used Spare Generator	Pg 9-26				50,000					**50,000**
	Ross River Substation Improvements	Pg 9-26				52,000					**52,000**
	Stewart Crossing Radio Replacement and Programmable Logic Controller (PLC) Upgrade for Remote Control	Pg 9-26				30,000					**30,000**
	Teslin Plant Combustible Air Intake and Louver Improvements	Pg 9-26				19,000					**19,000**
	Watson Lake Protection Upgrade	Pg 9-26				48,000					**48,000**
	Teslin Programmable Logic Controller (PLC) Replacement	Pg 9-26, 9-35				33,000	31,000				**64,000**
	Ross River Unit Protection Relay	Pg 9-27				11,000					**11,000**
	Beaver Creek Control Room Separation from Plant	Pg 9-34					137,000				**137,000**
	Fish Lake Unit # 2 Step-Up Transformer	Pg 9-34					172,000				**172,000**
	Fish Lake Unit # 2 Turbine Inlet Valve (TIV) Replacement	Pg 9-34					171,000				**171,000**
	Watson Lake Unit # 3 Major Overhaul	Pg 9-34					247,000				**247,000**
	Beaver Creek Programmable Logic Control (PLC) Upgrade	Pg 9-34, 9-45					206,000	180,000			**386,000**
	Carmacks Fuel System Upgrade	Pg 9-35					100,000				**100,000**
	Destruction Bay Fuel System Upgrade	Pg 9-35					21,000				**21,000**
	Haines Junction Fuel System Upgrade	Pg 9-35					20,000				**20,000**
	Old Crow Generator Change Out	Pg 9-35					90,000				**90,000**
	Ross River Fuel System Upgrade	Pg 9-35					37,000				**37,000**
	Teslin Fuel System Upgrade	Pg 9-35					41,000				**41,000**
	Water Pressue Monitor (Hobo) for Louise Lake	Pg 9-35					37,000				**37,000**
	Swift River Unit # 2 Replacement	Pg 9-35, 9-45					53,000	30,000			**83,000**
	Watson Lake Unit # 6 Major Overhaul	Pg 9-44						250,000			**250,000**
	Destruction Bay Plant Foundation Refurbishment	Pg 9-45						150,000			**150,000**
	Fish Lake Head Pond # 2 Spillway Upgrade	Pg 9-45						30,000			**30,000**
	Fish Lake Unit # 1 Fiber Communication from Head Pond to Unit	Pg 9-45						20,000			**20,000**
	Fish Lake Unit # 2 Building Improvements	Pg 9-45						20,000			**20,000**
	Fish Lake Unit # 2 Penstock Improvements	Pg 9-45						40,000			**40,000**
	Fish Lake Unit # 2 SCADA	Pg 9-45						50,000			**50,000**
	Fish Lake Unit # 2 Siding Replacement	Pg 9-45						35,000			**35,000**
	Fish Lake Unit # 2 Vibration Monitoring	Pg 9-45						20,000			**20,000**
	New 250kW Mobile Generator	Pg 9-45						175,000			**175,000**
	Fish Lake Unit # 1 Spillway Diversion Structure	Pg 9-45, 9-55						20,000	100,000		**120,000**
	Destruction Bay Programmable Logic Controller Upgrade	Pg 9-54							300,000		**300,000**
	Destruction Bay Unit # 3 Replacement	Pg 9-54							450,000		**450,000**
	Fish Lake Unit # 2 Head Pond Low Level Outlet Pipe	Pg 9-55							30,000		**30,000**
	Ross River Replace ABB 5HK Breakers	Pg 9-55							45,000		**45,000**
	Stewart Crossing Plant Building Insulation	Pg 9-55							60,000		**60,000**
	Stewart Crossing Plant Improvements	Pg 9-55							120,000		**120,000**
	Watson Lake Unit # 5 Major Overhaul	Pg 9-55							200,000		**200,000**
	Watson Lake Replace ABB 5HK Breakers	Pg 9-55, 9-61							180,000	200,000	**380,000**
	Watson Lake Unit # 1 Major Overhaul	Pg 9-61								250,000	**250,000**
	Other Projects Less Than $20,000	Pg 9-5, 9-12, 9-19, 9-27, 9-35, 9-45, 9-55	56,000	69,000	83,000	94,000	231,000	76,000	92,000		**701,000**
Generation Total			**853,000**	**779,000**	**1,810,000**	**1,652,000**	**3,115,000**	**6,696,000**	**7,759,000**	**5,900,000**	**28,564,000**

The Yukon Electrical Company Limited
Continuity of Capital Additions 2008-2015

Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
New Extensions	Whistle Bend Subdivision Stage 1 & 2	Bus Case 16, Pg 9-27, 9-36				1,242,000	683,000				**1,925,000**
	Whistle Bend Stage 3	Bus Case 17, Pg 9-56							1,200,000		**1,200,000**
	Little Atlin Feeder Tap	Pg 9-6	178,000								**178,000**
	Mountain Air Subdivision	Pg 9-6	317,000								**317,000**
	Stan McCowan Subdivision	Pg 9-6	126,000								**126,000**
	Yukon Government Whitehorse Copper Phase II	Pg 9-6	262,000								**262,000**
	Hamilton Boulevard Main Infrastructure Extension	Pg 9-6, 9-13	266,000	100,000							**366,000**
	Miscellaneous O/H Services - Various Subdivisions	Pg 9-6, 9-13, 9-19, 9-27, 9-36, 9-46, 9-56, 9-62	1,304,000	969,000	1,022,000	1,274,000	992,000	3,625,000	2,900,000	4,300,000	**16,386,000**
	4th Ave and Strickland Condominiums	Pg 9-7	92,000								**92,000**
	Arkell Subdivision Infill	Pg 9-7	78,000								**78,000**
	Carcross Tagish First Nation Carcross Line Rerouting	Pg 9-7	32,000								**32,000**
	Connection of Minto Landing into Yukon Interconnected System	Pg 9-7	47,000								**47,000**
	Lot 10 Centennial Street	Pg 9-7	28,000								**28,000**
	Lot 16 Marwell Subdivision	Pg 9-7	53,000								**53,000**
	New Customer Connection at Minto Crossing	Pg 9-7	40,000								**40,000**
	Skookum Asphalt Plant	Pg 9-7	61,000								**61,000**
	Whitehorse Cadet Camp Three Phase Service	Pg 9-7	40,000								**40,000**
	Miscellaneous New U/G Services	Pg 9-7, 9-14, 9-20, 9-28, 9-37, 9-46, 9-56, 9-62	95,000	36,000	86,000	216,000	144,000	600,000	1,000,000	1,000,000	**3,177,000**
	Land Rights	Pg 9-7, 9-14, 9-20, 9-28, 9-46, 9-56, 9-62	100,000	56,000	66,000	72,000		190,000	190,000	190,000	**864,000**
	General Drafting and Mapping	Pg 9-7, 9-14, 9-46	46,000	75,000				80,000			**201,000**
	Ingram Subdivision	Pg 9-13		717,000							**717,000**
	New Whitehorse Correctional Centre	Pg 9-13		90,000							**90,000**
	Two City Water Wells in Riverdale	Pg 9-13		107,000							**107,000**
	Yukon Housing 8-Plex	Pg 9-13		88,000							**88,000**
	Takhini North Infill	Pg 9-13, 9-20		341,000	312,000						**653,000**
	35 Unit Condominium Wann Road	Pg 9-14		53,000							**53,000**
	Burns Road Lot Development	Pg 9-14		86,000							**86,000**
	Champagne Aishihik First Nation Subdivision	Pg 9-14		36,000							**36,000**
	City of Whitehorse Public Safety Building	Pg 9-14		61,000							**61,000**
	Lot 1095 Gentain Lane	Pg 9-14		41,000							**41,000**
	Selkirk First Nation Child Care Center	Pg 9-14		36,000							**36,000**
	Ta'an Kwach'an Council Subdivision - Klondike Highway North	Pg 9-14		60,000							**60,000**
	Takhini Lot 1371	Pg 9-14		33,000							**33,000**
	Teslin Seniors 8-Plex	Pg 9-14		40,000							**40,000**
	Watson Lake Line Move	Pg 9-14		35,000							**35,000**
	Whitehorse Lot 1097	Pg 9-14		46,000							**46,000**
	Yukon Government Army Beach Sweage Lagoon	Pg 9-14		47,000							**47,000**
	Yukon Government Carcross Water Front Place	Pg 9-14		35,000							**35,000**
	Yukon Government Carmacks Sewer Treatment Plant	Pg 9-14		32,000							**32,000**
	Yukon Government New Airport Parking Area	Pg 9-14		58,000							**58,000**
	Whitehorse General Hospital Staff Residence	Pg 9-14, 9-21		32,000	30,000						**62,000**
	Northwestel Communication Tower Hotsprings Road	Pg 9-15		27,000							**27,000**
	10 Units on Range Road	Pg 9-20			46,000						**46,000**
	35 Unit Condominium Near Mountain Air Subdivision	Pg 9-20			50,000						**50,000**
	Haines Junction Cultural Centre	Pg 9-20			74,000						**74,000**
	Lower Post Health Center 3 Phase Line	Pg 9-20			733,000						**733,000**
	Main Street Condominium	Pg 9-20			45,000						**45,000**
	Marsh Lake Landfill	Pg 9-20			64,000						**64,000**
	New Country Residential Subdivision in Haines Junction	Pg 9-20			105,000						**105,000**
	Stan McCowan 12-Plex	Pg 9-20			59,000						**59,000**
	Whitehorse Water Front Place Line Relocation	Pg 9-20			73,000						**73,000**
	Yukon College	Pg 9-20			57,000						**57,000**
	Yukon Gardens Subdivision	Pg 9-20			59,000						**59,000**
	Yukon Government Core Library	Pg 9-20			59,000						**59,000**
	Carcross Landfill	Pg 9-21			33,000						**33,000**
	Crestview Booster Station	Pg 9-21			29,000						**29,000**
	Grove Street New Lots	Pg 9-21			35,000						**35,000**
	Little Salmon Carmacks First Nation Healing Centre	Pg 9-21			21,000						**21,000**
	Lot 1018 Main Street	Pg 9-21			42,000						**42,000**

The Yukon Electrical Company Limited
Continuity of Capital Additions 2008-2015

Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
	Lot 1100 Tagish	Pg 9-21			29,000						**29,000**
	Lot 40 Mount Sima	Pg 9-21			22,000						**22,000**
	Yukon Government - Yukon River Crossing Study and Design	Pg 9-21			43,000						**43,000**
	Yukon Housing Seniors Housing - Jeckell Street	Pg 9-21			44,000						**44,000**
	Yukon Government Haines Junction Willow Acres Residential Infill	Pg 9-21, 9-28			37,000	124,000					**161,000**
	25 Wann Road - 65 Units	Pg 9-27				343,000					**343,000**
	Grizzly Valley New Extension Out of Subdivision	Pg 9-27				415,000					**415,000**
	Water Front Place Line Relocation	Pg 9-27, 9-37				385,000	100,000				**485,000**
	Carcross Retail Shops	Pg 9-28				51,000					**51,000**
	Diamond Ranch Extension	Pg 9-28				130,000					**130,000**
	Ingram 6-Plex Subdivision	Pg 9-28				165,000					**165,000**
	Lot 1368 Mayo Road	Pg 9-28				80,000					**80,000**
	Mount Sima T-Bar	Pg 9-28				86,000					**86,000**
	River's Edge Development	Pg 9-28				81,000					**81,000**
	Watson Lake Hospital Upgrade	Pg 9-28				104,000					**104,000**
	Grizzly Valley New Extension In Subdivision	Pg 9-28, 9-36				193,000	272,000				**465,000**
	F.H. Collins Secondary School Transformer	Pg 9-28, 9-38				72,000	48,000				**120,000**
	Falcon Ridge Development Stage 4	Pg 9-28, 9-38				271,000	34,000				**305,000**
	14th Ave Whitehorse	Pg 9-29				34,000					**34,000**
	6-Plex 1204 Centennial	Pg 9-29				44,000					**44,000**
	8-Plex Lot 1127 Hillcrest	Pg 9-29				35,000					**35,000**
	Condominium - 602 Main Street	Pg 9-29				33,000					**33,000**
	Eagle Eye Subdivision	Pg 9-29				45,000					**45,000**
	Kwanlin Dun First Nation Cultural Centre	Pg 9-29				31,000					**31,000**
	Lot 1084 Grizzly Valley	Pg 9-29				37,000					**37,000**
	Lot 1309 Ibex	Pg 9-29				33,000					**33,000**
	Yukon Government Water Treatment Plant	Pg 9-29				34,000					**34,000**
	Yukon Housing Abbeyfield Senior's Residence	Pg 9-29				48,000					**48,000**
	Kulan Area Line Improvements	Pg 9-29, 9-38				34,000	41,000				**75,000**
	Grey Wolf 1583 Wann Road	Pg 9-36					198,000				**198,000**
	Lot 1146 Crestview Development	Pg 9-36					161,000				**161,000**
	Northwestel Fox Point	Pg 9-36					308,000				**308,000**
	Northwestel Minto	Pg 9-36					308,000				**308,000**
	Carcross Tagish First Nation C82B Subdivision	Pg 9-37					86,000				**86,000**
	Daylu Dena 10 Lots Lower Post	Pg 9-37					74,000				**74,000**
	Hidden Haven	Pg 9-37					78,000				**78,000**
	Lot 405 Takhini	Pg 9-37					130,000				**130,000**
	Mah's Point Condominiums	Pg 9-37					193,000				**193,000**
	Yukon Government Ross River Pole Relocation	Pg 9-37					122,000				**122,000**
	Yukon Government Tagish Landfill	Pg 9-37					104,000				**104,000**
	Yukon Government Teslin Pole Moves	Pg 9-37					67,000				**67,000**
	20 Laberge Road Service Upgrade	Pg 9-38					26,000				**26,000**
	Betty's Haven Shelter Lot 6	Pg 9-38					65,000				**65,000**
	City of Whitehorse Marwell Reroute	Pg 9-38					28,000				**28,000**
	City of Whitehorse Ponderosa Communication Tower	Pg 9-38					34,000				**34,000**
	City of Whitehorse Selkirk Street Pump House # 6	Pg 9-38					58,000				**58,000**
	Ingram Subdivision 15 Units	Pg 9-38					60,000				**60,000**
	Liard First Nation Lots 123 and 134 2 Mile Subdivision	Pg 9-38					55,000				**55,000**
	Lot 1014 Alaska Highway South	Pg 9-38					39,000				**39,000**
	Lot 105 Otter Road	Pg 9-38					35,000				**35,000**
	Lot 1395 North Klondike Highway	Pg 9-38					47,000				**47,000**
	Lots 1095/1096 Grizzly Subdivision	Pg 9-38					32,000				**32,000**
	New Hangar Condor Road	Pg 9-38					51,000				**51,000**
	Yukon Government Civil Excavations in Watson Lake	Pg 9-38					62,000				**62,000**
	Yukon Government Mt. Lorne Land Fill	Pg 9-38					27,000				**27,000**
	Yukon Government Yukon River Crossing	Pg 9-38					62,000				**62,000**
	Lot 11 Marion Crescent	Pg 9-46						53,000			**53,000**
	Service to Proposed City of Whitehorse Municipal Services Building on Robert Service Way	Pg 9-46						420,000			**420,000**
	Yukon Government Teslin Sawmill Subdivision	Pg 9-46						75,000			**75,000**
	Lot 1000 Airport Road	Pg 9-47						53,000			**53,000**
	Other Projects Less Than $20,000	Pg 9-7, 9-15, 9-21, 9-29, 9-38, 9-47, 9-56, 9-62	79,000	100,000	122,000	366,000	95,000	53,000	80,000	80,000	**975,000**
New Extensions Total			**3,244,000**	**3,437,000**	**3,397,000**	**6,078,000**	**4,919,000**	**5,149,000**	**5,370,000**	**5,570,000**	**37,164,000**

The Yukon Electrical Company Limited
Continuity of Capital Additions 2008-2015

Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
Distribution Improvements	Hillcrest Subdivision Conversion	Bus Case 18, Pg 9-9, 9-15, 9-22, 9-31, 9-39, 9-47, 9-57	93,000	152,000	226,000	2,000	252,000	275,000	250,000		**1,250,000**
	Whistlebend 34.5kV Substation Distribution Lines	Bus Case 19, Pg 9-21, 9-30			492,000	156,000					**648,000**
	Whistle Bend Substation	Bus Case 20, Pg 9-29, 9-39				1,690,000	423,000				**2,113,000**
	5L628 Crestview to Mayo Road Corner Double Circuit	Bus Case 21, Pg 9-39					628,000				**628,000**
	McIntyre Subdivision Replacement Stage 1	Bus Case 22, Pg 9-47, 9-57						475,000	250,000		**725,000**
	Whitehorse 5L628 and New 34.5kV Build	Bus Case 23, Pg 9-56							1,890,000		**1,890,000**
	Downtown Whitehorse 25kV Conversion	Bus Case 24, Pg 9-56, 9-62							450,000	450,000	**900,000**
	Takhini/Marwell 4L315 Upgrade to 266 ACSR	Bus Case 25, Pg 9-57, Pg 9-63							250,000	350,000	**600,000**
	4L311 Upgrade Distribution Lines Between 1st and 6th Avenue Downtown Whitehorse	Pg 9-8	439,000								**439,000**
	5L628 Squanga Road Rebuild	Pg 9-8	290,000								**290,000**
	9L - Km 129 to Km 132 South Klondike Highway - Distribution Line Rebuild	Pg 9-8	189,000								**189,000**
	Connect Pelly Crossing into Yukon Interconnected System	Pg 9-8	435,000								**435,000**
	Ketza Court Live Front Transformers Replacement	Pg 9-8	346,000								**346,000**
	Right of Way Widening	Pg 9-8, 9-15, 9-21, 9-30, 9-39, 9-47, 9-57, 9-63	268,000	240,000	304,000	331,000	377,000	374,000	389,000	405,000	**2,688,000**
	Beaver Creek Planned Pole Replacements	Pg 9-9	25,000								**25,000**
	Cadet Camp Three Phase Service System Improvement	Pg 9-9	83,000								**83,000**
	Campbell Highway Relocation	Pg 9-9	43,000								**43,000**
	Carmacks Planned Pole Replacements	Pg 9-9	28,000								**28,000**
	Carmacks Upper Bench Rerouting	Pg 9-9	31,000								**31,000**
	Little Atlin Lake Area 3 Phase Pole Upgrades	Pg 9-9	60,000								**60,000**
	McIntyre Subdivision 34.5kV Upgrade	Pg 9-9	47,000								**47,000**
	Morley Bay Line Upgrade	Pg 9-9	46,000								**46,000**
	North Star Clearance Upgrade	Pg 9-9	24,000								**24,000**
	Paddlewheel Line Relocation	Pg 9-9	30,000								**30,000**
	Porter Creek Regulator Upgrade	Pg 9-9	26,000								**26,000**
	System Upgrades Lot 1378/79 Range Road	Pg 9-9	93,000								**93,000**
	Tagish Bridge Conduit Replacement	Pg 9-9	60,000								**60,000**
	9L Reliability Upgrade Squanga Lake Area	Pg 9-9, 9-15	77,000	51,000							**128,000**
	Birch Alley Upgrade	Pg 9-9, 9-15	45,000	32,000							**77,000**
	Echo Lake Road Upgrade	Pg 9-9, 9-15	52,000	75,000							**127,000**
	Miscellaneous Pole Replacements	Pg 9-9, 9-16, 9-23, 9-31, 9-40, 9-48, 9-57, 9-64	92,000	22,000	26,000	70,000	60,000	260,000	260,000	260,000	**1,050,000**
	Test and Treat Pole Program	Pg 9-9, 9-22, 9-40, 9-49, 9-58, 9-64	72,000		57,000		153,000	110,000	120,000	130,000	**642,000**
	Convert Spirit Lake to 14.4kV	Pg 9-10	22,000								**22,000**
	Marwell Subdivision Improvements	Pg 9-10	21,000								**21,000**
	McIntyre Creek Pumphouse Upgrade	Pg 9-10	23,000								**23,000**
	Arkell Subdivision Upgrade	Pg 9-10, 9-15	21,000	197,000							**218,000**
	McDonald Road to Centennial Road Upgrade	Pg 9-10, 9-15	23,000	24,000							**47,000**
	Liard River Crossing	Pg 9-15		29,000							**29,000**
	Robinson Substation Upgrade	Pg 9-15		39,000							**39,000**
	Whitehorse Airport Conversion	Pg 9-15		29,000							**29,000**
	Wickstrom Road Line Relocation for Whitehorse General Hospital Residence and Medical Building	Pg 9-15		83,000							**83,000**
	System Upgrade on Hotsprings River Road	Pg 9-16		22,000							**22,000**
	Watson Lake Hotel Upgrade	Pg 9-16		20,000							**20,000**
	Teslin and Klondike Road Upgrade	Pg 9-16, 9-23		20,000	30,000						**50,000**
	Destruction Bay Distribution Breaker Addition	Pg 9-22			54,000						**54,000**
	Destruction Bay Main Feeder	Pg 9-22			42,000						**42,000**
	Haines Junction Distribution Breaker Addition	Pg 9-22			51,000						**51,000**
	Main Steel Alley 4th - 7th Avenue Upgrade	Pg 9-22			98,000						**98,000**
	Main Street Alley Upgrade	Pg 9-22			44,000						**44,000**
	Mount Sima Subdivision	Pg 9-22			42,000						**42,000**
	North Klondike Grounding Improvements	Pg 9-22			42,000						**42,000**
	Old Crow Pole Change Outs	Pg 9-22			46,000						**46,000**
	Porter Creek Breaker Replacement	Pg 9-22			54,000						**54,000**
	Takhini North Upgrade	Pg 9-22			134,000						**134,000**
	Watson Lake 3-Phase System Protection Upgrade	Pg 9-22			100,000						**100,000**
	4L316 Two Mile Hill Conductor Upgrade	Pg 9-23			38,000						**38,000**
	McIntyre Subdivision Prebuilding Work	Pg 9-23			22,000						**22,000**
	Nordenskiold River Bridge Rerouting	Pg 9-23			42,000						**42,000**
	Pole Removal Wickstrom Road	Pg 9-23			25,000						**25,000**
	Whithorse Copper Rebuild	Pg 9-23			27,000						**27,000**
	System Frequency Upgrades at S150 Substation	Pg 9-23, 9-31			39,000	37,000					**76,000**
	System Upgrade, Extension of 5L628 to Grizzly Valley	Pg 9-29				454,000					**454,000**
	5L626 Double Circuit Line to Whistle Bend Substation	Pg 9-30				200,000					**200,000**
	Hotsprings Road Upgrade	Pg 9-30				190,000					**190,000**
	Laberge Substation Distribution Upgrades	Pg 9-30				416,000					**416,000**
	Upgrade Laberge Substation Transformer to 10 MVA	Pg 9-30				189,000					**189,000**
	PCB Identification and Transformer Change Outs	Pg 9-30, 9-39, 9-48, 9-58, 9-65				239,000	401,000	175,000	100,000	100,000	**1,015,000**
	Carcross Town Pole Replacements	Pg 9-31				27,000					**27,000**
	Centennial Street Upgrades	Pg 9-31				20,000					**20,000**
	Configure Pelly Substation to Yukon Interconnected System	Pg 9-31				23,000					**23,000**
	Line Relocation Eagle Way	Pg 9-31				30,000					**30,000**
	Line Upgrade and Relocation Army Beach	Pg 9-31				92,000					**92,000**
	Line Upgrade and Relocation Lot 56 Paint Mountain	Pg 9-31				69,000					**69,000**
	System Upgrade 113 Copper Road	Pg 9-31				53,000					**53,000**
	Whistle Bend Substation Transformer	Pg 9-31				127,000					**127,000**
	Shipyard's Substation Transformer Failure and Upgrades	Pg 9-39					473,000				**473,000**
	97 Lewes Boulevard Transformer Upgrade	Pg 9-40					70,000				**70,000**
	Breaker Replacement in Services Substation	Pg 9-40					84,000				**84,000**
	Laberge Substation 34.5kV Conductor Upgrade	Pg 9-40					103,000				**103,000**

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Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
	Laberge Substation Upgrade	Pg 9-40					57,000				**57,000**
	Old Crow 3rd Distribution Breaker	Pg 9-40					78,000				**78,000**
	Range Road Line Rerouting	Pg 9-40					56,000				**56,000**
	Regulator to North Klondike Highway	Pg 9-40					154,000				**154,000**
	Whitehorse Elementary School Transformer Upgrade	Pg 9-40					94,000				**94,000**
	CRE Breaker Replacement in Lewes Boulevard	Pg 9-41					30,000				**30,000**
	Marsh Lake Structure Upgrade	Pg 9-41					21,000				**21,000**
	Marsh Lake Substation Upgrade	Pg 9-41					45,000				**45,000**
	Ponderosa Road Vault Addition and Service Upgrade	Pg 9-41					35,000				**35,000**
	Porter Creek Underground Vaults Replacement	Pg 9-41					28,000				**28,000**
	Ross River Recloser for S7580	Pg 9-41					30,000				**30,000**
	System Improvements Lowe Street	Pg 9-41					21,000				**21,000**
	Whitehorse Service Area Line Clearance Upgrades	Pg 9-41					25,000				**25,000**
	Downtown Whitehorse 4L313 Labert Street to Elliot Street - Replace with Underground Lines	Pg 9-47						424,000			**424,000**
	Tagish 5L600 Rebuild	Pg 9-47, 9-63						300,000		276,000	**576,000**
	Crestview to Mayo Road 5L628 Upgrade to 266 MCM	Pg 9-48						250,000			**250,000**
	Old Alaska Highway Bypass	Pg 9-48						248,000			**248,000**
	Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	Pg 9-48, 9-57						250,000	300,000		**550,000**
	Carmacks North Main Line Rebuild	Pg 9-49						100,000			**100,000**
	Hotsprings Road Main Line Relocation and Upgrade	Pg 9-49						325,000			**325,000**
	Jack Hulland School Upgrades	Pg 9-49						100,000			**100,000**
	Lot 1037 Range Road Line Upgrade	Pg 9-49						34,000			**34,000**
	Pelly Crossing Substation Fence	Pg 9-49						100,000			**100,000**
	Teslin Area Pole Upgrades	Pg 9-49						53,000			**53,000**
	Teslin Sawmill Road Upgrade for New Subdivision	Pg 9-49						38,000			**38,000**
	Whitehorse Safety Code Corrections	Pg 9-49						30,000			**30,000**
	Whitehorse Area Line Clearance Upgrades	Pg 9-49, 9-58						65,000	70,000		**135,000**
	Whitehorse Asset Management - Creat a Pole Database	Pg 9-49, 9-58						75,000	75,000		**150,000**
	Marwell Lot 14 Transformer Upgrade	Pg 9-58							100,000		**100,000**
	Riverdale Lewes Substation 25kV Transformer	Pg 9-58							100,000		**100,000**
	Takhini/Marwell Completion of Mountain Air Subdivision	Pg 9-63								300,000	**300,000**
	Whitehorse Hotsprings Road 3 Phase Conversion	Pg 9-63								363,000	**363,000**
	Lewes Lake Substation Conversion	Pg 9-64								146,000	**146,000**
	MacDonald Road Pole Change	Pg 9-64								250,000	**250,000**
	Riverdale Line 4L317 Tagish Road	Pg 9-64								250,000	**250,000**
	Whitehorse Airport Hanger D Area Rebuild	Pg 9-64								140,000	**140,000**
	Deep Creek Subdivision Connection to Whitehorse Distribution	Pg 9-65								60,000	**60,000**
	Grey Mountain 4L320 Tie Upgrade	Pg 9-65								65,000	**65,000**
	McLintock Substation Upgrade	Pg 9-65								90,000	**90,000**
	Spirit Lake Substation Upgrade	Pg 9-65								88,000	**88,000**
	Stewart Crossing West Town Conversion	Pg 9-65								60,000	**60,000**
	Upgrade of S2278	Pg 9-65								45,000	**45,000**
	Upper Liard - Replace Liard River Crossing	Pg 9-65								100,000	**100,000**
	Watson Lake Underground Subdivision Replacement	Pg 9-65								100,000	**100,000**
	Other Projects Less Than $20,000	Pg 9-10, 9-16, 9-23, 9-31, 9-41, 9-49, 9-58, 9-65	291,000	168,000	216,000	211,000	320,000	76,000	34,000	56,000	**1,372,000**
Distribution Improvements Total			**3,395,000**	**1,203,000**	**2,251,000**	**4,626,000**	**4,018,000**	**4,137,000**	**4,638,000**	**4,084,000**	**28,352,000**
Street and Sentinel Lighting	Whistle Bend Stage 1 & 2 Street Lights	Bus Case 26, Pg 9-31, 9-41				257,000	150,000				**407,000**
	Whistle Bend Stage 1 & 2 & 3 Street Lights	Bus Case 26, Pg 9-50, 9-58						75,000	450,000		**525,000**
	4th Ave & Strickland Light Upgrade	Pg 9-10	41,000								**41,000**
	Carmacks High Pressure Sodium Light Upgrade	Pg 9-10	20,000								**20,000**
	Foxhaven Street Lights Relocation	Pg 9-10	82,000								**82,000**
	Quartz Road Street Lights Relocation	Pg 9-10	21,000								**21,000**
	Whitehorse Copper Light Additions	Pg 9-10	131,000								**131,000**
	Hamilton Boulevard Extension	Pg 9-10, 9-16	435,000	41,000							**476,000**
	Pine Street Light Replacement	Pg 9-10, 9-23	25,000		161,000						**186,000**
	Ta'an Kwach'an Council Subdivision	Pg 9-16		54,000							**54,000**
	Ingram Subdivision Street Lights	Pg 9-16, 9-23		113,000	50,000						**163,000**
	Takhini North Subdivision	Pg 9-16, 9-23		86,000	56,000						**142,000**
	Street Light Identification	Pg 9-23			24,000						**24,000**
	Takhini River Lights	Pg 9-23			24,000						**24,000**
	Whistle Bend Way Light Additions	Pg 9-23, 9-32			62,000	143,000					**205,000**
	Black Street Additions and Rebuild	Pg 9-32				20,000					**20,000**
	Boxwood Light Upgrade	Pg 9-32				44,000					**44,000**
	Morley and Peel Street Light Replacement	Pg 9-32				150,000					**150,000**
	Trail Lighting along Whitehorse Waterfront to Shipyards Park	Pg 9-32				100,000					**100,000**
	Wharf Lighting 1st Ave Whitehorse	Pg 9-32				147,000					**147,000**
	Grizzly Valley Street Lights	Pg 9-32, 9-41				27,000	33,000				**60,000**
	Black Street - 6th Avenue Escarpment	Pg 9-41					37,000				**37,000**
	Yukon Government Lights on 8th Street Watson Lake	Pg 9-41					143,000				**143,000**
	Miscellaneous Street Light Replacements	Pg 9-50, 9-59, 9-66						330,000	450,000	330,000	**1,110,000**
	New Street Light Installations	Pg 9-66								483,000	**483,000**
	Other Projects Less Than $20,000	Pg 9-10, 9-16, 9-23, 9-32, 9-41, 9-50, 9-59	84,000	60,000	109,000	157,000	93,000	15,000	45,000		**563,000**
Street and Sentinel Lighting Total			**839,000**	**354,000**	**486,000**	**1,045,000**	**456,000**	**420,000**	**945,000**	**813,000**	**5,358,000**
Meters	AMR	Bus Case 27, Pg 9-59, 9-66							1,580,000	2,283,000	**3,863,000**
	Meters General	Pg 9-11, 9-24, 9-32, 9-42, 9-50, 9-59, 9-66	31,000		460,000	199,000	283,000	600,000	50,000	50,000	**1,673,000**
Meters Total			**31,000**	-	**460,000**	**199,000**	**283,000**	**600,000**	**1,630,000**	**2,333,000**	**5,536,000**

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Appropriation Type	Project Name	Reference	2008	2009	2010	2011	2012	2013	2014	2015	Total
Transformers & Regulators	Transformers & Regulators	Pg 9-16, 9-33, 9-42, 9-50, 9-59, 9-66		80,000		9,000	34,000	10,000	10,000	10,000	**153,000**
Transformers & Regulators Total			-	**80,000**	-	**9,000**	**34,000**	**10,000**	**10,000**	**10,000**	**153,000**
GP&E	Fish Lake Water Licence Renewal	Bus Case 28, Pg 9-33, 9-42, 9-51				491,000	688,000	650,000			**1,829,000**
	Downtown Office Building Envelope Upgrades	Bus Case 29, Pg 9-51						600,000			**600,000**
	DSM Costs	Bus Case 30, Pg 9-33, 9-43, 9-52, 9-60, 9-66				204,000	143,000	135,000	522,000	730,000	**1,734,000**
	Whitehorse Service Complex Pole Relocation	Pg 9-11	51,000								**51,000**
	Oracle Hrxcellence HR Management	Pg 9-11, 9-16, 9-25	138,000	117,000	103,000						**358,000**
	Transportation Equipment	Pg 9-11, 9-17, 9-24, 9-33, 9-42, 9-51, 9-59, 9-67	139,000	100,000	358,000	257,000	421,000	424,000	995,000	400,000	**3,094,000**
	Miscellaneous Tools and Instruments	Pg 9-11, 9-17, 9-24, 9-33, 9-42, 9-52, 9-60, 9-67	45,000	37,000	176,000	67,000	166,000	117,000	167,000	115,000	**890,000**
	Communication Equipment	Pg 9-11, 9-17, 9-33, 9-43, 9-60, 9-67	57,000	47,000		49,000	57,000		11,000	12,000	**233,000**
	Distribution SCADA Equipment	Pg 9-24			138,000						**138,000**
	Credit Card Pre-Authorized Payment Plan System	Pg 9-25			67,000						**67,000**
	Service Complex Engineering Department Renovations	Pg 9-25			86,000						**86,000**
	Service Complex Construction Department Renovations	Pg 9-33				31,000					**31,000**
	Office Furniture	Pg 9-33, 9-43, 9-53, 9-67				72,000	24,000	44,000		34,000	**174,000**
	New Cashier System	Pg 9-33, 9-53				33,000		25,000			**58,000**
	Whitehorse Service Complex HVAC Replacement	Pg 9-43					59,000				**59,000**
	Windows 7 Upgrades	Pg 9-43, 9-51					61,000	146,000			**207,000**
	Downtown Office Interior Renovations	Pg 9-43, 9-52					62,000	100,000			**162,000**
	Display Change to Yukon Electrical Billing Statements	Pg 9-51						259,000			**259,000**
	Whitehorse Service Complex Pole Storage	Pg 9-51						150,000			**150,000**
	E-Post Billing	Pg 9-52						125,000			**125,000**
	Whitehorse Service Complex - Roof/Insulation, Reception Area, and Lighting Upgrades in Service Bays	Pg 9-52						70,000			**70,000**
	Whitehorse Service Complex Operations Department and Meeting Room Renovations	Pg 9-52						80,000			**80,000**
	Whitehorse Service Complex Parking Lot Expansion and Improvements	Pg 9-52						100,000			**100,000**
	Field Collection System	Pg 9-53						55,000			**55,000**
	Field Collection System - Report Development (ITBS)	Pg 9-53						43,000			**43,000**
	Whitehorse Service Complex - Fence Extension	Pg 9-53						20,000			**20,000**
	Yukon Electrical Website Improvements	Pg 9-53						35,000			**35,000**
	Old Crow Staff Accomodations	Pg 9-60							100,000		**100,000**
	Watson Lake Power Plant Connection to Town Water Supply	Pg 9-60							100,000		**100,000**
	Whitehorse Various Service Complex Renovations	Pg 9-60							100,000		**100,000**
	Replacement of Unit 989 - 1995 Hot Line Bucket Truck	Pg 9-67								450,000	**450,000**
	Whitehorse Service Complex Yard Extension	Pg 9-67								300,000	**300,000**
	Other Projects Less Than $20,000	Pg 9-11, 9-17, 9-25, 9-33, 9-43, 9-53, 9-60, 9-67	79,000	99,000	57,000	126,000	85,000	92,000	71,000	69,000	**678,000**
GP&E Total			**509,000**	**400,000**	**985,000**	**1,330,000**	**1,766,000**	**3,270,000**	**2,066,000**	**2,110,000**	**12,436,000**
CIS Billing System Conversion	CIS Billing System Conversion	Pg 9-11	1,035,000								**1,035,000**
CIS Billing System Conversion Total			**1,035,000**								**1,035,000**
Grand Total			**9,906,000**	**6,253,000**	**9,389,000**	**14,939,000**	**14,591,000**	**20,282,000**	**22,418,000**	**20,820,000**	**118,598,000**

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Miscellaneous O/H Services - Various Subdivisions	New Extensions	Annual	Labour	521,600	387,600	408,800	509,600	396,800	1,450,000	1,160,000	1,720,000	6,554,400	
			Contract Services									-	
			Materials	782,400	581,400	613,200	764,400	595,200	2,175,000	1,740,000	2,580,000	9,831,600	
			Other									-	16,386,000
Fish Lake Unit # 1 Turbine and Building Replacement	Generation	2013	Labour				16,000	6,000	21,670			43,670	
			Contract Services				81,000	26,000	130,020			237,020	
			Materials				589,000	413,000	1,256,860			2,258,860	
			Other				31,000	579,000	758,450			1,368,450	3,908,000
Automated Meter Reading	Meters	2015	Labour							220,000	546,000	766,000	
			Contract Services							250,000	-	250,000	
			Materials							909,000	1,457,000	2,366,000	
			Other							201,000	280,000	481,000	3,863,000
Miscellaneous New U/G Services	New Extensions	Annual	Labour	22,000	18,000	49,000	78,000	55,000	234,000	390,000	390,000	1,236,000	
			Contract Services	21,000	10,000	26,500	62,000	37,000	162,000	270,000	270,000	858,500	
			Materials	46,000	4,000	500	60,000	40,000	156,000	260,000	260,000	826,500	
			Other	6,000	4,000	10,000	16,000	12,000	48,000	80,000	80,000	256,000	3,177,000
Transportation Equipment	GP&E	Annual	Labour									-	
			Contract Services									-	
			Materials	139,000	100,000	358,000	257,000	421,000	424,000	995,000	400,000	3,094,000	
			Other									-	3,094,000
Carcross 2MVA Generation Standby Unit	Generation	2015	Labour								450,000	450,000	
			Contract Services									-	
			Materials								2,550,000	2,550,000	
			Other									-	3,000,000
Right of Way Widening	Distribution	Annual	Labour	32,000	29,000	36,000	40,000	45,000	45,000	47,000	49,000	323,000	
			Contract Services	220,000	197,000	249,000	271,000	309,000	307,000	319,000	332,000	2,204,000	
			Materials	-	-	-	-	-	-	-	-	-	
			Other	16,000	14,000	19,000	20,000	23,000	22,000	23,000	24,000	161,000	2,688,000
Whistle Bend Substation	Distribution	2012	Labour				127,000	145,000				272,000	
			Contract Services				469,000	167,000				636,000	
			Materials				984,000	(34,000)				950,000	
			Other				110,000	145,000				255,000	2,113,000
Old Crow Plant Expansion	Generation	2014	Labour						10,000	50,000		60,000	
			Contract Services						290,000	1,600,000		1,890,000	
			Materials									-	
			Other									-	1,950,000
Whistle Bend Subdivision Stage 1 & 2	New Extensions	2012	Labour				23,000	75,000				98,000	
			Contract Services				19,000	314,000				333,000	
			Materials				1,149,000	241,000				1,390,000	
			Other				51,000	53,000				104,000	1,925,000
Whitehorse 5L628 and New 34.5kV Build	Distribution	2014	Labour							56,700		56,700	
			Contract Services							1,171,800		1,171,800	
			Materials							661,500		661,500	
			Other							-		-	1,890,000
Fish Lake Water Licence Renewal	GP&E	2013	Labour				55,000	58,000	65,000			178,000	
			Contract Services				396,000	574,000	533,000			1,503,000	
			Materials				-	-				-	
			Other				40,000	56,000	52,000			148,000	1,829,000
DSM Costs	GP&E	2015	Labour				-	-	48,000	93,000	93,000	234,000	
			Contract Services				195,000	137,000	70,000	-	-	402,000	
			Materials				-	2,000	1,000	-	-	3,000	
			Other				9,000	4,000	16,000	429,000	637,000	1,095,000	1,734,000
Fish Lake Dyke Upgrade	Generation	2014	Labour						5,000	70,000		75,000	
			Contract Services						295,000	1,350,000		1,645,000	
			Materials									-	
			Other									-	1,720,000
Meters	Meters	Annual	Labour	4,000		100,000	61,000	78,000	150,000	13,000	13,000	419,000	
			Contract Services	1,000		-	11,000	1,000	6,000	-	-	19,000	
			Materials	24,000		347,000	115,000	181,000	414,000	35,000	35,000	1,151,000	
			Other	2,000		13,000	12,000	23,000	30,000	2,000	2,000	84,000	1,673,000
Fish Lake Ditch # 3 Diversion Structure Replacement	Generation	2014	Labour							60,000		60,000	
			Contract Services							1,580,000		1,580,000	
			Materials									-	
			Other									-	1,640,000
Watson Lake Unit # 4 Replacement	Generation	2013	Labour					1,000	-			1,000	
			Contract Services					2,000	11,000			13,000	
			Materials					339,000	1,075,000			1,414,000	
			Other					12,000	34,000			46,000	1,474,000
Watson Lake Unit # 2 Replacement	Generation	2015	Labour									-	
			Contract Services								13,500	13,500	
			Materials								1,296,000	1,296,000	
			Other								40,500	40,500	1,350,000
Hillcrest Subdivision Conversion	Distribution	2014	Labour	8,000	5,000	22,000	-	21,000	22,000	20,000		98,000	
			Contract Services	68,000	150,000	61,000	-	120,000	151,000	138,000		688,000	
			Materials	16,000	(3,000)	143,000	2,000	107,000	99,000	90,000		454,000	
			Other	1,000	-	-	-	4,000	3,000	2,000		10,000	1,250,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Whistle Bend Subdivision Stage 3	New Extensions	2014	Labour							12,000		12,000	
			Contract Services							144,000		144,000	
			Materials							984,000		984,000	
			Other							60,000		60,000	1,200,000
Miscellaneous Street Light Replacements	Street Lights	Annual	Labour						32,000	60,000	32,000	124,000	
			Contract Services						100,000	120,000	100,000	320,000	
			Materials						198,000	270,000	198,000	666,000	
			Other									-	1,110,000
Miscellaneous Pole Replacements	Distribution	Annual	Labour	40,000	9,000	6,000	21,000	4,000	78,000	78,000	78,000	314,000	
			Contract Services	19,000	9,000	12,000	13,000	32,000	81,000	81,000	81,000	328,000	
			Materials	22,000	1,000	7,000	23,000	23,000	73,000	73,000	73,000	295,000	
			Other	11,000	3,000	1,000	13,000	1,000	28,000	28,000	28,000	113,000	1,050,000
CIS Billing System Conversion	CIS Billing System Conversion	2008	Labour	104,000								104,000	
			Contract Services	856,000								856,000	
			Materials	-								-	
			Other	75,000								75,000	1,035,000
PCB Identification and Transformer Change Outs	Distribution	Annual	Labour				8,000	7,000	4,000	2,000	2,000	23,000	
			Contract Services				221,000	366,000	161,000	92,000	92,000	932,000	
			Materials				8,000	27,000	10,000	6,000	6,000	57,000	
			Other				2,000	1,000	-	-	-	3,000	1,015,000
Downtown Whitehorse 25kV Conversion	Distribution	2015	Labour							36,000	36,000	72,000	
			Contract Services							247,500	247,500	495,000	
			Materials							166,500	166,500	333,000	
			Other							-	-	-	900,000
Miscellaneous Tools and Instruments	GP&E	Annual	Labour									-	
			Contract Services									-	
			Materials	45,000	37,000	176,000	67,000	166,000	117,000	167,000	115,000	890,000	
			Other									-	890,000
Land Rights	New Extensions	Annual	Labour	55,000	34,000	40,000	30,000	-	103,000	103,000	103,000	468,000	
			Contract Services	32,000	6,000	13,000	27,000	-	51,000	51,000	51,000	231,000	
			Materials	-	-	-	-	-	-	-	-	-	
			Other	13,000	16,000	13,000	15,000	-	36,000	36,000	36,000	165,000	864,000
Watson Lake Bi-Fuel Project	Generation	2014	Labour					15,000	30,000	5,000		50,000	
			Contract Services					17,000	123,000	52,000		192,000	
			Materials					54,000	200,000	300,000		554,000	
			Other					4,000	10,000	15,000		29,000	825,000
Arkell Subdivision Infill	New Extensions	2009	Labour	31,000	34,000							65,000	
			Contract Services	4,000	158,000							162,000	
			Materials	31,000	517,000							548,000	
			Other	12,000	8,000							20,000	795,000
500kW Mobile Generator	Generation	2013	Labour									-	
			Contract Services									-	
			Materials						750,000			750,000	
			Other									-	750,000
Lower Post Health Center 3 Phase Line	New Extensions	2010	Labour			53,000						53,000	
			Contract Services			495,000						495,000	
			Materials			172,000						172,000	
			Other			13,000						13,000	733,000
McIntyre Subdivision Replacement Stage 1	Distribution	2014	Labour						50,000	25,000		75,000	
			Contract Services						125,000	65,000		190,000	
			Materials						300,000	160,000		460,000	
			Other									-	725,000
Takhini North Infill	New Extensions	2010	Labour		44,000	25,000						69,000	
			Contract Services		90,000	83,000						173,000	
			Materials		199,000	202,000						401,000	
			Other		8,000	2,000						10,000	653,000
Whistle Bend 34.5kV Substation Distribution Lines	Distribution	2010	Labour			20,000	5,000					25,000	
			Contract Services			244,000	185,000					429,000	
			Materials			227,000	(35,000)					192,000	
			Other			1,000	1,000					2,000	648,000
Test and Treat Pole Program	Distribution	Annual	Labour	1,000		1,000		1,000	1,000	1,000	1,000	6,000	
			Contract Services	68,000		53,000		138,000	101,000	110,000	120,000	590,000	
			Materials	-		-		-	-	-	-	-	
			Other	3,000		3,000		14,000	8,000	9,000	9,000	46,000	642,000
5L628 Crestview to Mayo Road Corner Double Circuit	Distribution	2012	Labour					20,000				20,000	
			Contract Services					389,000				389,000	
			Materials					218,000				218,000	
			Other					1,000				1,000	628,000
Takhini/Marwell 4L315 Upgrade to 266 ACSR	Distribution	2015	Labour							25,000	35,000	60,000	
			Contract Services							65,000	91,000	156,000	
			Materials							160,000	224,000	384,000	
			Other									-	600,000
Downtown Office Building Envelope Upgrades	GP&E	2013	Labour									-	
			Contract Services						600,000			600,000	
			Materials									-	
			Other									-	600,000
Destruction Bay Unit # 2 Replacement	Generation	2014	Labour							78,000		78,000	
			Contract Services							30,000		30,000	
			Materials							438,000		438,000	
			Other							54,000		54,000	600,000
Beaver Creek Unit # 2 Replacement	Generation	2013	Labour						78,000			78,000	
			Contract Services						30,000			30,000	
			Materials						438,000			438,000	
			Other						54,000			54,000	600,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Beaver Creek Unit # 1 Replacement	Generation	2015	Labour								78,000	78,000	
			Contract Services								30,000	30,000	
			Materials								438,000	438,000	
			Other								54,000	54,000	600,000
Tagish 5L600 Rebuild	Distribution	2015	Labour						30,000		28,000	58,000	
			Contract Services						178,000		72,000	250,000	
			Materials						92,000		176,000	268,000	
			Other									-	576,000
Fish Lake Unit # 2 Penstock Replacement	Generation	2010	Labour			1,000	-					1,000	
			Contract Services			468,000	52,000					520,000	
			Materials			-	-					-	
			Other			17,000	18,000					35,000	556,000
Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	Distribution	2014	Labour						25,000	30,000		55,000	
			Contract Services						125,000	178,000		303,000	
			Materials						100,000	92,000		192,000	
			Other									-	550,000
Whistle Bend Stage 1 & 2 & 3 Street Lights	Street Lights	2014	Labour						1,500	9,000		10,500	
			Contract Services						9,000	54,000		63,000	
			Materials						61,500	369,000		430,500	
			Other						3,000	18,000		21,000	525,000
Old Crow Unit # 4 Addition	Generation	2014	Labour							30,000		30,000	
			Contract Services							50,000		50,000	
			Materials							420,000		420,000	
			Other									-	500,000
Old Crow Unit # 3 Replacement	Generation	2015	Labour								10,000	10,000	
			Contract Services								20,000	20,000	
			Materials								470,000	470,000	
			Other									-	500,000
Water Front Place Line Relocation	New Extensions	2011	Labour				15,000	2,000				17,000	
			Contract Services				189,000	26,000				215,000	
			Materials				180,000	71,000				251,000	
			Other				1,000	1,000				2,000	485,000
New Street Light Installations	Street Lights	2015	Labour								193,000	193,000	
			Contract Services									-	
			Materials								290,000	290,000	
			Other									-	483,000
Hamilton Boulevard Extension	Street Lights	2009	Labour	5,000	2,000							7,000	
			Contract Services	9,000	32,000							41,000	
			Materials	401,000	(14,000)							387,000	
			Other	20,000	21,000							41,000	476,000
Shipyard's Substation Transformer Failure and Upgrades	Distribution	2012	Labour					62,000				62,000	
			Contract Services					30,000				30,000	
			Materials					371,000				371,000	
			Other					10,000				10,000	473,000
Grizzly Valley New Extension In Subdivision	New Extensions	2011	Labour				6,000	6,000				12,000	
			Contract Services				138,000	204,000				342,000	
			Materials				48,000	61,000				109,000	
			Other				1,000	1,000				2,000	465,000
Fish Lake Unit #2 New Wheel, Shaft and Bearing Pedestal	Generation	2011	Labour		-	21,000						21,000	
			Contract Services		-	144,000						144,000	
			Materials		141,000	97,000						238,000	
			Other		12,000	32,000	18,000					62,000	465,000
Fish Lake Unit # 1 Generator EOL Rebuild	Generation	2008	Labour	38,000								38,000	
			Contract Services	330,000								330,000	
			Materials	70,000								70,000	
			Other	25,000								25,000	463,000
System Upgrade, Extension of 5L628 to Grizzly Valley	Distribution	2011	Labour				76,000					76,000	
			Contract Services				291,000					291,000	
			Materials				73,000					73,000	
			Other				14,000					14,000	454,000
Replacement of Unit 989 - 1995 Hot Line Bucket Truck	GP&E	2015	Labour									-	
			Contract Services									-	
			Materials								450,000	450,000	
			Other									-	450,000
Destruction Bay Unit # 3 Replacement	Generation	2014	Labour							58,500		58,500	
			Contract Services							22,500		22,500	
			Materials							328,500		328,500	
			Other							40,500		40,500	450,000
4L311 Upgrade Distribution Lines Between 1st and 6th Avenue Downtown Whitehorse	Distribution	2008	Labour	17,000								17,000	
			Contract Services	201,000								201,000	
			Materials	219,000								219,000	
			Other	2,000								2,000	439,000
Connect Pelly Crossing into Yukon Interconnected System	Distribution	2008	Labour	30,000								30,000	
			Contract Services	169,000								169,000	
			Materials	230,000								230,000	
			Other	6,000								6,000	435,000
Downtown Whitehorse 4L313 Labert Street to Elliot Street - Replace with Underground Lines	Distribution	2013	Labour						170,000			170,000	
			Contract Services									-	
			Materials						254,000			254,000	
			Other									-	424,000
Service to Proposed City of Whitehorse Municipal Services Building on Robert Service Way	New Extensions	2013	Labour						90,000			90,000	
			Contract Services						150,000			150,000	
			Materials						180,000			180,000	
			Other									-	420,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Laberge Substation Distribution Upgrades	Distribution	2011	Labour				17,000					17,000	
			Contract Services				264,000					264,000	
			Materials				132,000					132,000	
			Other				3,000					3,000	416,000
Grizzly Valley New Extension Out of Subdivision	New Extensions	2011	Labour				77,000					77,000	
			Contract Services				254,000					254,000	
			Materials				68,000					68,000	
			Other				16,000					16,000	415,000
Whistle Bend Stage 1 & 2 Street Lights	Street Lights	2012	Labour				4,000	2,000				6,000	
			Contract Services				-	48,000				48,000	
			Materials				244,000	91,000				335,000	
			Other				9,000	9,000				18,000	407,000
Beaver Creek Programmable Logic Control (PLC) Upgrade	Generation	2013	Labour					29,000	25,000			54,000	
			Contract Services					58,000	50,000			108,000	
			Materials					109,000	96,000			205,000	
			Other					10,000	9,000			19,000	386,000
Watson Lake Replace ABB 5HK Breakers	Generation	2015	Labour									-	
			Contract Services							70,000	70,000	140,000	
			Materials							110,000	130,000	240,000	
			Other									-	380,000
Hamilton Boulevard Main Infrastructure Extension	New Extensions	2009	Labour	40,000	5,000							45,000	
			Contract Services	18,000	48,000							66,000	
			Materials	188,000	34,000							222,000	
			Other	20,000	13,000							33,000	366,000
Whitehorse Hotsprings Road 3 Phase Conversion	Distribution	2015	Labour								218,000	218,000	
			Contract Services									-	
			Materials								145,000	145,000	
			Other									-	363,000
Oracle Hrxcellence HR Management	GP&E	2009	Labour	-	-	-						-	
			Contract Services	124,000	111,000	103,000						338,000	
			Materials	-	-	-						-	
			Other	14,000	6,000	-						20,000	358,000
Ketza Court Live Front Transformers Replacement	Distribution	2008	Labour	10,000								10,000	
			Contract Services	148,000								148,000	
			Materials	186,000								186,000	
			Other	2,000								2,000	346,000
25 Wann Road - 65 Units	New Extensions	2011	Labour				14,000					14,000	
			Contract Services				113,000					113,000	
			Materials				215,000					215,000	
			Other				1,000					1,000	343,000
Haines Junction Plant Controls Upgrade	Generation	2009	Labour		156,000		-					156,000	
			Contract Services		77,000		-					77,000	
			Materials		48,000		14,000					62,000	
			Other		43,000		-					43,000	338,000
Hotsprings Road Main Line Relocation and Upgrade	Distribution	2013	Labour						195,000			195,000	
			Contract Services									-	
			Materials						130,000			130,000	
			Other									-	325,000
Mountain Air Subdivision	New Extensions	2008	Labour	9,000								9,000	
			Contract Services	111,000								111,000	
			Materials	196,000								196,000	
			Other	1,000								1,000	317,000
Northwestel Minto	New Extensions	2012	Labour					5,000				5,000	
			Contract Services					226,000				226,000	
			Materials					76,000				76,000	
			Other					1,000				1,000	308,000
Northwestel Fox Point	New Extensions	2012	Labour					9,000				9,000	
			Contract Services					215,000				215,000	
			Materials					83,000				83,000	
			Other					1,000				1,000	308,000
Falcon Ridge Development Stage 4	New Extensions	2011	Labour				10,000	2,000				12,000	
			Contract Services				103,000	32,000				135,000	
			Materials				157,000	-				157,000	
			Other				1,000	-				1,000	305,000
Whitehorse Service Complex Yard Extension	GP&E	2015	Labour									-	
			Contract Services								300,000	300,000	
			Materials									-	
			Other									-	300,000
Takhini/Marwell Completion of Mountain Air Subdivision	Distribution	2015	Labour								60,000	60,000	
			Contract Services									-	
			Materials								240,000	240,000	
			Other									-	300,000
Destruction Bay Programmable Logic Controller Upgrade	Generation	2014	Labour							42,000		42,000	
			Contract Services							84,000		84,000	
			Materials							159,000		159,000	
			Other							15,000		15,000	300,000
5L628 Squanga Road Rebuild	Distribution	2008	Labour	10,000								10,000	
			Contract Services	200,000								200,000	
			Materials	79,000								79,000	
			Other	1,000								1,000	290,000
Destruction Bay Unit # 1 Replacement	Generation	2011	Labour			37,000						37,000	
			Contract Services			14,000						14,000	
			Materials			200,000						200,000	
			Other			24,000						24,000	275,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Watson Lake Unit # 5 Replacement	Generation	2011	Labour			22,000	-					22,000	
			Contract Services			1,000	-					1,000	
			Materials			191,000	23,000					214,000	
			Other			18,000	9,000					27,000	264,000
Yukon Government Whitehorse Copper Phase II	New Extensions	2008	Labour	15,000								15,000	
			Contract Services	146,000								146,000	
			Materials	100,000								100,000	
			Other	1,000								1,000	262,000
Display Change to Yukon Electrical Billing Statements	GP&E	2013	Labour						-			-	
			Contract Services						259,000			259,000	
			Materials						-			-	
			Other						-			-	259,000
Watson Lake Unit # 6 Major Overhaul	Generation	2013	Labour						12,500			12,500	
			Contract Services						82,500			82,500	
			Materials						152,500			152,500	
			Other						2,500			2,500	250,000
Watson Lake Unit # 1 Major Overhaul	Generation	2015	Labour								12,500	12,500	
			Contract Services								82,500	82,500	
			Materials								152,500	152,500	
			Other								2,500	2,500	250,000
Riverdale Line 4L317 Tagish Road	Distribution	2015	Labour								175,000	175,000	
			Contract Services									-	
			Materials								75,000	75,000	
			Other									-	250,000
MacDonald Road Pole Change	Distribution	2015	Labour								150,000	150,000	
			Contract Services									-	
			Materials								100,000	100,000	
			Other									-	250,000
Crestview to Mayo Road 5L628 Upgrade to 266 MCM	Distribution	2013	Labour						7,500			7,500	
			Contract Services						155,000			155,000	
			Materials						87,500			87,500	
			Other						-			-	250,000
Old Alaska Highway Bypass	Distribution	2013	Labour									-	
			Contract Services						158,000			158,000	
			Materials						90,000			90,000	
			Other									-	248,000
Watson Lake Unit # 3 Major Overhaul	Generation	2012	Labour					12,000				12,000	
			Contract Services					82,000				82,000	
			Materials					150,000				150,000	
			Other					3,000				3,000	247,000
Fish Lake Unit #1 Spillway	Generation	2010	Labour			20,000	2,000					22,000	
			Contract Services			180,000	16,000					196,000	
			Materials			1,000	-					1,000	
			Other			11,000	8,000					19,000	238,000
Communication Equipment	GP&E	Annual	Labour	-	-	-	-	-	-	-	-	-	
			Contract Services	-	-	-	-	-	-	-	-	-	
			Materials	57,000	47,000	-	49,000	57,000	-	11,000	12,000	233,000	
			Other	-	-	-	-	-	-	-	-	-	233,000
Arkell Subdivision Upgrade	Distribution	2008	Labour	5,000	-							5,000	
			Contract Services	13,000	-							13,000	
			Materials	2,000	197,000							199,000	
			Other	1,000	-							1,000	218,000
Windows 7 Upgrades	GP&E	2012	Labour					-	-			-	
			Contract Services					61,000	146,000			207,000	
			Materials					-	-			-	
			Other					-	-			-	207,000
Whistle Bend Way Light Additions	Street Lights	2011	Labour			2,000	13,000					15,000	
			Contract Services			21,000	126,000					147,000	
			Materials			37,000	(1,000)					36,000	
			Other			2,000	5,000					7,000	205,000
General Drafting and Mapping	New Extensions	Annual	Labour	41,000	71,000				74,000			186,000	
			Contract Services	-	-				-			-	
			Materials	-	-				-			-	
			Other	5,000	4,000				6,000			15,000	201,000
Watson Lake Unit # 5 Major Overhaul	Generation	2014	Labour							10,000		10,000	
			Contract Services							66,000		66,000	
			Materials							122,000		122,000	
			Other							2,000		2,000	200,000
5L626 Double Circuit Line to Whistle Bend Substation	Distribution	2011	Labour				7,000					7,000	
			Contract Services				125,000					125,000	
			Materials				68,000					68,000	
			Other				-					-	200,000
Grey Wolf 1583 Wann Road	New Extensions	2012	Labour					13,000				13,000	
			Contract Services					112,000				112,000	
			Materials					72,000				72,000	
			Other					1,000				1,000	198,000
Mah's Point Condominiums	New Extensions	2012	Labour					24,000				24,000	
			Contract Services					76,000				76,000	
			Materials					92,000				92,000	
			Other					1,000				1,000	193,000
Hotsprings Road Upgrade	Distribution	2011	Labour				41,000					41,000	
			Contract Services				93,000					93,000	
			Materials				47,000					47,000	
			Other				9,000					9,000	190,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Upgrade Laberge Substation Transformer to 10 MVA	Distribution	2011	Labour				-					-	
			Contract Services				1,000					1,000	
			Materials				188,000					188,000	
			Other									-	189,000
9L - Km 129 to Km 132 South Klondike Highway - Distribution Line Rebuild	Distribution	2008	Labour	4,000								4,000	
			Contract Services	112,000								112,000	
			Materials	70,000								70,000	
			Other	3,000								3,000	189,000
Pine Street Light Replacement	Street Lights	2010	Labour	3,000		5,000						8,000	
			Contract Services	11,000		99,000						110,000	
			Materials	10,000		56,000						66,000	
			Other	1,000		1,000						2,000	186,000
Little Atlin Feeder Tap	New Extensions	2008	Labour	25,000								25,000	
			Contract Services	64,000								64,000	
			Materials	83,000								83,000	
			Other	6,000								6,000	178,000
New 250kW Mobile Generator	Generation	2013	Labour									-	
			Contract Services									-	
			Materials						175,000			175,000	
			Other									-	175,000
Office Furniture	GP&E	Annual	Labour				-	-	-	-	-	-	
			Contract Services				-	-	-	-	-	-	
			Materials				72,000	24,000	44,000	-	34,000	174,000	
			Other				-	-	-	-	-	-	174,000
Fish Lake Unit # 1 Tailrace Reconstruction	Generation	2011	Labour				7,000					7,000	
			Contract Services				163,000					163,000	
			Materials				-					-	
			Other				3,000					3,000	173,000
Fish Lake Unit # 2 Step-Up Transformer	Generation	2012	Labour					26,000				26,000	
			Contract Services					36,000				36,000	
			Materials					102,000				102,000	
			Other					8,000				8,000	172,000
Fish Lake Unit # 2 Turbine Inlet Valve (TIV) Replacement	Generation	2012	Labour					30,000				30,000	
			Contract Services					82,000				82,000	
			Materials					50,000				50,000	
			Other					9,000				9,000	171,000
Ingram 6-Plex Subdivision	New Extensions	2011	Labour				3,000					3,000	
			Contract Services				49,000					49,000	
			Materials				113,000					113,000	
			Other				-					-	165,000
Yukon Government Ingram Subdivision Street Lights	Street Lights	2009	Labour		1,000	-						1,000	
			Contract Services		-	1,000						1,000	
			Materials		112,000	49,000						161,000	
			Other		-	-						-	163,000
Downtown Office Interior Renovations	GP&E	2012	Labour									-	
			Contract Services					62,000	100,000			162,000	
			Materials									-	
			Other									-	162,000
Yukon Government Haines Junction Willow Acres Residential Infill	New Extensions	2011	Labour			1,000	4,000					5,000	
			Contract Services			1,000	88,000					89,000	
			Materials			34,000	30,000					64,000	
			Other			1,000	2,000					3,000	161,000
Lot 1146 Crestview Development	New Extensions	2012	Labour					5,000				5,000	
			Contract Services					64,000				64,000	
			Materials					92,000				92,000	
			Other					-				-	161,000
Regulator to North Klondike Highway	Distribution	2012	Labour					7,000				7,000	
			Contract Services					69,000				69,000	
			Materials					77,000				77,000	
			Other					1,000				1,000	154,000
Transformers & Regulators	Transformers	Annual	Labour									-	
			Contract Services									-	
			Materials		80,000	-	9,000	34,000	10,000	10,000	10,000	153,000	
			Other									-	153,000
Purchase Unit for Pelly Crossing Power Plant	Generation	2010	Labour			-	-					-	
			Contract Services			34,000	-					34,000	
			Materials			66,000	50,000					116,000	
			Other			1,000	-					1,000	151,000
Whitehorse Service Complex Pole Storage	GP&E	2013	Labour									-	
			Contract Services						30,000			30,000	
			Materials						120,000			120,000	
			Other									-	150,000
Whitehorse Asset Management - Creat a Pole Database	GP&E	2014	Labour						75,000	75,000		150,000	
			Contract Services									-	
			Materials									-	
			Other									-	150,000
Morley and Peel Street Light Replacement	Street Lights	2011	Labour				5,000					5,000	
			Contract Services				109,000					109,000	
			Materials				35,000					35,000	
			Other				1,000					1,000	150,000
Destruction Bay Plant Foundation Refurbishment	Generation	2013	Labour									-	
			Contract Services						150,000			150,000	
			Materials									-	
			Other									-	150,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
Wharf Lighting 1st Ave Whitehorse	Street Lights	2011	Labour				3,000					3,000	
			Contract Services				11,000					11,000	
			Materials				132,000					132,000	
			Other				1,000					1,000	147,000
Lewes Lake Substation Conversion	Distribution	2015	Labour								30,000	30,000	
			Contract Services									-	
			Materials								116,000	116,000	
			Other									-	146,000
Yukon Government Lights on 8th Street Watson Lake	Street Lights	2012	Labour					2,000				2,000	
			Contract Services					106,000				106,000	
			Materials					35,000				35,000	
			Other					-				-	143,000
Takhini North Subdivision	Street Lights	2009	Labour		7,000	7,000						14,000	
			Contract Services		4,000	7,000						11,000	
			Materials		74,000	42,000						116,000	
			Other		1,000	-						1,000	142,000
Whitehorse Airport Hanger D Area Rebuild	Distribution	2015	Labour								80,000	80,000	
			Contract Services									-	
			Materials								60,000	60,000	
			Other									-	140,000
Distribution SCADA Equipment	GP&E	2010	Labour			36,000						36,000	
			Contract Services			1,000						1,000	
			Materials			96,000						96,000	
			Other			5,000						5,000	138,000
Beaver Creek Control Room Separation from Plant	Generation	2012	Labour					-				-	
			Contract Services					16,000				16,000	
			Materials					108,000				108,000	
			Other					13,000				13,000	137,000
Whitehorse Area Line Clearance Upgrades	Distribution	2014	Labour						40,000	42,000		82,000	
			Contract Services									-	
			Materials						25,000	28,000		53,000	
			Other									-	135,000
Takhini North Upgrade	Distribution	2010	Labour			52,000						52,000	
			Contract Services			16,000						16,000	
			Materials			51,000						51,000	
			Other			15,000						15,000	134,000
Whitehorse Copper Light Additions	Street Lights	2008	Labour	2,000								2,000	
			Contract Services	69,000								69,000	
			Materials	59,000								59,000	
			Other	1,000								1,000	131,000
Lot 405 Takhini	New Extensions	2012	Labour					4,000				4,000	
			Contract Services					31,000				31,000	
			Materials					95,000				95,000	
			Other					-				-	130,000
Diamond Ranch Extension	New Extensions	2011	Labour				2,000					2,000	
			Contract Services				100,000					100,000	
			Materials				28,000					28,000	
			Other				-					-	130,000
9L Reliability Upgrade Squanga Lake Area	Distribution	2008	Labour	33,000	24,000							57,000	
			Contract Services	14,000	6,000							20,000	
			Materials	21,000	18,000							39,000	
			Other	9,000	3,000							12,000	128,000
Whistle Bend Substation Transformer	Distribution	2011	Labour				-					-	
			Contract Services				1,000					1,000	
			Materials				126,000					126,000	
			Other				-					-	127,000
Echo Lake Road Upgrade	Distribution	2009	Labour	17,000	29,000							46,000	
			Contract Services	14,000	15,000							29,000	
			Materials	15,000	22,000							37,000	
			Other	6,000	9,000							15,000	127,000
Stan McCowan Subdivision	New Extensions	2008	Labour	11,000								11,000	
			Contract Services	27,000								27,000	
			Materials	85,000								85,000	
			Other	3,000								3,000	126,000
Fish Lake Unit # 1 Replacement Wheel	Generation	2010	Labour		-	-						-	
			Contract Services		-	-						-	
			Materials		76,000	38,000						114,000	
			Other		4,000	7,000						11,000	125,000
E-Post Billing	GP&E	2013	Labour						-			-	
			Contract Services						125,000			125,000	
			Materials						-			-	
			Other						-			-	125,000
Yukon Government Ross River Pole Relocation	New Extensions	2012	Labour					15,000				15,000	
			Contract Services					67,000				67,000	
			Materials					31,000				31,000	
			Other					9,000				9,000	122,000
Stewart Crossing Plant Improvements	Generation	2014	Labour									-	
			Contract Services							120,000		120,000	
			Materials									-	
			Other									-	120,000
Fish Lake Unit # 1 Spillway Diversion Structure	Generation	2014	Labour						2,000	9,000		11,000	
			Contract Services						16,000	82,000		98,000	
			Materials						-	-		-	
			Other						2,000	9,000		11,000	120,000

The Yukon Electrical Company Limited
Breakdown of Project Costs

Project Name	Appropriation Type	Year Capitalized	Expense type	2008	2009	2010	2011	2012	2013	2014	2015	Total	Project Total
F.H. Collins Secondary School Transformer	New Extensions	2012	Labour				2,000	13,000				15,000	
			Contract Services				26,000	1,000				27,000	
			Materials				41,000	28,000				69,000	
			Other				3,000	6,000				9,000	120,000
High Voltage Switching Cubicle and Termination for Old Crow Plant	Generation	2012	Labour				-	32,000				32,000	
			Contract Services				-	13,000				13,000	
			Materials				14,000	37,000				51,000	
			Other				6,000	8,000				14,000	110,000
Two City Water Wells in Riverdale	New Extensions	2009	Labour		6,000							6,000	
			Contract Services		26,000							26,000	
			Materials		74,000							74,000	
			Other		1,000							1,000	107,000
New Country Residential Subdivision in Haines Junction	New Extensions	2010	Labour			3,000						3,000	
			Contract Services			71,000						71,000	
			Materials			31,000						31,000	
			Other			-						-	105,000
Yukon Government Tagish Landfill	New Extensions	2012	Labour					4,000				4,000	
			Contract Services					68,000				68,000	
			Materials					30,000				30,000	
			Other					2,000				2,000	104,000
Watson Lake Hospital Upgrade	New Extensions	2011	Labour				24,000					24,000	
			Contract Services				24,000					24,000	
			Materials				44,000					44,000	
			Other				12,000					12,000	104,000
Laberge Substation 34.5kV Conductor Upgrade	Distribution	2012	Labour					45,000				45,000	
			Contract Services					8,000				8,000	
			Materials					40,000				40,000	
			Other					10,000				10,000	103,000
Whitehorse Various Service Complex Renovations	GP&E	2014	Labour									-	
			Contract Services							100,000		100,000	
			Materials									-	
			Other									-	100,000
Whitehorse Service Complex Parking Lot Expansion and Improvements	GP&E	2013	Labour									-	
			Contract Services						100,000			100,000	
			Materials									-	
			Other									-	100,000
Watson Lake Underground Subdivision Replacement	Distribution	2015	Labour								40,000	40,000	
			Contract Services									-	
			Materials								60,000	60,000	
			Other									-	100,000
Watson Lake Power Plant Connection to Town Water Supply	GP&E	2014	Labour									-	
			Contract Services							100,000		100,000	
			Materials									-	
			Other									-	100,000
Watson Lake 3-Phase System Protection Upgrade	Distribution	2011	Labour			7,000						7,000	
			Contract Services			28,000						28,000	
			Materials			64,000						64,000	
			Other			1,000						1,000	100,000
Upper Liard - Replace Liard River Crossing	Distribution	2015	Labour									-	
			Contract Services								60,000	60,000	
			Materials								40,000	40,000	
			Other									-	100,000
Trail Lighting along Whitehorse Waterfront to Shipyards Park	Street Lights	2011	Labour				2,000					2,000	
			Contract Services				68,000					68,000	
			Materials				30,000					30,000	
			Other				-					-	100,000
Riverdale Lewes Substation 25kV Transformer	Distribution	2014	Labour									-	
			Contract Services									-	
			Materials							100,000		100,000	
			Other									-	100,000
Pelly Crossing Substation Fence	Distribution	2013	Labour									-	
			Contract Services						100,000			100,000	
			Materials									-	
			Other									-	100,000
Old Crow Staff Accomodations	GP&E	2014	Labour									-	
			Contract Services							100,000		100,000	
			Materials									-	
			Other									-	100,000
Marwell Lot 14 Transformer Upgrade	Distribution	2014	Labour							20,000		20,000	
			Contract Services									-	
			Materials							80,000		80,000	
			Other									-	100,000
Jack Hulland School Upgrades	Distribution	2013	Labour						30,000			30,000	
			Contract Services									-	
			Materials						70,000			70,000	
			Other									-	100,000
Haines Junction Plant Upgrades	Generation	2009	Labour	31,000								31,000	
			Contract Services	4,000								4,000	
			Materials	51,000								51,000	
			Other	14,000								14,000	100,000
Carmacks North Main Line Rebuild	Distribution	2014	Labour							60,000		60,000	
			Contract Services									-	
			Materials							40,000		40,000	
			Other									-	100,000
Carmacks Fuel System Upgrade	Generation	2012	Labour					28,000				28,000	
			Contract Services					46,000				46,000	
			Materials					19,000				19,000	
			Other					7,000				7,000	100,000
	Total			**7,745,000.00**	**4,316,000.00**	**6,909,000.00**	**12,335,000.00**	**11,644,000.00**	**18,961,000.00**	**22,061,000.00**	**20,207,000.00**	**104,178,000.00**	**104,178,000.00**
	Total Annual Capital Additions			**9,906,000.00**	**6,253,000.00**	**9,388,000.00**	**14,938,000.00**	**14,590,000.00**	**20,282,000.00**	**22,417,000.00**	**20,820,000.00**	**118,594,000.00**	**118,594,000.00**
	%			**78.18%**	**69.02%**	**73.59%**	**82.57%**	**79.81%**	**93.49%**	**98.41%**	**97.06%**	**87.84%**	**87.84%**

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Reference: New 250kW Mobile Generator, YECL Application, page 9-45

This generator provides contingency power to smaller communities. Contingency situations include emergency backup and scheduled maintenance shutdowns of power plants. The unit is also used during other system improvement projects to supply temporary power.

YECL presently has a 350kW mobile unit as stated in BC #4 that is unable to meet the current peak loads of the communities it serves.

Request:

(a) Please provide the justification for the purchase of this unit.

(b) How does YECL plan to utilize the 350kW mobile?

Response:

(a) The 250kW mobile generator is a multi-configurable low voltage unit (208/480VAC) used to provide backup to the communities of Keno, Swift River and Deep Creek. The 350kW mobile generator supplies only 2400v and cannot be utilized in these communities. On January 1, 2012, there was an extended outage in Keno due to loss of supply to the community. Emergency crews were dispatched with the existing low voltage mobile generator stationed in Whitehorse to restore power to the community. This outage was over 11 hours in length when the temperature was 30 degrees below zero. A second outage to the community the following day was over 16 hours due to malfunction of the mobile generator. Without a secure supply from the Yukon Interconnected System and with malfunction of the mobile generator, the community was in an emergency situation. As a result of the outage debrief, Yukon Electrical examined the need for a second low voltage mobile generator given that this single unit serves as backup to multiple communities throughout our service area. These low voltage mobile generators also assist Yukon Electrical to provide power to small sections of the distribution system during system improvements or long duration outages.

(b) The existing 350kW unit is in good working condition and able to supply adequate contingency power to the communities of Beaver Creek and Destruction Bay during the summer months. The unit has less than $50,000 of net book value as of the end of 2012 so it provides additional contingency with negligible additional cost to ratepayers. As such, Yukon Electrical plans to keep the unit in service.

YUB-YECL-63

Reference: Line item – Fish Lake Unit #2 SCADA, YECL Application, page 9-45

Request:

Please provide the benefits YECL obtains by installing this SCADA system.

Response:

The benefits of a SCADA system include: real time indication of unit loading and alarms; immediate annunciation to staff of unit shut downs and alarms; and frequent collection of data in terms of unit loading, performance and alarm history as well as automated controls. The automated controls will help to optimize water levels.

YUB-YECL-64

Reference: Line item – Fish Lake Unit #2 Penstock Improvements, YECL Application, page 9-45

Request:

Please provide any details on what the improvements are and how the operation of Fish Lake Unit #2 will benefit.

Response:

Details consist of Penstock #2 access road drainage improvements and slope stabilization to minimize an identified embankment failure risk. The operational benefit is in having a stabilized bank due to better drainage which will allow Yukon Electrical to continue to use this access road to inspect hydro infrastructure. If this project is not completed, there is a risk that the access road will be washed away and Yukon Electrical will lose access to its hydro facilities.

YUB-YECL-65

Reference: Line item – Miscellaneous O/H Services – Various Subdivisions, YECL Application, page 9-46

Capital expenditures required for the connection of new residential and commercial customers in Yukon Electrical's service area in compliance with Terms and Conditions. Any new extension (driven by a customer) that is under $25k is included in this.

Request:

Please provide details to the Board on how this level of expenditure was determined.

Response:

Yukon Electrical has determined its new extension capital forecast, including the Miscellaneous O/S Services, based on the knowledge it has of areas of development within its service areas as well as based on historical customer additions. New extensions are, on average, 75-80% funded by customer contributions. The net investment for the New Extension Category, including Miscellaneous O/S Services, is as follows:

		2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast
New Extensions	Schedule 9.1, L.10	6,078	4,919	5,149	5,307	5,570
Customer Contributions *		(5,149)	(3,097)	(3,903)	(4,320)	(4,160)
Yukon Electrical Net Investment		929	1,822	1,246	987	1,410

* Total contributions as per Schedule 8.12, L.3, less contributions received for Street Lights.

YUB-YECL-66

Reference: Line item – Miscellaneous Distribution Pole Replacement, YECL Application, page 9-48

Various deficient poles are identified through distribution system inspections, test and treat program and in unplanned situations. System inspections identify ground rot, pest infestation, broken or damaged poles and electrical degradation. The test and treat program identifies internal condition of the pole. Unplanned situations include emergency situations due to failure of the pole and forced projects.

Request:

(a) Please provide an explanation on how the program is tracked and how pole replacement is prioritized.

(b) For this item, what is the forecast O&M expenditure for each of the test years?

Response:

(a) When poles and structures are identified as deficient through any of the programs noted, a needs statement is completed to collect the relevant information. Once completed, the needs statement is submitted by field personnel to the Team Lead and the Superintendent Operations and Maintenance. The project is prioritized, catalogued in a database and tracked to completion.

(b) There are no amounts included in O&M for this item.

YUB-YECL-67

Reference: Line item – PCB Identification and Transformer Change Outs, YECL Application, page 9-48

Identification of Polychlorinated Biphenyl (PCB) content of all oil-filled equipment, in compliance with the Canadian Environmental Protection Act 1999. Oil-filled equipment containing PCBs in a concentration of at least 50 mg/kg but less than 500 mg/kg is being removed from service.

Both YEC and YECL have been working on this issue since the mid-1980s and do not appear to making progress, as costs continue to be incurred. In the GRA, costs have been incurred or allocated for this project between 2011-15.

Request:

(a) What is YECL's estimate of how many of the transformers remaining still contain PCBs?

(b) Please provide the plan and schedule that YECL plans to follow to have all transformers containing PCB's disposed of for each of the test years.

Response:

(a) Yukon Electrical has completed testing and identification of approximately 5,000 transformers throughout all service areas. At this time, it is estimated that there are approximately 1,000 pieces of equipment remaining that will require testing and identification of PCB content. There are 10 transformers that require removal from service and disposal as a result of 2012 identification.

(b) Yukon Electrical plans to test and identify PCB content of approximately 1,000 transformers in 2013. Any transformers identified as having unacceptable PCB content will be removed from service and disposed in 2013 and 2014.

YUB-YECL-68

Reference: Line item – Whitehorse Safety Code Corrections, YECL Application, page 9-49

Request:

Please provide a list of what safety code corrections are included in this expenditure.

Response:

Yukon Electrical completes Safety Code Audits of its distribution system projects to ensure compliance with applicable regulations such as the Canadian Electrical Code and the Alberta Electrical Utility Code. These audits are part of Yukon Electrical's quality control and commissioning program. ATCO Electric, under the Safety Codes Act of Alberta, has established a Quality Management Plan (QMP) that is approved by the Safety Codes Council. This grants ATCO Electric Accredited Corporation status. As a result, ATCO Electric is legally authorized to enforce the Alberta Electrical Utility Code (inspection authority having jurisdiction).for all electrical facilities and systems that are owned by, or under the care and control of, the Accredited Corporation. This includes Yukon Electrical. Please refer to YUB-YECL-68 Attachment 1 for a list of the specific projects that required correction.

Area	Number	Location	Description of Work to Be Completed
Whitehorse North	Y11489	Lot 33 Pilot Mtn	Lower ground moulding /ground rod exposed / transformer grounding
	Y12173	Lot 1066 Alaska hwy	megger reading missing/ground moulding
	Y12009	Grizzley Valley - stage 3	Remove switch tag/install 2nd ground moulding on gangswitch pole
Porter Creek and Beyond	Y10891	MacDonald rd rebuild	loose bonding bolt / loose guy guard / anchor bonding
	Y11097	Crestview	Lower ground moulding / underground warning stickers / megger tag
	Y11260	30 MacDonald rd	Lower ground moulding / preform not in fiber rod / 5/8 pal nuts
	Y12319	Lot 58-2 Dogwood	Ground moulding not buried / pal nuts / outage required
	Y12320	Lot 55 Dogwood	megger reading / inspect down ground / tighen guy wire
Takhini and Marwell	Y12200	Lot 10 Raven's Ridge	Install seal on breaker cabinet/grounding correction
Lobird / Macrae and Beyond	Y10856	Carcross Corner St. Lights	Underground cable warning stickers / asset tags
	Y11516	lot 39 Mt. Sima	transformer grounding / guy preform not seated in anchor eye

YUB-YECL-69

Reference: Line item – Miscellaneous Street Light Replacements, YECL Application, page 9-50

Planned replacement program based on street light inspections and condition assessment of infrastructure. Condition assessment is based on performance of street lights, deficiencies or substandard conditions and the general physical condition. Inspection of the general physical condition includes the base and metal structure for deterioration, rust, broken bolts and damage.

Request:

Please provide more details pertaining to the planned replacement program for each of the test years.

Response:

In 2013, Yukon Electrical plans to replace lights on and near Hickory Street. Yukon Electrical will be replacing 18 street light davits and installing approximately 560m of underground electrical wire.

In 2014, Yukon Electrical plans to replace lights on Pine Street between 12th avenue and Ponderosa Street. This project will include replacement of 28 street light davits and 980m of underground electrical wire.

In 2015, Yukon Electrical plans to replace lights on Alsek Road. This project will include replacement of 30 street light davits and 1,110m of underground electrical wire.

YUB-YECL-70

Reference: Line item – Replacement of Meters and Installing New Meters, Application, page 9-50

The installation of new meters is required to accommodate load growth associated with customer requests for service. These expenditures allow Yukon Electrical to meet its obligation to provide metered service connections. The capital meter additions are planned based on known areas of development and expected connection requests. New meters are also required to replace obsolete or end of life meters as identified by Measurement Canada. The new meters to be installed in 2013 will be AMR compatible in preparation for the conversion to AMR in 2014 and 2015.

Locations include Chestnut, Mulberry and Hickory Street.

Request:

(a) Please explain why an additional $50,000 in 2014-15 is required for replacement meters after expending $600,000 through this project?

(b) Are any AMR meters included in this line item?

Response:

(a) The $50,000 is primarily for meter replacement outside of the area that will have AMR installed. The following communities are not part of the AMR project:

Watson Lake

Lower Post

Upper Liard

Swift River

Ross River

Old Crow

Stewart Crossing

Keno

Pelly Crossing

Carmacks

Beaver Creek

Destruction Bay – Burwash

Haines Junction

(b) No AMR meters are forecast in this line item.

YUB-YECL-71

Reference: Tools, Instruments & Equipment, YECL Application, Schedule 9.1, line 18

Request:

(a) Does YECL have a tool replacement policy? If so, please provide a copy of YECL's tool replacement policy.

(b) What is the impact if any of the tools or equipment expenditures are denied by the Board?

Response:

(a) Yukon Electrical's tool replacement policy is based on its Safety Standards Manual (SSM) Section 300: Equipment Requirements. Please refer to the following attachments:

- YUB-YECL-71 Attachment 1 - SSM Section 300: Equipment Requirements
- YUB-YECL-71 Attachment 2 - SSM Section 900: Working with Powered Tools
- YUB-YECL-71 Attachment 3 – Policy B19: Protective Clothing and Safety Equipment
- YUB-YECL-71 Attachment 4 - SSM Appendix A: Equipment Test and Service Schedule

In general, any equipment or tool found to be defective, excessively worn or in unsuitable condition for its intended purpose is to be removed from service and repaired or replaced as necessary.

(b) Yukon Electrical requires specialized tools and equipment to complete work on the distribution power system and ancillary equipment. Tools and equipment include high voltage insulated tools, rubber gloves, revenue meter test equipment, insulation testers, survey equipment, Arc Flash Protective Clothing, underground locators, mechanical tools for work on diesel generators, and digital recording ammeters. Yukon Electrical would be unable to competently and safely work on and around the distribution power system and other associated equipment without these specialized tools.

SECTION 300: EQUIPMENT REQUIREMENTS

301 Specifications and Certifications

STANDARDS:

1. Where ATCO Electric has approved equipment it must be used.

2. In using the equipment, employees must not exceed the rated capacity or any other limitations described in the manufacturer's specifications or as certified (stamped and signed) by a professional engineer.

3. All equipment must be constructed, installed, operated, maintained, stored, serviced and tested according to the manufacturer's specifications or as certified (stamped and signed) by a professional engineer.

4. No modifications may be made to any equipment that could affect its structural integrity or stability unless it is performed in accordance with the manufacturer's specifications or as certified (stamped and signed) by a professional engineer.

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APPLYING THE STANDARDS:

For approved equipment, refer to the Tool Catalogue on the intranet or the Standards group.

If manufacturer specifications do not exist, specifications certified (stamped and signed) by a professional engineer may be used.

Do not use equipment that is damaged or worn so that its strength or stability is in question. Remove all damaged equipment from service and report it to your supervisor.

302 Equipment Safeguards

STANDARDS:

1. Whenever possible, employees must use existing safeguards or put safeguards in place to prevent contact with machinery or equipment that may be hazardous.

2. Safeguards must not be tampered with or removed except while performing maintenance, checks, repairs or adjustments to the equipment.

3. If a safeguard must be temporarily removed or made ineffective, the employee must:

    - Lock and tag the equipment to make it inoperable; or

    - Put a temporary alternate protective measure in place that provides an equivalent level of safety; and

    - Replace the safeguard as soon as the task is completed and check that it is functioning properly before leaving.

4. If safeguards are unavailable or impractical, personal protective equipment must be worn or an alternate procedure used to eliminate or control the hazard.

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5. Loose-fitting clothing is prohibited near moving parts of machinery.

APPLYING THE STANDARDS:

Identify equipment hazards during the job planning process. Equipment hazards that require safeguards include:

- Moving parts of machinery;
- Points of machinery that cut, shape or bore;
- Heated or cold surfaces that could cause skin to freeze, burn or blister;
- Energized electrical equipment;
- Equipment that throws debris; and
- Any other machinery, function or process that may cause injury.

303 Identification of Unsafe Items/Equipment

STANDARDS:

All tools and equipment that are not in safe operating condition must not be used. If the tool or equipment cannot be immediately repaired it must be tagged with a defective equipment tag to warn others.

This standard does not apply where other defective electrical system identification procedures are in place.

APPLYING THE STANDARDS:

Any employee who identifies or discovers a tool or piece of equipment that appears unsafe to use or has an expired re-certification date, must immediately cease operating the tool or equipment. When immediate repair cannot take place, the employee must affix a completed “Defective Equipment” tag to the item where it can be clearly seen.

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The employee must notify the person responsible for the tool or equipment; or if that person is not known, their supervisor.

Defective equipment tags must not be removed until repairs are complete.

Tags shall be no less than 5" X 3" and contain the following information:

- The warning "DANGER – Defective Equipment"
- The statement "Do not remove this tag"
- Explanation of the defect
- Printed name of the employee that discovered the defect.

Defective equipment tags are available through reprographics (0205-0075-0309)

304 Protective Equipment Requirements

STANDARDS:

All employees must use approved protective equipment to control hazards not previously eliminated through engineering and administrative controls.

All visitors to a location (employees or others) must supply and wear their own appropriate protective equipment or they are not allowed on site.

NOTE: ATCO Electric promotional clothing is not *Arc Flash Protective Clothing*

APPLYING THE STANDARDS:

For all construction, maintenance and warehousing work activities, lateral impact hard hats, safety glasses (with side shields) and CSA green triangle with an orange Ω symbol safety footwear with ankle

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support must be worn, unless the hazard assessment describes where a different barrier is required. Note: although the CSA safety footwear with the Ω symbol supplies electrical protection it is not to be counted on as a barrier to electric hazards because the condition (e.g. wet, dirty, shunted by spur) will affect it.

For additional and alternate personal protective equipment requirements, refer to Table 304-1.

The only exceptions are:

Hard Hats – not required when driving vehicles or for indoor work where there is no risk of head injury (e.g., working in your office).

Safety Footwear – can be substituted with regular footwear for comfort while driving a vehicle where there is no risk of injury to feet, or to allow the safety footwear to dry and warm up during breaks.

Safety Glasses – not required for office work or when using equipment such as binoculars or survey transits, where glasses may impede the operator's vision, or where greater eye protection is required (e.g., welding mask, full face shield or safety goggles). Refer to specific activities in Table 304-1 for details.

📖 Management Guide Policy B-19: Protective Clothing & Safety Equipment

Table 304-1

Additional/Alternate Protective Equipment Requirements	
Handling rough or sharp-edged materials	Leather gloves or cut resistant gloves
Working with ignition sources near flammable Substances	See Section *517*
Working with chemicals	See Section 401

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Additional/Alternate Protective Equipment Requirements		
Working in *potentially* hazardous atmospheres	See Section 402	
Working with sulphur hexafluoride (SF6)	See Section 403	
Working in *potential* hydrogen sulphide (H_2S) areas	See Section 404	
Working in areas potentially contaminated with hanta virus	See Section 405	
Working in *restricted or* confined spaces	See Section 502	
Working at heights	See Section 503	
Working in hot and cold environments	See Section 508	
Working in noisy environments	See Section 509	
Working *in/over* water or ice *covers*	See Section 511*/512*	
Working on highways, secondary roads and road allowances	See Section 601	
Exposing underground electric facilities	See Section 703	
Working with electricity	See Section 800	See *Arc* Flash Protective Clothing requirements: Table 304-2 and 304-3
Installing and removing *self-contained* power meters	See Section 805	
Working on control wiring systems	See Section 806	
Working on generation, substation & telecom. Battery banks, Chargers, Uninterruptible Power Systems & Associated Equipment	See Section 807	

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Additional/Alternate Protective Equipment Requirements	
Welding	See Section *518*
Working with explosive actuated tools	See Section 901
Working with grinders and metal chop saws	See Section 903
Working with vibrating tools	See Section 905
Working with chain saws	See Section 906
Vehicle and equipment operation	See Section 1000
Operating *All-Terrain* off-road vehicles (ATVs, *UTVs*, snowmobiles)	See Section 1005

Arc Flash Protective Clothing

1. Employees issued *an Arc Flash Protective Clothing* system shall wear and keep a supply of garments with them at all times to maintain readiness for all work related hazards.

2. Where there is a risk of arc flash, only workers wearing *Arc Flash Protective Clothing* and appropriate PPE shall be permitted in the established work zone/arc flash boundary.

3. *Arc Flash Protective Clothing* may be layered to increase the level of protection. Clothing worn next to skin under the minimum outer layers in *Table 304-3 shall be Arc Flash Protective Clothing or non-melting natural fibre clothing like cotton or wool(an incidental amount of other material, e.g. elastic for the waist band or plastic bra clasps, are permitted).Metallic articles shall not be worn next to skin.*

4. Clothing systems and Personal Protective Equipment used shall provide a minimum Arc Thermal Protection Value (ATPV) of 8 cal/cm^2 protection.

5. If the use of *Arc Flash Protective Clothing* and Arc Rated PPE introduces additional hazards, the safe work plan must be reviewed and revised to make sure all hazards are reduced to the lowest practical level.

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Table 304-2

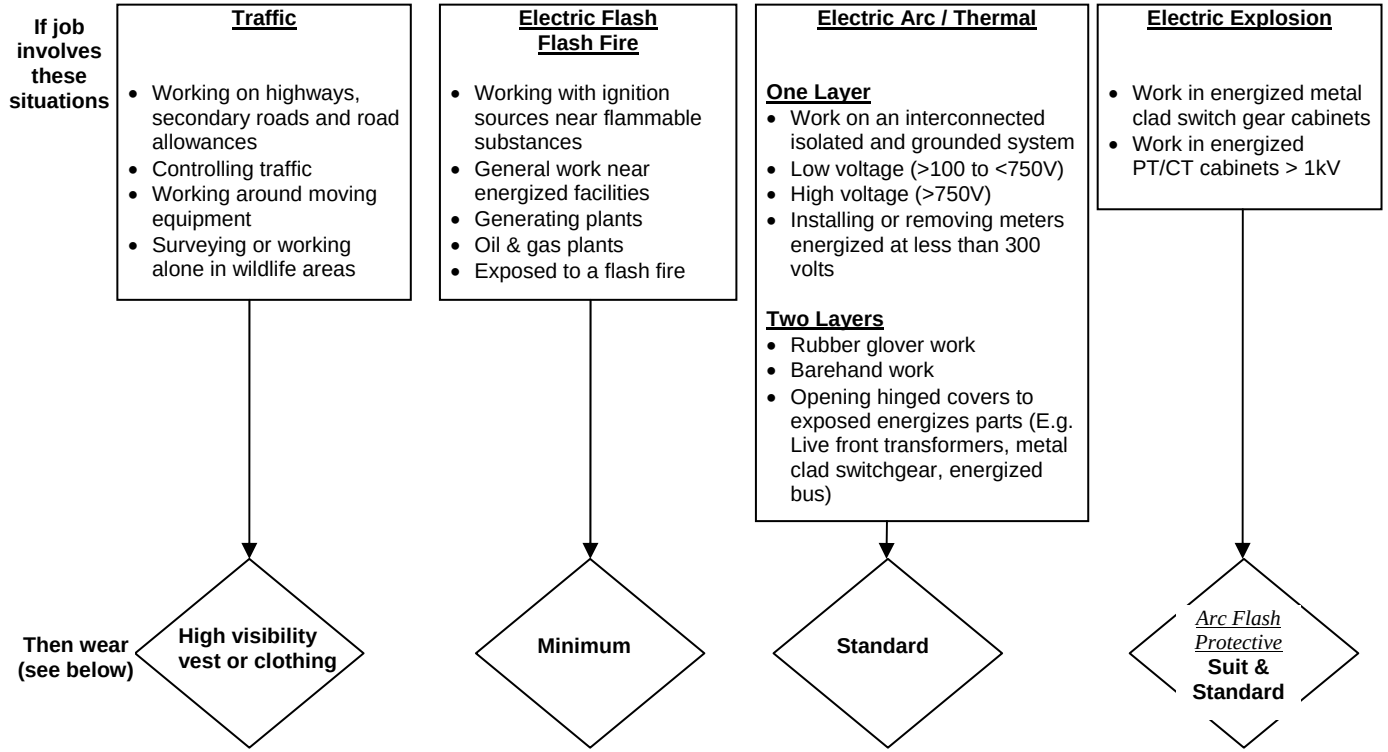

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Table 304-2(Cont'd)

Jobs with potential exposure to electrical contact, uncontrolled arc, thermal, ignition sources, flash fire, and traffic hazards.

MINIMUM	STANDARD
District Construction Inspector Line Trades Trainer Surveyors Communication Technologists Technical Resources Technologists Mechanical Technologists Engineering Assistants Labourer/Groundman (energized areas) Coordinators, Supervisors, Managers	Power Lineman Journeyman Serviceman Power Line Technician Team Lead - Line Construction Lead Power Line Technician Team Lead – Service Meter Technologists Electrical Technologists Field Services Representative Electricians Maintenance Technician Equipment Operator

Minimum layers for thermal protection, qualified materials to eliminate ignition, comfort, garment durability, hygienic practices, and cleaning frequency support the allotment of *Arc Flash Protective Clothing items in this table*.

MINIMUM = occasionally requires *Arc Flash Protective Clothing*.

STANDARD = requires *Arc Flash Protective Clothing*.

OTHER = job requires less than minimum allotment, or job requires more than minimum or standard amount due to increased wear and tear, or away from cleaning facilities >5 days.

Items ► Men & Women	**Shirts**	**Pants**	**All-Season *Arc Flash Protective* Outerwear System**	***Arc Flash Protective* Traffic Vest**	***Arc Flash Protective* Rainwear 2 pc System**
Allotment ▼ Minimum Qty.	2	2	6	1	1
Standard Qty.	3	3	8	1	1
Other Qty.	Reduced or additional *Arc Flash Protective* items approved on a situational basis by Sr. Mgr. and reported to Advisory Team.				

Jobs with potential exposure to traffic hazards.

	Equipment Mechanic, Lead Equipment Mechanic	Warehouseman, Stockkeeper, Facilities Maint. Coordinator, Labourer/Groundman (not energized areas), CSR
Items	Coveralls – Orange, natural fiber (1) Traffic Vest	(1 set each - summer + winter) Jacket + Bib – Hi-vis, natural fiber, (1) Rainwear 2 pc System (1) Traffic Vest
Quantity	As per coverall service provider	

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Table 304-3

Typical Work	Outer Layer(s)*
Work on < 100 volts • Test bench work • Protected side of breakers and fuses • Vehicle batteries	1 layer Non-Melting Natural Fibre (cotton wool)
General work near energized facilities within an established work zone. • Visits, audits, observations • Inspections, planning • Tree work	1 layer Non-Melting Natural Fibre (cotton wool)
Generating Plants, Oil & Gas Plant	*Arc Flash Protective* layer
Work on an Isolated & Grounded System	*Arc Flash Protective* Layer
Low voltage (>100 to <750V) • Meter removal/installation • Secondary work • Rubber glove work • Facility battery banks • AC/DC Panels • Work on metal clad switchgear, breaker racked out and shutters closed	*Arc Flash Protective* layer
High voltage (>750V) • Live line work with sticks • All switching • Work near metal-clad switchgear and through the door insertion and removal of metal clad circuit breakers	*Arc Flash Protective* layer
High voltage (>750V) • Rubber glove work • Bare hand work • Opening hinged covers to exposed energized parts Ex. Live front transformers, metal clad switchgear energized bus	2 *Arc Flash Protective* Layers
Work in energized metal-clad switch gear cabinets. • Insertion or removal of breaker • Circuit breaker operation • Removal of bolted covers to expose energized parts • Voltage testing Work in energized PT/CT cabinets >1 kV	3 *Arc Flash Protective* layers & blast hood

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* The "*Arc Flash Protective* Layers" must be a minimum of 8 cal/cm2 protection. This can mean one Arc Flash Protective layer with 8-cal protection, or multiple layers adding up to 8-cal or greater. (E.g. A 6-cal shirt with a 6-cal jacket overtop is equal to 12-cal protection, and thus meets the minimum.)

Also, note that Multi-layer *Arc Flash Protective Clothing* garments such as winter wear and blast suits are considered 2 FR layers.

Note: Reduce the high temperature hazards associated with protective requirements by:

- Increasing the number and length of breaks;
- Reducing the duration of exposure to high temperatures (plan work for time of day when temperature is lower, Keeping exposure to < 1 hour during highest temperature);
- Providing water for cooling and air conditioning during breaks; and
- Constant observation to detect signs of heat stress.

See Section 507: Working in Hot and Cold Environments.

Care for *Arc Flash Protective Clothing*

- Quality of protective clothing and equipment in possession of a worker must present observable protection and appearance consistent with safe work expectations, requirements of manufacturers, and OH&S Code sections pertaining to PPE.
- *Arc Flash Protective Clothing* garments shall be laundered regularly to maintain hygienic and flame resistant properties.

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- Tears and holes in *Arc Flash Protective* Clothing garments shall be repaired with *Arc Flash Protective* materials by the supplier contracted to do repairs.

- Never wash with bleach, detergent with bleach or fabric softeners.

- Never dry with fabric softener sheets.

305 Ordering Protective Equipment

STANDARD:

Employees must select the appropriate protective equipment from the *Arc Flash Protective Clothing Catalogue* or Tool Catalogue (as applicable), located on the intranet.

APPLYING THE STANDARD:

Follow established purchase approval procedures, and contact the warehouse for ordering assistance.

For prescription safety glasses, obtain the required form from your supervisor.

306 General Care and Maintenance

STANDARD:

Employees must follow the manufacturers specifications for the care and maintenance of their protective equipment (see Applying the Standards and manufacturer's instructions).

Employees must:

- Maintain their protective equipment;

- Inspect it before each use; and

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- Remove damaged protective equipment from the work site immediately and identify it to their supervisor.

- DO NOT alter or modify protective equipment in any way.

APPLYING THE STANDARDS:

General inspection and maintenance requirements for common equipment are provided below. Refer to Appendix A for the equipment test and service schedule.

If more information is required, contact the Training Centre or the manufacturer for assistance.

Hard Hats

Inspect the shell for cracks, nicks, gouges, dents, stains, melting, pitting and damage caused by rough treatment, impact, penetration or abrasion. To check the stiffness of the shell, compress it inward from the sides about 2.5 centimeters with both hands, then release the pressure without dropping the shell. The shell should quickly return to its original shape with no deformation or cracking. If any signs of damage are observed, replace the hard hat immediately.

Inspect the suspension for cracks, tears and fraying of the suspensions straps. The suspension should be pliable and show no other signs of wear. All points in the suspension should fit tightly in their respective slots. If any of these sign of damage are observed replace the suspension immediately.

The current manufacturer of ATCO Electric hard hats recommends the shell be replaced after three years of use and the suspension after one year of use.

- Clean the hard hat with mild soap and water.

- Do not store the hard hat in direct sunlight.

- Do not place stickers or decals on hard hats except non-metallic safety orientation stickers, as required by customers.

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- Non-metallic orientation stickers must be placed at least 12 mm above the brim to maintain the hard hat's dielectric classification.

Hot Sticks and Live Line Tools

Inspect before using for:

- electrical tracking, burn marks or blisters caused by heat;
- cracks, elongation of holes, loose or bent fasteners and fittings; and
- poor operating action.

Remove and tag damaged hot sticks from service immediately and have them repaired and tested.

If a tingling sensation is felt when the tool is in contact with an energized conductor or hardware, the tool must be returned to the test lab for repair and electrical testing.

Clean and wax hot sticks and live line tools with the prescribed manufacturer's products specified in the Insulated Equipment section of the Tool Catalogue.

Before using live line tools, wipe with a silicone-impregnated cloth. DON'T use cloths that have been exposed to detergents or solvents.

When they are not in use, store tools in a bin or a protective bag to keep them dry.

Every three years, a dielectric test is required (see Appendix A). Lab tests can be coordinated through the local warehouse. Hot sticks must not be used after the expiry date.

Rubber Gloves

Inspect and test rubber gloves before first use each day and immediately following any potentially damaging incident.

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Rubber gloves must be inspected over their entire surface, and rolled and stretched gently between the hands to expose defects and embedded materials. Any glove with a sign of the inside colour showing through must not be used.

Insulating rubber gloves must be given an air test by twirling or rolling the cuffs or using a mechanical inflator. When using the inflator, take care to avoid over-inflation. **No part of the glove should be stretched more than 1.25 times its normal size.** To detect punctures, listen for escaping air and hold the gloves against your cheek to feel for escaping air.

Rubber gloves must be stored with the protector gloves removed and placed in a separate storage compartment. See the Tool Catalogue for double compartment storage bags.

Rubber gloves should not be stored when wet or dirty, except on a temporary basis, after which they should be cleaned and dried with a clean rag.

Rubber gloves should be washed frequently to remove perspiration, dirt and body salts from the interior. Rinse thoroughly to avoid possible irritation from cleaning residue, wipe dry and return (right side out) to dry. DON'T leave rubber gloves inside out, as the distortion will hasten deterioration. Also, never allow rubber gloves to dry in the sun because of the possibility of ozone damage.

If wool or cotton liners are used, these should also be washed regularly to avoid the risk of dermatitis. Use 10-4 Rubber Glove Dust to aid in pulling on and removing the gloves.

All rubber gloves must be laboratory tested every six months. Rubber gloves must not be used past the expiry date (see Appendix A).

Protector Gloves

Inspect protector gloves before first use each day and immediately following any potentially damaging incident.

Protector gloves must not be used if they have holes, tears or other defects that affect their ability to provide mechanical

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protection to the insulating rubber gloves. Keep them as free as possible from oils, greases, chemicals and other damaging materials. If they become contaminated, they may no longer be used as protector gloves, unless they are thoroughly cleansed of the contaminating substance. Check inside the protector gloves for sharp or pointed objects before fitting them over rubber gloves.

Climbing and Fall Protection Equipment

Conduct a visual inspection of climbing and fall protection equipment before first use each day:

- Check the lineman's body belt / full body harness material and stitching for excessive wear. Inspect the plastic distribution and absorption plate on the full body harness for cracks and wear.

- Check D rings, buckles and locking snaps for broken or damaged parts. Make sure locking snaps operate properly.

- Check the lanyard, fall restricting pole strap and choker strap material and stitching for wear or corrosion and loose or missing rivets and springs.

- Check that retractable lanyards operate properly and are properly attached.

- Check climber pads, straps and stitching for cracks and wear and cracked or worn buckles.

- Check that climber shaft screws are tight and the steel rings are not cracked or showing signs of excessive wear.

- Inspect gaffs for damage and check sharpness (use the plane test).

- Remove from service and re-certify or replace any personal fall arrest system that has arrested a fall.

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Self Contained Breathing Apparatus (SCBA) & Supplied Air Respirators

SCBA and supplied air respirators must be maintained and stored in a manner that prevents contamination of the equipment (i.e., cleaned, sanitized and then stored in the appropriate carrying case).

All SCBA and supplied air respirators must be inspected monthly and before and after each use to verify the following:

- All component parts are clean and in good working condition (i.e., face piece, helmet, hood, suit, head harness, valves, connecting tubes, harness assemblies, filters, cartridges and cylinders);
- Connections are tight;
- Regulators, alarms and other warning systems are functioning properly;
- End of service-life indicator and shelf-life dates are not expired;
- Pressure gauges of all breathing cylinders indicate "FULL"; and
- Oxygen-generating canisters and CO2 sorbent in closed-circuit apparatus are new and capable of providing full-rated service.

If the SCBA or supplied air respirator does not pass the inspection, it must be removed from service and tagged for repair by an authorized service centre.

In addition, SCBA and supplied air respirators must be tested, both visually and functionally, by an authorized service centre at least every two years.

📖 HSE Practice 402: Inspection

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SECTION 900: WORKING WITH POWERED TOOLS

901 Working with Explosive Actuated Tools

STANDARDS:

1. Only employees trained in the operation of a particular explosive actuated tool are allowed to use it.

2. If the tool is equipped with protective guards, the protective guards must be used.

3. Employees required to operate explosive actuated tools repeatedly or for prolonged periods must wear hearing protection.

4. Explosive actuated tools must be used only in non-flammable environments.

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APPLYING THE STANDARDS:

Explosive actuated tools are normally used to connect conductors (ampacts) or fastening devices (e.g., screws or bolts) to materials such as concrete and steel. When planning to use explosive actuated tools, make sure consideration has been given to the proximity of co-workers. Always communicate with others in the vicinity.

Training for explosive actuated tools can be arranged through the Training Centre.

902 Working with Compressed Air Tools

STANDARDS:

1. Use of compressed air tools must be identified as a hazard during the job planning process.

2. Compressed air tools must be operated in accordance with the manufacturer's instructions and only with recommended attachments. DO NOT operate above the manufacturer's rating.

3. Only tools in good condition may be used. Hoses must be regularly checked for cuts, bulges and abrasions, and replaced if defective.

4. Air pressure must be released before connections are broken, unless the equipment has quick acting, self-closing connectors.

5. Air pressure to hoses must be turned off at the end of the working day.

6. Compressed air pressure must NEVER be:

    - Released toward yourself or another person; or

    - Used to clean off your clothing or your body.

7. Employees using portable air compressors must follow the manufacturers speculations and, if applicable, any written work procedures in place for the portable unit.

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APPLYING THE STANDARDS:

Keep your hands away from the operating switch when changing body or tool positions.

903 Working with Grinders and Metal Chop Saws

STANDARDS:

1. Only grinders equipped with properly adjusted protective shields may be used.

2. *During grinding and buffing operations employees must wear all necessary PPE (including proper hand, eye and face protection,).*

3. Employees using metal chop saws must wear hand, eye and face protection (e.g., safety glasses and a face shield).

4. Employees using grinders or metal chop saws must make sure all guards and shields are in place and follow safe operating procedures.

APPLYING THE STANDARDS:

Safe Operating Procedures

1. Disconnect the power source before adjusting the tool rest or changing the wheel.

2. Adjust the tool rest so that the upper edge is not below the centre line of the abrasive wheel, or more than 2 mm from the cutting surface.

3. Stand to one side of the grinder until the wheel reaches operating speed, and then begin grinding.

4. Each time the wheel *or blade* is changed, check the r.p.m. rating. DO NOT use a wheel *or blade* unless it has an r.p.m. rating that is as fast as the grinder or saw.

5. DO NOT use a wheel that has been dropped on a hard surface.

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6. DO NOT grind on the sides of an abrasive wheel unless it is designed for that use.

7. DO NOT use wet grinding wheels as they may become unbalanced or create soft spots in the grinding wheel.

8. When using a chop saw for an extended period of time, consider wearing a protective apron.

904 Working with Hydraulic Tools

STANDARDS:

1. Hydraulic tools must be operated in accordance with the manufacturer's instructions and safe operating procedures.

2. All exposed fittings and hoses must be examined before each use to make sure there are no visible defects.

3. Hydraulic pressure must be released before connections are broken unless the equipment has quick acting, self-closing connectors.

4. *Hydraulic tools must not be interchanged between a dielectrically tested and rated aerial unit and an unrated unit.*

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APPLYING THE STANDARDS:

Safe Operating Procedures

1. Keep your hands away from the operating switch when changing body or tool positions.

2. *Only qualified personnel who fully understands the hazards of hydraulics must check for pin hole leaks.*

    - *Check for pin hole leaks by passing a piece of cardboard or wood over the suspected area.*

    - *DO NOT check for pin hole leaks with your hands, as hydraulic pressure through a pin hole can easily cut through a rag, gloves and the skin underneath.* The pressure could inject the hydraulic fluid stream under your skin. HYDRAULIC FLUID INJECTED UNDER THE SKIN CAN BE FATAL.

905 Working with Vibrating Tools

STANDARDS:

1. Extended use of vibrating tools must be addressed as a hazard in the job planning process.

Employees required to use vibrating tools for an extended period of time must take the following safety precautions:

- Wear properly-fitting vibration-dampening gloves if the tool is not equipped with a vibration dampening feature;

- Keep wrists in the “neutral” position while using the tool; and

- Take a few short breaks every hour and massage hands to maintain circulation.

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APPLYING THE STANDARDS:

An example of extended use of vibrating tools is jack hammering concrete for more than one hour. Standard 2 does not normally apply when using tampers and ground rod pounders unless use is prolonged.

906 Working with Chain Saws

STANDARDS:

1. All employees required to operate chain saws must receive Chainsaw Basic training through Training and Development prior to operation.

2. Employees designated as first responders (i.e. dealing with trouble trees on lines) are required to receive Chainsaw Advanced training. Training and Development requires employees to complete Chainsaw Basic prior to receiving Chainsaw Advanced.

3. Chain saws must be operated *in accordance with the training received and shall be* adjusted and maintained in accordance with the manufacturer's specifications.

4. All employees using chain saws must wear a face shield, Class A ear muffs, safety boots or chainsaw boots, *and full-length leg protection as identified in the ATCO Electric tool catalogue.*

5. Employees must ensure that they have a #2 first aid kit with them at the location of chainsaw activities

6. All chain saws must be equipped with*: throttle interlock, chain catcher,* chain brake *and if available a low kick back chain must be used.*

7. Hydraulic-powered saws must be equipped *with a low* kick *back* chain *if available*.

8. Chain saws must not be operated from poles *or trees*.

9. Chain saws must not be operated above shoulder level, with the exception of the bucket work identified below.

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10. When operating a chain saw from a bucket, the operator must wear a protective chain saw jacket *as identified in the ATCO Electric tool catalogue.*

11. Where possible, the bucket shall be positioned so that a chainsaw cut can be made from below shoulder height. If this is not possible, workers cutting from the bucket must take caution to reduce additional risks for injury associated with kickback from cuts above shoulder height.

12. Chain saws must be turned off when ascending to or descending from a work location. The operator may warm up the chainsaw while still on the ground, prior to ascending to the work location.

13. The chain saw operator must not start the engine until in the immediate work area. *Chain brakes are to be applied when moving between locations.*

14. While the chain saw is running, no one is allowed within a 2-metre radius of the chain saw and operator.

15. The operator must hold the chain saw firmly with both hands when cutting. *The saw must not be operated at any time with only one hand.*

APPLYING THE STANDARDS:

- 🕮 Training Course – Chainsaw Basic
- 🕮 Training Course – Chainsaw Advanced
- 🕮 *ATCO Electric Tool Catalogue*

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Management Guide ATCO Electric	Protective Clothing and Safety Equipment	B19 1 of 3

A. PURPOSE

This Policy outlines responsibilities for employer and employee to obtain protective clothing and safety equipment, and the procurement and distribution of the clothing and equipment.

The protective clothing and safety equipment specified in this Policy is integral to Company safety systems protecting workers from the following potential affects:

- Burns
- Heat attenuation
- Vehicle impact (high visibility)
- Eye injury
- Foot injury
- Head Injury
- Frostbite
- Slips and Trips

Wearing the protective clothing also helps maintain the identifiable and beneficial image ATCO Electric employees have helped build among customers.

B. POLICY

ATCO Electric will provide the necessary protective clothing and safety equipment to the level that the Safety Standards Manual and field level hazard assessment prescribes. ATCO Electric will ensure employees: are aware of procedures for obtaining protective clothing appropriate to their job needs; receive training on the use; and have access to all necessary safety equipment.

Employees shall advise on, select from the Company catalogue, inspect, wear, care for, clean, arrange for repair, account for, and request replacement of protective clothing and safety equipment. Employees shall also report equipment or protective clothing that is in bad condition, may not withstand the necessary function, or has obvious defects.

Employees will pay 40% of the expense for protective footwear. Employees will pay 100% of the expense for 'against-the-skin' undergarments (e.g., boxer shorts, briefs, sport bras) which must be a minimum of 65% natural fibres (e.g., cotton or wool). Regarding repairs of FR clothing or protective footwear, ATCO Electric will pay for 100% of the expense.

C. ACCOUNTABILITIES

1. Employees covered by this policy will always wear protective clothing to ensure their ongoing safety and readiness for work.
2. The Company will maintain a Protective Clothing and Safety Equipment Steering Committee to:
    a. Sustain quality, functional requirements and specifications of protective clothing and safety equipment for entering into the Company's procurement system catalogue;
    b. Provide ongoing support for decisions related to the organizational alignment and application of the policy; and
    c. Maintain a website page on E-net to serve as a reference source and tool for viewing protective clothing and safety equipment materials.
3. Individual operating departments must annually budget for the capital and O&M expenses of adding and repairing protective clothing and safety equipment.
4. Supervisors and in-scope leaders will keep an up-to-date spreadsheet with the amount of protective clothing and safety equipment in possession of each worker assigned to their location.
    a. Employees will account for all clothing and equipment in September and in-scope leaders will forward a copy of this information and comments for review by their Sr. Mgr. and the Steering Committee before September 30 each year. *See Annual Inventory Form on http://enet/Support/HSE/FRC.htm.*
    b. Any employee unable to account for protective clothing and safety equipment recorded in their possession will report the occurrence to their Sr. Mgr. and replace the item(s) at their expense. *See Annual Inventory Form on http://enet/Support/HSE/FRC.htm.*
5. Protective clothing and safety equipment (except footwear, eyewear and 'against-the-skin' undergarments (e.g., boxer shorts, briefs, sport bras)) used by employees in the Company's work are limited to the items specified in the Company's clothing and tool catalogues.
6. Quality of protective clothing and safety equipment in possession of a worker must present observable protection and meet the minimum safety requirements of the manufacturer and ATCO Electric Safety Standards Manual.
7. Employees shall immediately return protective clothing and safety equipment (except footwear and eyewear) to the Company upon:
    a. Request by management
    b. Indications of surplus to requirements
    c. Finding irreparable damage during inspections
    d. Receiving clothing or equipment replacements
    e. Change to job function not requiring the clothing or equipment, or
    f. Termination of employment.

Management Guide ATCO Electric	Protective Clothing and Safety Equipment	B19 3 of 3

D. COMPLIANCE

This policy is pursuant with ATCO Electric's Safety Standards Manual (SSM), Section 300. Non-compliance of the policy risks contravention of the Occupational Health and Safety Act, Chapter 0-2, (Obligations of employers, workers, etc) for which ATCO Electric has the obligation to protect the health and safety of their workers as far as reasonably practicable.

Adherence to this policy is in accordance with Best Practice 001 Safety Leadership Planning, which clearly defines employee accountabilities for safety - in this case, barriers to hazards as identified in employees hazards assessment.

This table specifies protection required, approved items, procurement of items and responsibility for payment of the items. For additional details on protective clothing prescribed for specific positions, refer to ATCO Electric's Safety Standards Manual, Section 300.

TABLE 1

Protection	Approved Items	Procurement	*Expense Detail
Eye & Face	Glasses	Retail Vendors	
	Face Shields	Co. Catalogue & Inventory	
Foot	All seasonal footwear	Retail Vendors	Employee 40% Company 60%
Head	Hard Hats & Accessories	Co. Catalogue & Inventory	
Hand	Gloves, Mitts	Co. Catalogue & Inventory	
Body	All Clothing with the exception of 'against-the-skin' undergarments	Materials Management Co. Catalogue	
	Rain Jackets		
	Rain Pants (bibs)		
	Hard Hat Liners		
	Balaclavas		
	Vests		
	Shirts		
	Pants		
	Overalls (bibs)		
	Coveralls		
	Jackets		
	Repair Materials		
	Blast Suits	Retail Vendors	

***EXPENSE DETAIL (Company pays 100% unless otherwise noted)**

Approved by: BL / SP	Approval Date:	Expiry Date:
	August 2011	August 2013

APPENDIX A: Equipment Test and Service Schedule

ITEM	FREQUENCY (months)	STANDARD
Hot Sticks	36	IEEE 516-2003
Long Substation Switch Sticks*	36	IEEE 516-2003 Field test
Insulating Structure-Mounted Work Platform (diving board)	36	IEEE 516-2003
Insulated Transformer Gin	36	IEEE 516-2003
Load Break Tools	36	IEEE 516-2003
Voltage/Potential Detector	36	IEEE 516-2003
Insulated Aerial Device Upper Boom	12	CSA C225-00
Plastic Guard Equipment/ Rigid Coverup / Fibre Protective	12	ASTM F712-88 (2000) ULC D61229
Insulated Aerial Device Lower Boom Insert	12	CSA C225-00
Insulated Aerial Device Jib	12	IEEE 516-2003
Basket Liner	12	CSA C225-00
Insulated Aerial Device Hydraulic Oil	12	ASTM D877-02e1
Insulated Hydraulic Hose	12	IEEE 516-2003
Insulated Hydraulic Tool Handles	12	IEEE 516-2003
Live Line Jumpers	12	ASTM F496-02a
Rubber Line Hose & Covers	12	ASTM F478-92 (1999)
Rubber Blankets	12	ASTM F479-95 (2001)
Rubber Gloves Class 0	6	ASTM F496-02a
Rubber Gloves Class I	6	ASTM F496-02a
Rubber Gloves/Mitts Class III	6	ASTM F496-02a
Ground Chains*	12	*ASTM F2249-03*
SCBA & Supplied Air Respirators	24	CSA Z94.4-02
SCBA Air Replacement	6	CSA B339, B340

CONTACT THE LOCAL WAREHOUSE FOR THE APPROVED SERVICE SUPPLIER AND SHIPPING PROCEDURES

* Tested locally with portable test set

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ITEM	FREQUENCY Months	STANDARD
Gas Detectors (H_2S)	6, or as specified by manufacturer	Per manufacturer
Line Locators (transmitters and receivers)	As specified by manufacturer or if not working	Per manufacturer

APPROVED SERVICE SUPPLIER

Internal Mail
ATCO Gas
Service Centre
Calgary
Attn: Gary Ham
Phone: 403-245-7849/Fax: 403-245-7600
Email: gary.ham@atcogas.com

Postal/Shipping
ATCO Gas
1040 - 11 Ave SW
East Dock, Door #2
Calgary, AB
T2R 0G3
Attn: Gary Ham

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YUB-YECL-72

Reference: Line item – Transportation Equipment, YECL Application, page 9-51

- Replacement of Units 161, 163, 372, 674 and 675
- Purchase New Pole Trailer
- Purchase New Service Truck PLT Team Lead
- Purchase Zoom Boom Personnel Lift
- 4 Place Stringing and Pulling Trailer

Request:

(a) Please provide the replacement policy/criteria for vehicle replacement.

(b) Please provide any business cases for the purchase of new vehicles for each of the test years.

Response:

(a) Key considerations for the replacement of transportation equipment include the age, mileage and required costs to repair to acceptable working condition. Service vehicles are mechanically evaluated when they reach 170,000 kilometers and 7 years of age. If the vehicle is in good to fair mechanical condition it will continue to be utilized. For any vehicles that receive a poor mechanical condition rating, an estimate for necessary repairs is completed. The cost of repair, repair history and use of vehicle are reviewed in consideration of replacement.

(b) Please refer to the following for the business cases:

2013

- YUB-YECL-72 Attachment 1 – Diesel Powered Hydraulic Cable/Wire Puller
- YUB-YECL-72 Attachment 2 – New Stringing Trailer
- YUB-YECL-72 Attachment 3 – Unit 674 Replacement
- YUB-YECL-72 Attachment 4 – Unit 675 Replacement

- YUB-YECL-72 Attachment 5 – Unit 161 Replacement
- YUB-YECL-72 Attachment 6 – Unit 163 Replacement
- YUB-YECL-72 Attachment 7 – New Service Truck
- YUB-YECL-72 Attachment 8 – Unit 372 Replacement
- YUB-YECL-72 Attachment 9 – Zoom Boom

2014

- YUB-YECL-72 Attachment 10 – Forklift Replacement
- YUB-YECL-72 Attachment 11 – Unit 777 Replacement
- YUB-YECL-72 Attachment 12 – Unit 887 Replacement
- YUB-YECL-72 Attachment 13 – Unit 780 Replacement
- YUB-YECL-72 Attachment 14 – Unit 164 Replacement

2014

- YUB-YECL-72 Attachment 15 – Unit 989 Replacement
- YUB-YECL-72 Attachment 16 – Unit 747 Replacement
- YUB-YECL-72 Attachment 17 – Unit 851 Replacement
- YUB-YECL-72 Attachment 18 – Unit 882 Replacement
- YUB-YECL-72 Attachment 19 – Unit 955 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Purchase Diesel Powered Hydraulic Cable/Wire Puller

The Yukon Electrical Company Limited
An ATCO Company

Title: **Purchase Diesel Powered Hydraulic Cable/Wire Puller**

Summary:

Yukon Electrical's power system construction and maintenance team requires the use of a specialized puller. In the past, this service was contracted out or one would be rented from a contractor as required. Now this work is largely being performed in house and constant access to the puller for emergency and planned needs is required. In addition the preferred contractor's puller is sent outside the territory when not in use and is increasingly hard to access.

Project Description:

Purchase a used puller to have in house that is able to pull both overhead wires and underground cables

Project Cost:

2013 – $35,000

Business and Technical Drivers

Business Drivers:

Specialized tool now required in house and ability to better control costs associated with renting unit.

Technical Drivers:

Difficulty to access contractor's equipment. Increased requirement for use of specialized puller.

Alternatives:

Alternative # 1: Continue to utilize the services of the contractor. This alternative is difficult due to the limited access to the contractor.

Alternative # 2: Rent a puller and perform the work in house. This option can be costly and is also dependent on the availability of the equipment as there are none in the Yukon for rent.

Alternative # 3: Purchase a used diesel powered hydraulic cable/wire puller suitable to Yukon Electrical's requirements. This is the most cost effective and attractive alternative that gives Yukon Electrical unlimited access to the equipment.

Alternative # 4: Purchase a new diesel powered hydraulic cable/wire puller suitable to Yukon Electrical's requirements. A new puller costs approximately $145,000.

Recommendation:

Purchase a used diesel powered hydraulic cable/wire puller.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Purchase New Stringing Trailer

The Yukon Electrical Company Limited
An ATCO Company

Title: **Purchase New Stringing Trailer**

Summary:	Due to the increased amount of capital work required, a stringing trailer is needed to enable the line crews to perform construction work and increase the productivity of the construction team.
Project Description:	Purchase a trailer suitable to haul wire reels and poles. The dual purpose trailer will provide a more versatile and cost effective piece of equipment.
Project Cost:	2013 – $30,000

Business and Technical Drivers

Business Drivers:	This is a specialized tool required in house and will provide better financial control as this item is dual purpose and expandable to accommodate a tensioner system.
Technical Drivers:	Tool required for crew to perform construction work.
Alternatives:	Alternative # 1: Continue to use wire reel stands temporarily mounted to a trailer. This is not a viable alternative since there are now two line crews that require the use of this equipment to perform construction work. Also with existing equipment Yukon Electrical is not able to complete tension stringing in a live line application. Alternative # 2: Rent a stringing trailer. Currently there are no companies in the Yukon that rent stringing trailers. Alternative #3: Purchase a new stringing trailer.
Recommendation:	Purchase a new stringing trailer to enable the second line crew to perform construction work.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 674 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 674 Replacement**

Summary:	Unit 674 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 674, a 2006 Dodge ¾ Ton 4X4 Extended Cab, in 2013 with a new vehicle of a similar size that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2013 – $70,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle 7 years old with 199,620 km. It has been identified as overweight in accordance with NSC. Current unit has encountered reliability issues in the past couple of years.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Vehicle weight has been unloaded to comply with NSC, however it has restricted the use of the vehicle as it is no longer fit for a Powerline Technician. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 675 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 675 Replacement**

Summary:	Unit 675 is in need of replacement since the vehicle was involved in collision and written off by insurance assessment officer.
Project Description:	Approval required to replace unit 675, a Dodge ¾ Ton Extended Cab 4X4 with a ½ Ton 4X4 in 2013. Unit 675 is utilized by a Field Service Representative and is no longer required to be a large service vehicle. The new vehicle will have valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The vehicle was involved in a car accident in 2012 that did significant damage to the vehicle that it was no longer drivable and deemed not repairable. The vehicle is no longer in service.
Project Cost:	2013 – $30,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement since the current unit is not operational. Yukon Electrical requires this unit in order to deliver service to the community.
Technical Drivers:	The vehicle was written off by the insurance adjusters and is currently not in service.
Alternatives:	Alternative #1: The only alternative is to replace the existing unit since it is no longer operational.
Recommendation:	Purchase a replacement unit of a adequate size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 161 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 161 Replacement**

Summary:	Unit 161 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Approval required to replace unit 161, a 2001 Ford ¼ Ton 4X4, in 2013 with a new vehicle of a similar size that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2013 – $30,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle 12 years old with 197,010 km and in poor mechanical condition. Current unit has encountered reliability issues in the past couple of years.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 163 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 163 Replacement**

Summary:	Unit 163 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Approval required to replace unit 163, a 2001 Chevrolet ¾ Ton 4X4, in 2013 with a new vehicle of a similar size that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2013 - $70,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit. This vehicle is used in a remote community and reliability is also a concern.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle is 12 years old with 218,157 km. The vehicle is also currently not in compliance with NSC. Current unit has encountered reliability issues in the past couple of years.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Unable to remove enough weight to comply with NSC. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

New Service Truck

The Yukon Electrical Company Limited
An ATCO Company

Title: **New Service Truck**

Summary:	Yukon Electrical is seeking to purchase a new ½ Ton Truck for the Powerline Technician Team Lead of the second line crew to enable them to perform construction work simultaneously with the first line crew.
Project Description:	Yukon Electrical is purchasing a new ½ Ton Truck to enable the Powerline Technician Team Lead to carry out his duties for the second line crew. These duties include carrying tools, materials and the line crew to and from job sites.
Project Cost:	2013 – $30,000

Business and Technical Drivers

Business Drivers:	Increasing Vehicle Fleet size to meet increase in Yukon Electrical's planned capital work. Increase the productivity of the construction team.
Technical Drivers:	A new vehicle is required due to the increase in construction staff associated with the increase in capital work Yukon Electrical will be performing.
Alternatives:	Alternative # 1: Continue to utilize a single truck for both line crews. This alternative is not viable given there are now two construction line crews and they require to work separate and in different locations. Alternative # 2: Purchase a new ½ Ton Truck for the PLT Team Lead of the second line crew.
Recommendation:	Purchase a new ½ Ton Truck for the second line crew.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 372 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 372 Replacement**

Summary:	Unit 372 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Approval required to replace unit 372, a 2003 Dodge 3500 1 Ton 4X4, in 2013 with a new vehicle of a similar size that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2013 - $80,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle is 9 years old with 238,898 km and in poor overall mechanical condition. Current unit has encountered reliability issues in the past couple of years.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. The Electrical technologists travel to all rural communities in all weather conditions and need a reliable vehicle. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Purchase Zoom Boom

The Yukon Electrical Company Limited
An ATCO Company

Title: **Purchase Zoom Boom**

Summary:	Purchase Zoom Boom for Watson Lake Diesel Plant.
Project Description:	Yukon Electrical requires a Zoom Boom variable reach forklift for its Watson Lake Diesel Plant to allow the plant operators to perform maintenance on the areas of the plant not reachable from the ground. In the past scaffolding was used and was less efficient and also posed a safety concern as the scaffolding cannot reach all areas were work is required. The Zoom Boom will comply with safety regulations and give the staff more flexibility performing their duties.
Project Cost:	2013 – $49,000

Business and Technical Drivers

Business Drivers:	The plant operators are unable to perform various tasks with scaffolding and ladders. The Zoom Boom provides a safer and a more secure way to carry out above ground elevation work. Provides compliance with BP 503-Working at Heights.
Technical Drivers:	Gives the plant operators the ability to lift heavy engine parts when repairing/replacing engines, work on exhaust equipment directly above units and plant lighting that is on 25 ft ceiling.
Alternatives:	Alternative # 1: Rent a Zoom Boom for the work, however currently there is no access to one in Watson Lake. Alternative # 2: Continue using scaffolding and ladders to perform these duties. This is not a viable alternative since there are a number of tasks where scaffolding and ladders are not safe. Alternative # 3: Purchase a Zoom Boom for the Watson Lake plant.
Recommendation:	Purchase a Zoom Boom for the Watson Lake plant.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Forklift Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Forklift Replacement**

Summary:	Yukon Electrical Whitehorse Service Complex warehouse requires replacement of existing 1994 Cark 2 wheel drive forklift.
Project Description:	Replacement forklift required to perform loading and unloading of freight and is required to operate outdoors in all weather conditions. The current forklift is near end of its operational life. In addition, Yukon Electrical intends to replace the existing 2 wheel drive forklift with a 4 wheel drive forklift to provide a more stable operation in the Service Complex yard in all weather conditions.
Project Cost:	2014 – $90,000

Business and Technical Drivers

Business Drivers:	Forklift required on an ongoing basis for operational purposes and specific to our material handling requirements.
Technical Drivers:	The new forklift will have 4 wheel drive which is capable of operating safely in all weather conditions as well as operating indoors on pallet racking system. The existing 2 wheel drive forklift is regularly stuck in the Whitehorse Service Complex yard.
Alternatives:	Alternative # 1: Continue to repair and use current 2 wheel drive forklift. This could result in further incidents of machine being stuck in yard during winter and inefficiency due to down time of unit. Alternative # 2: Purchase a new 4 wheel drive forklift for the Whitehorse Service Complex.
Recommendation:	Purchase a new 4 wheel drive forklift for the Whitehorse Service Complex.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 777 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 777 Replacement**

Summary:

Unit 777 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.

Project Description:

Yukon Electrical is seeking approval to replace unit 777, a 2007 Dodge ¾ Ton 4X4, in 2014 with 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

This unit is based in Haines Junction and will be used for regular service trips, repairing streetlights and brushing in Haines Junction, Destruction Bay, Burwash and Beaver Creek.

Project Cost:

2014 – $230,000

Business and Technical Drivers

Business Drivers:

A bucket truck is required on a regular basis to perform maintenance of overhead power systems. Opportunity to decrease maintenance and operating costs related to the old unit.

Technical Drivers:

Routine and emergency work could be completed in a timelier and cost effective manner with this unit. Unit 777 is 7 years old and has approximately 250,000 km. The age of the unit is a primary concern since it is used in remote areas and issues with reliability can be more serious in the harsh winter months.

Alternatives:

Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. The vehicle is used in remote areas, which poses an even greater safety concern. Powerline Technician in Haines Junction will continue to come to Whitehorse to utilize bucket truck for use in Haines Junction, Destruction Bay, Burwash and Beaver Creek.

Alternative # 2: Purchase a replacement 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

Recommendation:

Purchase a replacement 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 887 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 887 Replacement**

Summary:

Unit 887 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.

Project Description:

Yukon Electrical is seeking approval to replace unit 887 with 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

This unit will be used for regular service trips, repairing streetlights and brushing in Whitehorse, Carcross, Carmacks, Teslin, Marsh Lake, Tagish, Pelly, Stewart, Keno and Ross River.

Project Cost:

2014 – $230,000

Business and Technical Drivers

Business Drivers:

A bucket truck is required on a regular basis to perform maintenance of overhead power systems. Opportunity to decrease maintenance and operating costs related to the old unit.

Technical Drivers:

Routine and emergency work could be completed in a timelier and cost effective manner with this unit. Existing bucket truck in Whitehorse is unable to keep up with demand. Unit 887 will be 7 years old and has approximately 200,000 km.

Alternatives:

Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Continue to provide service to Whitehorse, Carcross, Carmacks, Teslin, Marsh Lake, Tagish, Pelly, Stewart, Keno and Ross River with single bucket truck.

Alternative # 2: Purchase a replacement 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

Recommendation:

Purchase a replacement 5500 Quad Cab 4x4 c/w TL38 service body and bucket.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 780 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 780 Replacement**

Summary:	Unit 780 is a small digger derrick that is in need of replacement because of the age, operational efficiency and high costs of maintenance.
Project Description:	Yukon Electrical will engage ATCO Electric fleet management to design and obtain quotes for replacement of unit 780 – 1993 Digger Derrick. The existing unit is unable to haul a trailer with more than one pole and the GVWR is too light to be a front line digger.
Project Cost:	2014 – $375,000

Business and Technical Drivers

Business Drivers:	A digger derrick is essential piece of utility equipment that is used in the power line construction and maintenance activities such as setting poles, hanging transformers, installing and replacing street lights, and carrying poles.
Technical Drivers:	Unit 780 is a small digger derrick and the vehicle GVWR is too light to haul a trailer with more than one pole. As construction and maintenance requirements have grown, the unit's limited capability has been realized as detrimental to efficient utilization of two Yukon Electrical line crews. The working capability of the unit is too limited. Unit 780 will be 21 years old with approximately 100,000 kms.
Alternatives:	Alternative # 1: Continue to use small digger derrick. This results in narrowed work or projects as it can only complete a few tasks required of a digger derrick. Also, the vehicle is 21 years old and maintenance required to maintain adequate performance will increase. Alternative # 2: Purchase a new replacement digger derrick.
Recommendation:	Purchase a new replacement digger derrick.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 164 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 164 Replacement**

Summary:	Unit 164 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 164, a 2001 Chevrolet ¾ Ton 4X4 Extra Cab, in 2014 with a vehicle of a similar size that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2014 – $70,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit. This vehicle is used in a remote community where the reliability is imperative.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and vehicle will be 13 years old with approximately 220,000 km. Current unit has encountered reliability issues in the past couple of years.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 989 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 989 Replacement**

Summary:	Replace unit 989 – Live Line Bucket Truck since the unit is no longer able to perform live line work, its primary purpose, and is nearing end of life.
Project Description:	Yukon Electrical will engage ATCO Electric fleet management to design and obtain quotes for replacement of unit 989 – 1995 Live Line Bucket Truck. The current live line bucket truck is unable to perform live line work due to the age and deterioration of the unit's insulation and boom. A new unit is required to fulfill Yukon Electrical's requirement to perform live line maintenance.
Project Cost:	2015 – $450,000

Business and Technical Drivers

Business Drivers:	Maintain ability to do live line work as an alternative to planned outages. This is a key activity for Yukon Electrical to provide customers in reducing outages and maintaining customer service. Having a planned outage for an entire subdivision or large area of the distribution system to change one pole is avoidable.
Technical Drivers:	Conductivity tests show the insulating is deteriorating, holding valves are failing on a regular basis and require repairs, the boom requires significant maintenance and is starting to fail, and the aerial unit is nearing the end of its operational life. The vehicle unit is a 1995 unit that is also needing regular maintenance and will soon receive a 'poor' mechanical rating if deterioration continues.
Alternatives:	Alternative # 1: Continue to use, maintain and repair unit 989. The mechanical condition of the truck is in moderate to poor condition. The live line boom is tested and rated for required work, but continues to degrade and will soon require significant repair work. The boom repair work would result in the unit being transported down south to a repair shop. This would leave Yukon Electrical without a live line bucket truck for months and the same mechanical issues with the 1995 truck and drive train if the boom was repairable. Alternative # 2: Purchase a new replacement live line bucket truck.
Recommendation:	Purchase a new replacement live line bucket truck.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 747 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 747 Replacement**

Summary:	Unit 747 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 747, a 1997 Chevrolet ½ Ton 4X4 in 2015. The replacement vehicle will be designed as a 1 Ton 4X4 with a service body. The new vehicle will have a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR) for its purpose. The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2015 – $100,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle will be 18 years old with approximately 270,000 km. Weight restrictions of NSC have required Yukon Electrical to standardize 1 Ton units as the minimum GVWR.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of a adequate size.
Recommendation:	Purchase a replacement unit of a adequate size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 851 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 851 Replacement**

Summary:	Unit 851 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 851, 1999 Dodge ¾ Ton 4X4, in 2015 with a 1 Ton 4X4 vehicle that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2015 – $100,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle will be 16 years old with approximately 235,000 km. Weight restrictions of NSC have required Yukon Electrical to standardize 1 Ton units as the minimum GVWR.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of a similar size.
Recommendation:	Purchase a replacement unit of a similar size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 882 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 882 Replacement**

Summary:	Unit 882 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 882, 2006 GMC Sierra ¾ Ton 4X4, in 2015 with a 1 Ton 4X4 vehicle that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with service bodies added to the cab and chassis.
Project Cost:	2015 – $100,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle will be 7 years old with an estimated 118,000 km. Weight restrictions of NSC have required Yukon Electrical to standardize 1 Ton units as the minimum GVWR.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle will have no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of adequate size.
Recommendation:	Purchase a replacement unit of adequate size.

The Yukon Electrical Company Limited
An ATCO Company

Business Case

Unit 955 Replacement

The Yukon Electrical Company Limited
An ATCO Company

Title: **Unit 955 Replacement**

Summary:	Unit 955 is in need of replacement due to the age and mileage of the vehicle. Purchasing a new unit would also increase safety, abide by the National Safety Codes (NSC) and decrease maintenance cost.
Project Description:	Yukon Electrical is seeking approval to replace unit 955, 2000 Chevrolet ½ Ton 4X4 Extended Cab, in 2015 with a 1 Ton 4X4 new vehicle that has a valid warranty, the most current safety features and adequate gross vehicle weight rating (GVWR). The replacement vehicle will be equipped with a service body added to the cab and chassis.
Project Cost:	2015 – $100,000

Business and Technical Drivers

Business Drivers:	Vehicle/Fleet Replacement. Opportunity to decrease maintenance and operating costs related to the old unit.
Technical Drivers:	Safety is a primary concern of Yukon Electrical and the vehicle will be 15 years old with approximately 240,000 km. Weight restrictions of NSC have required Yukon Electrical to standardize 1 Ton units as the minimum GVWR.
Alternatives:	Alternative # 1: Continue to repair and maintain the vehicle to the Commercial Vehicle Maintenance Standards. The vehicle has no warranty and there is no guarantee that maintenance will provide reliable operation. Alternative # 2: Purchase a replacement unit of adequate size.
Recommendation:	Purchase a replacement unit of adequate size.

YUB-YECL-73

Reference: Line item – Whitehorse Service Complex Pole Storage, YECL Application, page 9-51

Environmental requirement to get the poles off the ground.

Request:

Please provide more detailed information on the projected cost of $150,000.

Response:

Please refer to YUB-YECL-61 Attachment 2 for a breakdown of the project cost of $150,000. The costs for the standard metal pole bunks and hardware are forecast to be $100,000 and the cost for installation is forecast to be $50,000.

YUB-YECL-74

Reference: Line item – Destruction Bay Unit #3 Replacement, YECL Application, page 9-54

Purchase new unit complete with new manufacturer supplied and sized, radiator, exhaust, and heat exchanger. Remove existing unit, install new unit and supplied devices, integrate unit into electrical supply and control systems, connect unit into waste heat and fuel systems.

Request:

Please provide the reasons as to why this unit is being replaced.

Response:

Destruction Bay Unit #3, as of December 2012, has 97,170 hours and is on schedule for a major overhaul at 102,761 hours. Based on yearly operating hours, this unit is forecast for a major overhaul in 2014. Yukon Electrical has determined that life extensions performed on units in excess of 100,000 operational hours are not prudent as the unit may not operate reliably with these excessive operational hours. A generator with these operating hours is at the end of its life.

YUB-YECL-75

Reference: Line item – Destruction Bay Programmable Logic Controller Upgrade, YECL Application, page 9-54

Replacement of circa 1982 IDEC PLC as this control equipment is no longer supported or available from the manufacturer. The software driver is not compatible with the next generation System C and Data Acquisition (SCADA) program. Includes design and procurement of control equipment and panels as well as on-site installation and commissioning of the equipment.

Request:

Have all the other plants replaced their PLC's to work with the new SCADA system?

Response:

Old Crow, Beaver Creek, Destruction Bay, Teslin and Stewart Crossing are the generating facilities that still house IDEC PLCs.

Beaver Creek PLC is scheduled for replacement in 2013. Destruction Bay is scheduled for replacement in 2014. Old Crow is scheduled for replacement in 2016. Teslin and Stewart Crossing will be completed some time after 2016.

YUB-YECL-76

Reference: Line item – Watson Lake Replace ABB 5HK Breakers, YECL Application, page 9-55

Current breakers are at the end of life and obsolete technology. Replace existing breakers with vacuum breakers and install them into existing cells.

If there are five breakers to be replaced at $45,000 each, the projected cost would be $225,000.

Request:

(a) Confirm the number of breakers that need to be replaced.

(b) Are any of the present breakers in immediate danger of failure?

(c) Do the present breakers present a safety hazard to the employees?

Response:

(a) There are eight breakers in total to be replaced: six generator unit breakers and two power plant bus feeder breakers.

(b) No. The Arc Extinguishing Chutes in the breakers were inspected during regular maintenance shutdowns. Dielectric testing has confirmed the insulation is intact, except for small cracks, and is able to continue to operate as designed. However, the Arc Extinguishing Chutes have asbestos-lined material that has cracked and flaking occurs during operation of the breaker. There is no reliable method to predict if and when the breaker will fail.

(c) Yes. The concern is that the flaking asbestos becomes air borne during operation of the breakers. Asbestos is a known carcinogen.

YUB-YECL-77

Reference: Line item – Stewart Crossing Plant Improvements, YECL Application, page 9-55

General improvements including control system upgrades as well as building heating improvements. This will improve reliable operation of the generator and improve the energy efficiency of the building.

This plant is now tied into the grid and is now a standby plant.

Request:

Please explain the control system upgrades required if the Stewart Crossing Plant is now a standby plant. Please provide the current reliability metrics and the forecast improved reliability metrics.

Response:

The control system upgrade will allow Yukon Electrical to synchronize the Stewart Crossing Plant to the grid. Currently the community has a complete outage to transfer from the power supply of the Stewart Crossing Plant to the Yukon Interconnected System. This control system upgrade will reduce the outages to the community by 50% for any outages that resulted in disconnection from the Yukon Interconnected System and operation of the standby plant. Please refer to YUB-YECL-77 Attachment 1 for reliability metrics.

The Yukon Electrical Company Limited
Reliability Metrics for Stewart Crossing 2008-2012

Year	Service Area	CEA Coding	Interruptions	SAIFI	SAIDI	CAIDI	IOR
2008	581 Stewart Crossing	Loss of Supply - Yukon Energy	4	4.13	0.40	0.10	0.999954
2008	**581 Stewart Crossing**	**SERVICE AREA TOTAL**	**4**	**4.13**	**0.40**	**0.10**	**0.999954**
2009	581 Stewart Crossing	Lightning	1	1.03	0.13	0.13	0.999985
2009	581 Stewart Crossing	Loss of Supply - Yukon Energy	1	1.03	0.08	0.08	0.999991
2009	581 Stewart Crossing	Trees	1	0.07	0.12	1.75	0.999987
2009	**581 Stewart Crossing**	**SERVICE AREA TOTAL**	**3**	**2.13**	**0.33**	**0.16**	**0.999962**
2010	581 Stewart Crossing	Foreign Interference	1	0.14	0.98	6.83	0.999889
2010	581 Stewart Crossing	Loss of Supply - Yukon Energy	6	6.64	1.16	0.18	0.999867
2010	**581 Stewart Crossing**	**SERVICE AREA TOTAL**	**7**	**6.79**	**2.14**	**0.32**	**0.999756**
2011	581 Stewart Crossing	Defective Equipment	1	2.33	12.59	5.40	0.998563
2011	581 Stewart Crossing	Loss of Supply - Yukon Energy	6	7.53	15.43	2.05	0.998239
2011	581 Stewart Crossing	Scheduled	3	1.63	1.38	0.84	0.999843
2011	581 Stewart Crossing	Trees	2	1.20	7.94	6.62	0.999093
2011	**581 Stewart Crossing**	**SERVICE AREA TOTAL**	**12**	**12.70**	**37.33**	**2.94**	**0.995738**
2012	581 Stewart Crossing	Defective Equipment	2	0.74	6.79	9.17	0.999227
2012	581 Stewart Crossing	Loss of Supply - Yukon Energy	3	4.59	12.40	2.70	0.998589
2012	**581 Stewart Crossing**	**SERVICE AREA TOTAL**	**5**	**5.33**	**19.19**	**3.60**	**0.997815**

YUB-YECL-78

Reference: Line item – Ross River Replace ABB 5HK Breakers, YECL Application, page 9-55

Request:

(a) Is the present breaker in immediate danger of failure?

(b) Does the present breaker present a safety hazard to the employees?

Response:

(a) No. The Arc Extinguishing Chutes in the breakers were inspected during regular maintenance shutdowns. Dielectric testing has confirmed the insulation is intact, except for small cracks, and is able to continue to operate as designed. However, the Arc Extinguishing Chutes have asbestos-lined material that has cracked and flaking occurs during operation of the breaker. There is no reliable method to predict if and when the breaker will fail.

(b) Yes. The concern is that the flaking asbestos becomes air borne during operation of the breakers. Asbestos is a known carcinogen.

YUB-YECL-79

Reference: Line item – Miscellaneous O/H Services – Various Subdivisions, YECL Application, page 9-56

Capital expenditures required for the connection of new residential and commercial customers in Yukon Electrical's service area in compliance with Terms and Conditions. Any new extension (driven by a customer) that is under $25k is included in this.

Request:

Please provide the details as to how the projected expenditure was determined for each of the test years.

Response:

Yukon Electrical has determined its new extension capital forecast, including the Miscellaneous O/S Services, based on the knowledge it has of areas of development within its service areas as well as based on historical customer additions. New extensions are, on average, 75-80% funded by customer contributions. The net investment for the New Extension Category, including Miscellaneous O/S Services, is as follows:

		2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast
New Extensions	Schedule 9.1, L.10	6,078	4,919	5,149	5,307	5,570
Customer Contributions *		(5,149)	(3,097)	(3,903)	(4,320)	(4,160)
Yukon Electrical Net Investment		929	1,822	1,246	987	1,410

* Total contributions as per Schedule 8.12, L.3, less contributions received for Street Lights.

YUB-YECL-80

Reference: Depreciation, YECL Application, page 7-1

The depreciation rates used to calculate actual 2008 through 2012 depreciation expense were developed using the Board-approved depreciation parameters form Yukon Electrical's last General Rate Application.

Request:

(a) Please provide the terms of reference and the direction given by YECL to Gannett Fleming Inc. to undertake and the need for the depreciation study.

(b) Why is there a need to change YECL's depreciation study?

Response:

(a) Gannett Fleming was retained by Yukon Electrical in November 2012 to complete a full and comprehensive depreciation study. Gannett Fleming was also asked to research and provide an assessment of the reasonableness of including a request for the re-instatement of net salvage percentages into the depreciation rate calculations. There were no formal contractual documents or terms of reference.

(b) As stated in YUB-YECL-88(a), depreciation studies are typically completed every 3 to 5 years. Yukon Electrical's last depreciation study was submitted in its 2008-2009 GTA and was based upon data as of December 31, 2007. Yukon Electrical's submitted depreciation study is based upon data as of December 31, 2011. As detailed in Yukon Electrical's 2008-2009 GTA, Schedule 8.5, line 2, the 2007 year-end balance was $117M. As detailed in Yukon Electrical's current GTA, Schedule 8.5, line 2, the 2011 year-end balance was $155M with the 2015 year-end balance expected to be $229M. This represents an approximate 32% increase in property, plant and equipment from the 2007 data represented in Yukon Electrical's last depreciation study to the 2011 data represented in Yukon Electrical's current depreciation study. Furthermore, the year-end balance as of 2015 represents approximately a 96% increase from the 2007 year-end balance. In light of this significant amount of capital activity, Yukon Electrical determined that a detailed review and study was necessary to ensure an accurate recovery of its capital assets.

In addition, as detailed in Section 7, page 7-1, lines 10-14, Yukon Electrical is proposing to change the method of depreciation for diesel generation from a mass property approach to a life span approach. This change will allow for more accurate diesel generation depreciation rates.

In addition to the above noted issue driving the need for the depreciation study, Yukon Electrical also believes it is important for all parties to understand the following broader picture changes that have occurred in the Yukon since Board Order 2009-02.

The first issue that has changed since Board Order 2009-02 is that sending the right price signal to customers has taken on added importance as a result of diesel generation once again being on the margin in the Yukon. As the Board is aware, price signals that reflect the full cost to serve customers were discussed as part of the 2010 Yukon Electrical and Yukon Energy Joint Phase II Rate Application. While a large amount of the rate design discussion centered on economy and efficiency principles within the rate design of runoff rates and what exactly was meant by the term "economy and efficiency", Yukon Electrical notes the following statements in Board Order 2010-13 (paragraphs 196-197):

> The Board has considered the views of all the Parties and notes that there clearly is no consensus on this issue. However, it is clear that the Companies agree that in the past, economy and efficiency has been linked to the incremental cost of diesel generation.
>
> In terms of pricing signals, the Board is of the view that the best pricing signals to customers are those prices that reflect the full cost to serve those customers. Arguments on incremental cost of diesel generation, or what portion of the incremental cost of diesel generation should be reflected in the runoff rates should take a distant backseat to the proper alignment of costs to revenues for each rate class. Once rebalancing has occurred for the rate classes, then issues relating to runoff can be examined in greater detail.

While Yukon Electrical recognizes the above statements were in the context of setting runoff rates, it is for this exact reason of prices reflecting the full cost to serve customer that Yukon Electrical is requesting to once again collect negative net salvage as part of its revenue requirement.

A second large change since Board Order 2009-02 has been the development and inclusion in this Application of the Joint Yukon Electrical and Yukon Energy Demand Side Management (DSM) program. This program will promote energy conservation and will result in lower energy consumption. It is Yukon Electrical's position that it is counter intuitive to be investing in this DSM program while, at the same time, not sending the right price signal by not fully charging current customers for the cost to provide electric service; namely the cost associated with net salvage.

A third large change since Board Order 2009-02 has been the cessation of collection of net salvage resulting in Yukon Electrical falling considerably behind in its required recovery of the funds for future removal of assets. In the 3 year period from 2009 through 2011, an increase in the amount of Future Removal and Site Restoration (i.e. FRSR) deficiency transfer from current users of the Yukon Electrical utility assets to future rate-payers of $7.9 million has accrued to a total balance of over $12 million. It is noted that this significant increase in transfer to future rate-payers is caused by two significant forces. Firstly, the retirement costs associated with assets that have retired over the past 3 year period have drawn down the FRSR by over 6.2%[1] of the balance that existed at December 31, 2008. However, this draw down of the FRSR was caused by retirements of only approximately 3% of the plant in service as at December 2008[2]. In other words, the FRSR balance is drawing down at approximately twice the rate of the asset retirement activity of the plant in service balance that existed at December 31, 2008.

The second cause of the significant increase in the accumulated FRSR deficiency is the fact that older vintages of assets are now 3 years closer to expected retirement, providing less time for these vintages to recover the FRSR deficiency. While approximately 3% of the investment in plant in service as of 2008 has retired over the period from 2009 through 2011, this pace of retirements is expected to significantly increase in future years, which will require significantly increased amounts of cost of removal funding. For example, over the past 16 years, 4 diesel generating units have been removed and retired from service. However, over the next 3 year period 7 units will require replacement due to age and condition. As such, the pace of retirements will significantly increase over the next few years.

[1] Calculated by comparing the 2008 FRSR balance of $4,688,112 to the 2012 balance of $4.395,151
[2] Based on2009 through 2012 retirement transactions of $3.3 million compared to the 2008 plant in service balance of $115.7 million

Gannett Fleming has advised that the level of accumulated FRSR deficiency will continue to increase at an increasingly rapid pace in future years, if FRSR funding is not re-instated into the deprecation calculations. As noted above there are two independent forces that are causing increases in the amount of the deficiency, that will cause the deficiency to grow at an exponential rate, as witnessed over the past 3 year period. The inter-generational inequity of the current process as mandated by the Board in Decision 2009-02 has already caused future rate-payers to bear $7.9 million of additional burden, and continuation of this practice will see this burden increase by exponential amounts in future years.

The concept of inclusion of net salvage provisions into the depreciation rate calculations has been a topic of debate in many regulatory jurisdictions across Canada since the issuance of the YUB Board Decision 2009-02. As indicated in the Additional Evidence of Larry Edwin Kennedy filed with the current Yukon Electrical Application, this topic has received considerable attention in the depreciation rate filings in many jurisdictions. However, notwithstanding the significant amount of regulatory debate, the inclusion of net salvage percentages in the depreciation rate calculations continues to be widely accepted throughout Canada and North America. Furthermore, the topic of re-instatement of net salvage into depreciation rate calculations has been specifically discussed in hearings in British Columbia in 2011, in which the BCUC specifically allowed FortisBC Energy Inc. to re-instate collection of net salvage as part of their depreciation rate calculations. As stated by the BCUC in FortisBC Energy's 2012-2013 Revenue Requirements and Rates Decision, dated April 12, 2012, pages 83-84:

> The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period. Using a "pay as you go system" to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.

While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.

For the above reasons, Yukon Electrical is of the view that the completion of an updated depreciation study was necessary and appropriate.

YUB-YECL-81

Reference: Depreciation, YECL Application, page 7-1

For this depreciation study, Yukon Electrical has incorporated the usage of a life span analysis (similar to hydro generation) for each of its diesel generation locations. This will allow for more accurate depreciation rates for diesel generation facilities.

Request:

(a) Please describe and explain the method used to determine the depreciation expense for diesel generation facilities in prior YECL applications.

(b) Please explain lifespan analysis.

Response:

(a) In prior depreciation studies, the diesel generation facilities were depreciated using group depreciation methods with the use of an average service life estimate combined with an estimated retirement pattern (Iowa curve shape) on an account by account basis. In this manner the assets within each account are depreciated based on the expected average service life based on physical factors such as wear and tear, exposure to the elements, technology, etc. As such, the depreciation rates did not specifically consider economic factors on the facility as a whole that are now considered as part of the life span analysis.

(b) Long life assets such as electric generation plants are restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also, and to a much greater extent, by economic forces of retirement such as changes in demand and capacity, environmental factors, and alternative sources of generation. Generally, environmental forces of retirement will be the dominate retirement force than physical forces of retirement. In Yukon Electrical's situation, it is expected that economic forces of retirement will be the dominant force of retirement. As such, Gannett Fleming recommends the use of Life Span in the development of depreciation rate for electric generation plant.

The concept referred to with the terms "Life span", "economic life" or "economic planning horizon" or "truncation date" (which have similar meaning within

depreciation literature) is the key parameter used to set appropriate depreciation rates that accurately reflect the annual consumption in service value when nonphysical forces of retirement are probable. Appropriate depreciation rates also help to ensure that both long term generational equity and a reasonable opportunity for the recovery of investment are achievable.

The use of Life span in the calculation of depreciation rates introduces the concept of Terminal or final retirements into the calculation to represent those retirements described by the truncation of the interim survivor curve at the truncation date. The following diagram provides an illustration of the concept of terminal retirement in the calculation of the estimated average service life. In this illustration a life span date of 2025 is used in combination with an R2-70 Iowa curve.

Illustrative Example of Use of a Life Span
Original and Smooth Survivor Curves
IOWA 70 -R3 (Interim Survivor Curve)
Conceptual Pattern of Terminal Retirements
Truncation at End of Year 2025
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
120
Age in Years
Period of Interim or Ongoing Retirements
Period of Terminal or Final Retirements

YUB-YECL-82

Reference: Deferral on depreciation parameters, process to determine whether a change in depreciation parameters may be required, YECL Application, pages 7-2 and 7-3

Yukon Electrical is requesting approval for a deferral account to allow it the ability to file future applications, as necessary, to change its depreciation parameters within the 2013-2015 test period, and flow through the impact of any such change to customers within the test period.

If a significant change has occurred, but not only in the current year but over a few years (i.e.2 to 3) that cannot be discounted as being a non-typical transaction and appears to be a valid retirement pressure that is supported by the appropriate engineers and management, than a new depreciation parameter may be warranted.

Request:

(a) Please explain why the above-noted request may not be considered as retroactive ratemaking?

(b) Would the YECL request to potentially change depreciation parameters shift forecast risk for this item form YECL to customers?

(c) The timing required to detect a significant change extends beyond the requested test period. Would it be more efficient then to propose changes to depreciation parameters in a subsequent GRA?

(d) YECL has stated that, “each change in depreciation parameters must be assessed on an individual basis with regard to materiality”. Please provide YECL’s views of what those materiality guidelines should be.

Response:

(a) This deferral account should not be considered retroactive ratemaking as it is simply requesting the opportunity to reflect in rates the impact of updated depreciation parameters potentially more often than what would have been necessary prior to the advent of IFRS. In the past, depreciation studies were filed in regular intervals to update depreciation parameters. These updated

depreciation parameters were filed with regulators, tested, approved and ultimately reflected in both the GAAP and regulatory books of the utility. The only thing that has changed in today's IFRS environment is that IFRS requires depreciation parameters to be reviewed on an annual basis. This means there is now a risk that there will be different depreciation parameters for IFRS and utility purposes if there is not an opportunity to update utility depreciation parameters at the same time as they are changed for IFRS purposes.

(b) As detailed in Section 7 of its Application, the intention of Yukon Electrical's requested deferral is, to the extent possible, to permit Yukon Electrical to harmonize IFRS and regulatory accounting and avoid the administrative burden of keeping two sets of financial records. As such, there is no shifting of forecast risk for this item from Yukon Electrical to customers.

Significant changes in the expected life of assets or gross salvage and costs of retirement of assets can be caused by various events, including a change in technology. Such an event or events could have an immediate impact on the expected life of assets or gross salvage and costs of retirement in the same year in which in which it occurs. Conversely, such event or events could have an impact on the expected life of assets or gross salvage and costs that is not immediate but is only revealed after several years of data and trend information is analyzed. Yukon Electrical would be required to update its depreciation parameters if either type of situation were to occur.

If a material change is warranted upon Yukon Electrical's annual review of depreciation parameters as described on pages 7-2 and 7-3 of the Application, Yukon Electrical would be obligated to adjust its depreciation parameters and the resulting depreciation rates and expense for that year for financial statement purposes in order to obtain a clean audit opinion under IFRS. While the update to the depreciation parameters for regulatory purposes could wait until Yukon Electrical's next GRA is filed, the delay would create a situation where there Yukon Electrical would be managing two separate sets of books for property plant and equipment.

Yukon Electrical would only update its depreciation parameters if the resulting impact on depreciation expense was large enough to require adjustment for financial statement purposes. Such a change would have to be greater than $100,000.

YUB-YECL-83

Reference: Depreciation, YECL Application, Schedules 7-1 to 7-5 inclusive

Request:

(a) Please restate the Section 7 schedules, using the methods and Iowa curves approved in YECL's 2008-09 GRA.

(b) In schedule 7.5, please fully explain the transition from ($382,000) to $71,000 (2012 Actual to 2013 Forecast) for the total amortization of differences.

Response:

(a) Please refer to YUB-YECL-83(a) Attachment 1.

(b) The amortization of differences is developed using the forecast life and net salvage parameters for each fixed asset account. Using the forecast life and net salvage parameters assumes that these parameters have been in existence since day 1 for each fixed asset account and determines a calculated accrued depreciation to the date of the depreciation study. This calculated accrued depreciation is then compared to the actual booked accumulated depreciation. If the booked value is greater than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account, as an annual provision for true-up, resulting in an annual depreciation expense decrease. Similarly, if the booked value is less than +/- 5% of the calculated value, the difference is amortized over the remaining life of the fixed asset account resulting in an annual depreciation expense increase. Thus, the difference between the previous depreciation study amount of ($382,000) to the current depreciation study amount of $71,000 reflects depreciation parameter forecast changes.

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.1 - Depreciation Expense
Using 2008/2009 Depreciation Parameters

Line No.	Description	Cross Ref.	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1	General Provision	S. 7.2, 7.3,7.4 L.51	3,585	3,892	4,108	4,559	4,641	5,529	6,386	7,173	3,760	4,067
2	Amortization of Differences	S.7.5 L. 51	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)	(382)
3	Vehicle Depreciation Capitalized	S.8.6 L. 21	(22)	(64)	(43)	(48)	(67)	(75)	(82)	(87)	(24)	(24)
4	Total Depreciation Expense	S.1.1 L.12	3,181	3,446	3,683	4,129	4,192	5,072	5,922	6,704	3,354	3,661

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.2 - 2013 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2013 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2013 Total Depreciation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		263	3.33%	9	180	3	12
4	423 00	Hydro Resv, Dams & Waterways		2,375	3.57%	85	1,627	29	114
5	425 00	Hydro Generators		2,676	3.76%	101	1,833	34	135
6	426 00	Hydro Accessory Electrical Equip		158	3.24%	5	108	2	7
7	427 00	Hydro Misc Equip		69	3.70%	3	47	1	4
8		Total Production - Hydro		5,539		203	3,794	69	272
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,238	2.71%	61	491	7	68
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,138	2.97%	93	688	10	103
13	445 00	Generating Equipment & Prime Mover - Other		7,270	3.59%	261	1,594	29	290
14	446 00	Accessory Electric Equipment - Other		2,077	2.94%	61	455	7	68
15	447 00	Misc. Power Plant Equipment - Other		794	3.11%	25	174	3	28
16		Total Production - Diesel		15,517		501	3,402	56	557
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.49%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,331	1.51%	20	102	1	21
24	473 00	Poles, Towers & Fixtures		34,533	2.67%	922	2,559	34	956
25	474 00	Overhead Conductor		22,282	2.67%	595	1,703	23	618
26	474 10	Services - Overhead		2,979	2.59%	77	228	3	80
27	475 00	Underground Conductor		22,880	2.41%	551	1,732	21	572
28	475 10	Services - Underground		3,097	2.10%	65	237	2	67
29	476 10	Meters		1,984	4.10%	81	542	-	81
30	476 30	AMR - Meters		68	4.52%	3	-	-	3
31	477 10	Substation Equipment		3,131	2.77%	87	239	3	90
32	478 10	Street Lighting		9,600	3.98%	382	396	8	390
33	478 20	Sentinel Lights		285	2.99%	9	-	-	9
34	479 10	Line Transformers		28,058	3.03%	850	2,032	31	881
35		Total Distribution Plant		130,227		3,642	9,770	126	3,768
36									
37		General Plant							
38	482 00	Structures & Improvements		3,634	3.10%	113	1,124	17	130
39	483 00	Office Furniture & Equipment		194	5.70%	11	11	-	11
40	483 20	Computer Equipment		47	18.73%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		2,954	9.34%	276	432	20	296
42	485 00	Tool & Work Equipment		843	6.33%	53	86	3	56
43	486 00	Communication Structures & Equipment		938	5.50%	52	65	2	54
44	488 20	Company Housing		475	2.66%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,251	4.00%	-	650	26	26
47	493 00	Demand Side Management		-	10.00%	-	481	48	48
48	496 00	Software		2,204	10.00%	220	705	35	255
49		Total General Plant		12,541		747	3,555	151	898
50									
51		Plant Studied		165,208		5,127	20,522	402	5,529
52		Plant Not Studied - Land		380					
53		Total Plant	S.8.6 L.10	165,588					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.3 - 2014 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2014 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2014 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		442	3.54%	16	157	3	19
4	423 00	Hydro Resv, Dams & Waterways		4,001	3.68%	147	1,421	26	173
5	425 00	Hydro Generators		4,508	3.79%	171	1,601	30	201
6	426 00	Hydro Accessory Electrical Equip		266	3.49%	9	94	2	11
7	427 00	Hydro Misc Equip		116	4.06%	5	41	1	6
8		Total Production - Hydro		9,334		348	3,315	62	410
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		2,729	2.72%	74	649	9	83
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,826	2.97%	114	910	14	128
13	445 00	Generating Equipment & Prime Mover - Other		8,865	3.88%	344	2,109	41	385
14	446 00	Accessory Electric Equipment - Other		2,532	2.97%	75	602	9	84
15	447 00	Misc. Power Plant Equipment - Other		968	3.11%	30	230	4	34
16		Total Production - Diesel		18,919		637	4,501	77	714
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.48%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,432	1.50%	21	113	1	22
24	473 00	Poles, Towers & Fixtures		37,092	2.67%	990	2,844	38	1,028
25	474 00	Overhead Conductor		23,985	2.67%	640	1,887	25	665
26	474 10	Services - Overhead		3,206	2.59%	83	252	3	86
27	475 00	Underground Conductor		24,612	2.40%	591	1,921	23	614
28	475 10	Services - Underground		3,334	2.10%	70	262	3	73
29	476 10	Meters		2,525	4.11%	104	(377)	-	104
30	476 30	AMR - Meters		68	4.50%	3	1,580	36	39
31	477 10	Substation Equipment		3,370	2.79%	94	265	4	98
32	478 10	Street Lighting		9,996	3.96%	396	945	19	415
33	478 20	Sentinel Lights		285	2.93%	8	-	-	8
34	479 10	Line Transformers		30,090	3.03%	912	2,364	36	948
35		Total Distribution Plant		139,997		3,912	12,057	188	4,100
36									
37		General Plant							
38	482 00	Structures & Improvements		4,758	3.14%	149	315	5	154
39	483 00	Office Furniture & Equipment		205	6.67%	14	9	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		3,386	9.50%	322	868	41	363
42	485 00	Tool & Work Equipment		930	6.67%	62	137	5	67
43	486 00	Communication Structures & Equipment		1,003	6.67%	67	11	-	67
44	488 20	Company Housing		475	2.65%	13	-	-	13
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		481	10.00%	48	522	26	74
48	496 00	Software		2,909	10.00%	291	7	-	291
49		Total General Plant		16,096		1,051	1,869	77	1,128
50									
51		Plant Studied		185,730		5,982	21,742	404	6,386
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	186,110					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule 7.4 - 2015 Depreciation
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	2015 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2015 Total Deprecation
1		Production - Hydro							
2									
3	422 00	Hydro Structures		600	3.61%	22	-	-	22
4	423 00	Hydro Resv, Dams & Waterways		5,422	3.71%	201	-	-	201
5	425 00	Hydro Generators		6,110	3.79%	232	-	-	232
6	426 00	Hydro Accessory Electrical Equip		360	3.57%	13	-	-	13
7	427 00	Hydro Misc Equip		157	4.10%	6	-	-	6
8		Total Production - Hydro		12,649		474	-	-	474
9									
10		Production - Diesel							
11	442 00	Structures and Improvements - Other		3,378	2.78%	94	798	11	105
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		4,736	2.99%	142	1,118	17	159
13	445 00	Generating Equipment & Prime Mover - Other		10,973	3.91%	429	2,592	51	480
14	446 00	Accessory Electric Equipment - Other		3,134	3.01%	94	740	11	105
15	447 00	Misc. Power Plant Equipment - Other		1,198	3.14%	38	283	4	42
16		Total Production - Diesel		23,420		797	5,531	94	891
17									
18		Transmission							
19	457 00	Substation Equipment		1,384	2.47%	34	-	-	34
20		Total Transmission		1,384		34	-	-	34
21									
22		Distribution Plant							
23	471 00	Land Rights		1,545	1.50%	23	109	1	24
24	473 00	Poles, Towers & Fixtures		39,937	2.67%	1,066	2,736	37	1,103
25	474 00	Overhead Conductor		25,872	2.67%	691	1,825	24	715
26	474 10	Services - Overhead		3,459	2.60%	90	244	3	93
27	475 00	Underground Conductor		26,534	2.40%	637	1,855	22	659
28	475 10	Services - Underground		3,596	2.10%	76	254	3	79
29	476 10	Meters		2,148	4.10%	88	(377)	-	88
30	476 30	AMR - Meters		1,648	4.54%	75	2,283	52	127
31	477 10	Substation Equipment		3,636	2.80%	102	256	4	106
32	478 10	Street Lighting		10,941	3.97%	434	813	16	450
33	478 20	Sentinel Lights		285	2.87%	8	-	-	8
34	479 10	Line Transformers		32,454	3.03%	983	2,277	34	1,017
35		Total Distribution Plant		152,054		4,273	12,274	196	4,469
36									
37		General Plant							
38	482 00	Structures & Improvements		5,073	3.13%	159	305	5	164
39	483 00	Office Furniture & Equipment		214	6.67%	14	2	-	14
40	483.20	Computer Equipment		47	20.00%	9	-	-	9
41	484 00	Transportation & Mobile Equipment		4,254	9.87%	420	730	36	456
42	485 00	Tool & Work Equipment		1,066	6.67%	71	84	3	74
43	486 00	Communication Structures & Equipment		1,014	6.67%	68	12	-	68
44	488 20	Company Housing		475	2.63%	12	-	-	12
45	491 00	Franchise & Consent		1	0.00%	-	-	-	-
46	492 00	Licence - Fish Lake		1,901	4.00%	76	-	-	76
47	493 00	Demand Side Management		1,003	10.00%	100	730	37	137
48	496 00	Software		2,916	10.00%	292	57	3	295
49		Total General Plant		17,965		1,221	1,920	84	1,305
50									
51		Plant Studied		207,472		6,799	19,725	374	7,173
52		Plant Not Studied -Land		380					
53		Total Plant	S.8.6 L.10	207,852					

The Yukon Electrical Company Limited
2013 - 2015 General Rate Application
Revised Schedule of Amortization of Differences
Using 2008/2009 Depreciation Parameters

Line No.	Acct.	Description	Cross Ref.	YFR/ Curve	Life	Net Salvage	Depn. Rates	Actual 2011	Actual 2012	Test Period 2013	Test Period 2014	Test Period 2015	GRA Approved 2008	GRA Approved 2009
1		Production - Hydro												
2														
3	422 00	Hydro Structures		R2	72	-10%	3.36%	(14)	(14)	(14)	(14)	(14)	(14)	(14)
4	423 00	Hydro Resv, Dams & Waterways		R3	103	-10%	3.36%	-	-	-	-	-	-	-
5	425 00	Hydro Generators		R3	85	-10%	3.36%	-	-	-	-	-	-	-
6	426 00	Hydro Accessory Electrical Equip		R3	45	-10%	3.36%	-	-	-	-	-	-	-
7	427 00	Hydro Misc Equip		R2	30	-10%	3.36%	-	-	-	-	-	-	-
8		Total Production - Hydro						(14)	(14)	(14)	(14)	(14)	(14)	(14)
9														
10		Production - Diesel												
11	442 00	Structures and Improvements - Other		R2.5	40	-10%	2.74%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
12	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		R4	35	-20%	3.00%	(8)	(8)	(8)	(8)	(8)	(8)	(8)
13	445 00	Generating Equipment & Prime Mover - Other		R2.5	26	-10%	3.69%	(40)	(40)	(40)	(40)	(40)	(40)	(40)
14	446 00	Accessory Electric Equipment - Other		R3	35	0%	3.00%	(15)	(15)	(15)	(15)	(15)	(15)	(15)
15	447 00	Misc. Power Plant Equipment - Other		R3	40	0%	3.15%	(2)	(2)	(2)	(2)	(2)	(2)	(2)
16		Total Production - Diesel						(71)	(71)	(71)	(71)	(71)	(71)	(71)
17														
18		Transmission												
19	457 00	Substation Equipment		R4	50	-10%	2.55%	(3)	(3)	(3)	(3)	(3)	(3)	(3)
20		Total Transmission						(3)	(3)	(3)	(3)	(3)	(3)	(3)
21														
22		Distribution Plant												
23	471 00	Land Rights		R3	75	0%	1.52%	-	-	-	-	-	-	-
24	473 00	Poles, Towers & Fixtures		R3	45	-75%	2.67%	(75)	(75)	(75)	(75)	(75)	(75)	(75)
25	474 00	Overhead Conductor		R4	45	-80%	2.69%	(24)	(24)	(24)	(24)	(24)	(24)	(24)
26	474 10	Services - Overhead		R3	45	-10%	2.62%	(7)	(7)	(7)	(7)	(7)	(7)	(7)
27	475 00	Underground Conductor		R3	45	-50%	2.11%	(5)	(5)	(5)	(5)	(5)	(5)	(5)
28	475 10	Services - Underground		R4	40	-10%	2.63%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
29	476 10	Meters		L0	15	0%	4.06%	-	-	-	-	-	-	-
30	476 30	AMR - Meters		R2.5	15	0%	4.54%							
31	477 10	Substation Equipment		R4	40	-10%	2.92%	(6)	(6)	(6)	(6)	(6)	(6)	(6)
32	478 10	Street Lighting		R3	30	-10%	4.13%	(61)	(61)	(61)	(61)	(61)	(61)	(61)
33	478 20	Sentinel Lights		R2	23	0%	3.37%	-	-	-	-	-	-	-
34	479 10	Line Transformers		R3	45	-10%	3.04%	(69)	(69)	(69)	(69)	(69)	(69)	(69)
35		Total Distribution Plant						(253)	(253)	(253)	(253)	(253)	(253)	(253)
36														
37		General Plant												
38	482 00	Structures & Improvements		L3	40	0%	3.19%	-	-	-	-	-	-	-
39	483 00	Office Furniture & Equipment		SQ	15	0%	4.49%	2	2	2	2	2	2	2
40	483.20	Computer Hardware/Software		SQ	5	0%	20.00%	-	-	-	-	-	-	-
41	484 00	Transportation & Mobile Equipment		L0	12	25%	10.82%	(51)	(51)	(51)	(51)	(51)	(51)	(51)
42	485 00	Tool & Work Equipment		SQ	15	0%	6.54%	(3)	(3)	(3)	(3)	(3)	(3)	(3)
43	486 00	Communication Structures & Equipment		SQ	15	0%	5.79%	11	11	11	11	11	11	11
44	488 20	Company Housing		R3	40	10%	2.47%							
45	491 00	Franchise & Consent					0.00%	-	-	-	-	-	-	-
46	492 00	Licence - Fish Lake					10.00%							
47	493 00	Demand Side Management												
48	496 00	Software		S3	10	0%	10.00%	-	-	-	-	-	-	-
49		Total General Plant						(41)	(41)	(41)	(41)	(41)	(41)	(41)
50														
51		Total Amortization of Differences	S. 7.1 L. 2					(382)	(382)	(382)	(382)	(382)	(382)	(382)

YUB-YECL-84

Reference: Average life curves, YECL Application, Section 7, Attachment 1, page 31 of 208

In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit … It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group, assuming no contrary relevant factors external to the analysis of historical data.

Request:

(a) What is used to determine which curve gives the best fit? Is a goodness-of-fit test or some other statistical method used to make the determination? Please explain.

(b) If statistics are not the only factor used in determining the best fitting curve, what weighting is given to statistical analysis versus "contrary relevant factors"?

Response:

(a) Gannett Fleming employed a visual fitting process, which includes the following steps:

1. The observed life table as determined in the Retirement rate analysis is plotted in accordance with the procedures as described at pages II-10 through II-23 of the Gannett Fleming report;

2. The areas of the observed life table that the analyst considered to represent data points that are representative of future retirement causes and expectations are determined for each account, giving consideration to:

   i. placing reduced emphasis on the tail portion of the observed life table (generally once plant exposed to retirement is less than 1% of total plant exposed to retirement at age 0);

   ii. placing reduced emphasis on the early portion of the life curve; and

iii. identification of any unusual data points in the observed life table at any age and determination of the reasons for retirement causing the unusual data point;

3. A statistically determined best fit is determined through the calculation of the sum of least squared differences procedure. In this procedure, the variance of each actual data point determined in the retirement rate analysis is compared to the corresponding data point of the smoothed Iowa curve through the calculation of a residual measure in which each variance is squared and the squared differences are summed. The square root of the sum of the squared differences is known as the residual measure of the fit of the smoothed curve to the observed life table; and

4. The statistical best fit (as determined above) for each family of curves is plotted against the observed life table. In addition, a number of smoothed Iowa curves are plotted against the observed life table through the period of most reliance to allow the depreciation analyst to visually inspect the smoothed Iowa curve against the plotted observed life table.

While this process begins with the determination of a best fit curve determined through the calculation of the residual measures, the statistical fitting process does not provide any weighting of the observed life table data points. Therefore, the statistical best fits are only used as a starting point for the remainder of the curve fitting process, in order that the analyst can place appropriate weighting on the various segments of the observed life table.

(b) Please refer to YUB-YECL-84(b) Attachment 1 which is a summary of the relative weighting assigned to each of the factors considered in the average service life analysis for each account.

THE YUKON ELECTRICAL COMPANY LIMITED

SUMMARY OF RELATIVE WEIGHTING APPLIED TO VARIOUS CONSIDERATION IN THE AVERAGE SERVICE LIFE ESTIMATATION

	DESCRIPTION	RECOMMENDED SURVIVOR CURVE	PREVIOUSLY RECOMMENDED CURVE	RETIREMENT RATE ANALYSIS	PEER ANALYSIS	MANAGEMENT AND OPERATING INTERVIEWS	GANNETT FLEMING EXPERIENCE	COMMENTS
	(1)	(2)	(4)	(5)	(6)=(5)/(3)			
GENERATION								
HYDRO GENERATION (LIFE SPAN OF 2052)								
422.00	HYDRO STRUCTURES	72-R2	none	none	high	medium	medium	
423.00	HYDRO RESERVOIRS, DAMS AND WATERWAYS	103-R3	none	none	high	medium	medium	Due to lack of specific retirement information the average service lives as recently approved for YEC were adopted as the recommended life to YECL in this study for all Hydro Generation accounts
425.00	HYDRO GENERATORS	85-R3	none	none	high	medium	medium	
426.00	HYDRO ACCESSORIES AND EQUIPMENT	45-R3	none	none	high	medium	medium	
427.00	HYDRO MISCELLANEOUS EQUIPMENT	30-R2	none	none	high	medium	medium	
DIESEL GENERATION								
442.00	STRUCTURES AND IMPROVEMENTS	40-R2.5	medium	medium	low	high	medium	Little actual retirement experience
444.00	FUEL HOLDERS, PRODUCTS AND ACCESSORIES	35-R4	high	high	low	high	medium	
445.00	GENERAL EQUIPMENT AND PRIME MOVERS	26-S2.5	high	high	low	high	medium	
446.00	ACCESSORY ELECTRIC EQUIPMENT	35-R3	high	high	low	high	medium	
447.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40-R3	high	low	low	high	medium	Little actual retirement experience
SUBSTATION PLANT								
457.00	SUBSTATION EQUIPMENT - TRANSMISSION	50-R4	medium	medium	medium	medium	medium	
DISTRIBUTION PLANT								
471.00	LAND RIGHTS	75-R3	high	none	high	medium	medium	Account has no actual retirement experience
473.00	POLES, TOWERS AND FIXTURES	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
474.00	OVERHEAD CONDUCTOR	45-R4	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
474.10	OVERHEAD SERVICES	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
475.00	UNDERGROUND CONDUIT	45-R3	medium	low	medium	medium	medium	Little actual retirement experience
475.10	UNDERGROUND SERVICES	40-R4	medium	medium	medium	medium	medium	Little actual retirement experience
476.10	METERS	15-L0	low	medium	medium	high	high	
476.30	AMR - METERS	15-R2.5	none	low	high	high	high	
477.10	SUBSTATION EQUIPMENT - DISTRIBUTION	40-R4	medium	low	medium	high	medium	Little actual retirement experience
478.10	STREET LIGHTS AND SIGNAL SYSTEMS	30-R3	medium	medium	medium	medium	low	
478.20	SENTINEL LIGHTS	23-R2	medium	medium	medium	medium	low	
479.10	LINE TRANSFORMERS	45-R3	medium	medium	medium	medium	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
GENERAL PLANT								
482.00	STRUCTURES AND IMPROVEMENTS	40-L3	high	medium	medium	high	medium	Recommendation is a moderated fit between the actual retirement experience and current curve
483.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	medium	none	medium	high	high	
483.20	COMPUTER EQUIPMENT AND ACCESSORIES	5-SQ	high	none	high	high	medium	
484.00	TRANSPORTATION AND MOBILE EQUIPMENT	12-L0	medium	high	medium	high	low	
485.00	TOOLS AND INSTRUMENTS	15-SQ	high	none	medium	high	medium	
486.00	COMMUNICATION EQUIPMENT	15-SQ	high	none	medium	high	medium	
488.20	HOUSES	40-R3	high	none	low	medium	medium	Account has no actual retirement experience

YUB-YECL-85

Reference: Survivor curve judgments, YECL Application, Section 7, Attachment 1, page 31 of 208

The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and engineering staff, and survivor curve estimates form previous studies of this Company and other electric distribution companies.

Request:

Please explain why any weighting should be given to other distribution companies.

Response:

In the development of average service life estimates, consideration should be given to all forces of retirement that can be reasonably expected to occur. In order to forecast the forces of retirement, a number of estimation "tools" are available, including the review of historic retirement experience, discussions with operations and management representatives, industry experience, upcoming capital programs and experience gained from the review of relevant peer companies. In this manner, the depreciation analyst can form an average service life or net salvage estimate based on a wide variety of input. The weighting provided to each of these inputs is provided in response to information request YUB-YECL-84(b) Attachment 1.

With specific reference to the use of peer information, it should be noted that it provided additional weighting in circumstances where the company has a limited amount of actual retirement experience, and where peer companies have experienced relevant retirement activity. Additionally, Gannett Fleming uses the peer analysis as a benchmark for the determination of the reasonableness of the average service life and net salvage analysis developed from the use of other analysis tools. In this manner, the use of peers is not the primary estimation method, but rather a check of reasonableness. In circumstances where average life or net salvage parameters determined with company specific information are out of the range of the peer analysis, further interview and discussions are held with company representatives to determine the potential reasons that the company retirement history would differ from that of the peers.

YUB-YECL-86

Reference: Asset accounts, YECL Application, Section 7, Attachment 1, pages 31 of 208 to 35 of 208

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 1983 through 2011, and in part through a comparison to peer electric distribution companies.

The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation.

Request:

(a) For each of the asset accounts listed, please provide a table that shows the Iowa curve previously used and approved by the Board, the Iowa curve recommended in this application, the corresponding depreciation rates previously approved and now recommended, and if there is a change an explanation of the primary factor for that change from what was approved to what is being recommended.

(b) In general, does a change in the Iowa curve from a 50-RX to a 45-RX imply a change in expected service life form 50 years to 45 years?

(c) For Account 475.00 the change from Iowa 50-R4 to Iowa 45-R3 is "to better fit industry retirement trends". What curve best represents YECL's retirement trends for that asset class?

(d) For account 478.10, the Iowa curve has been changed from an Iowa 25-R3 to an Iowa 30-R3 "to better fit industry retirement trends". Please define the industry, the trend, and the location of that industry and how those locations are an appropriate match for a location such as Yukon.

(e) Please explain why the retirement history for Accounts 422.00 through 427.00 were not available. What was used in past studies for YECL?

Response:

(a) Please refer to YUB-YECL-86(a) Attachment 1, which identifies the primary factor for the material change from what was approved in the last depreciation study to what is being recommended for the Iowa curve and depreciation rates in this application.

(b) Confirmed, given the context of the example where the survivor curve shape (i.e. RX) remains constant and the average service life differs.

(c) The curve that best represents Yukon Electrical's retirement trends for the asset class of 475.00 is within the range of the electric distribution systems peer analysis (YUB-YECL-87(a)). The recommended Iowa curve appears to be trending towards a shorter survivor curve shape amongst Yukon Electrical's peers and within the range of Yukon Energy Corporation's approved Iowa curve.

(d) Please refer to the response to information request YUB-YECL-87. The analysis focused on a number of northern Canadian regulated distribution systems including Yukon Energy Corporation.

(e) Given the amount of investment in the hydro generation accounts, and further given the very limited amount of retirement history, in prior studies it was determined that the accounts could be analyzed and depreciated as one group. However, during the early stages of this current study, it was identified that some of the operating components will have an identifiably differing life expectation and replacement of some of the components is now likely in the near term. Therefore, during the preparation of this study, it was determined that the expected consumption of service value for this group of investment is better estimated through the analysis of the accounts individually.

The Yukon Electrical Company Limited
Comparison of Approved Iowa Curves and Depreciation Rates to Proposed Iowa Curves and Depreciation Rates

Acct.	Description	GRA Approved Iowa Curve	Recommended Iowa Curve	GRA Approved Depreciation Rate	Recommended Depreciation Rate	Explanation
	Production - Diesel					
442 00	Structures and Improvements - Other	40-R2.5	40-R2.5	3.07%	3.13%	Age Surviving Balance
444 00	Fuel Holders, Producers, & Acc. Equipment - Other	35-R4	35-R4	3.69%	3.80%	Age Surviving Balance
445 00	Generating Equipment & Prime Mover - Other	27-R2.5	26-S2.5	4.24%	4.34%	Change in Average Service Life Estimate
446 00	Accessory Electric Equipment - Other	35-R3	35-R3	3.32%	3.52%	Age Surviving Balance
447 00	Misc. Power Plant Equipment - Other	35-R3	40-R3	2.92%	2.96%	Change in Average Service Life Estimate
	Transmission					
457 00	Substation Equipment	40-R4	50-R4	2.25%	2.25%	-
	Distribution Plant					
471 00	Land Rights	75-R3	75-R3	1.51%	1.50%	-
473 00	Poles, Towers & Fixtures	40-R3	45-R3	4.20%	4.20%	-
474 00	Overhead Conductor	40-R3	45-R4	4.16%	4.16%	-
474 10	Services - Overhead	40-R3	45-R3	2.57%	2.58%	-
475 00	Underground Conductor	50-R4	45-R3	3.61%	3.61%	-
475 10	Services - Underground	40-R4	40-R4	2.87%	2.86%	-
476 10	Meters	n/a	15-L0	7.65%	8.09%	Change in Average Service Life Estimate
476 30	AMR - Meters	25-S2	15-R2.5	7.31%	7.13%	Change in Average Service Life Estimate
477 10	Substation Equipment	35-R3	40-R4	2.75%	2.75%	-
478 10	Street Lighting	25-R3	30-R3	3.77%	3.75%	Change in Average Service Life Estimate
478 20	Sentinel Lights	23-R2	23-R2	2.99%	2.93%	-
479 10	Line Transformers	35-R3	45-R3	2.66%	2.65%	-
	General Plant					
482 00	Structures & Improvements	32-R4	40-L3	2.63%	2.67%	Age Surviving Balance
483 00	Office Furniture & Equipment	15-SQ	15-SQ	5.70%	6.67%	Completion of true-up correction
483 20	Computer Equipment	5-SQ	5-SQ	18.73%	20.00%	Completion of true-up correction
484 00	Transportation & Mobile Equipment	10-R0.5	12-L0	6.44%	6.59%	Age Surviving Balance
485 00	Tool & Work Equipment	15-SQ	15-SQ	6.33%	6.67%	Completion of true-up correction
486 00	Communication Structures & Equipment	15-SQ	15-SQ	5.50%	6.67%	Completion of true-up correction
488 20	Company Housing	40-R3	40-R3	2.93%	2.91%	-

YUB-YECL-87

Reference: Estimation of net salvage, YECL Application, Section 7, Attachment 1, pages 35 to 37 of 208

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 1983 through 2011, and in part through a comparison to peer electric distribution companies.

The net salvage percentages estimated in this study have been determined using the "Traditional Approach" for net salvage estimation.

Request:

(a) Please list the peer distribution companies and the weighting given to each company.

(b) Please confirm whether the "Traditional Approach" conforms with past directions form this Board.

(c) Please provide a table showing for each asset account, the approved net salvage percentages approved in the 2008-09 YECL GRA and the net salvage percentages recommended in the current application.

Response:

(a) Please refer to YUB-YECL-87(a) Attachment 1 for a list of peer distribution companies. Gannett Fleming does not assign any specific weighting to each company in the peer analysis. The peer analysis tool is a guide in formulating the reasonableness of a range in order to test whether the preliminary recommendation falls within the range of currently approved parameters.

(b) Confirmed. In previous applications, the request for net salvage has been prepared using the "traditional approach".

(c) Please refer to YUB-YECL-87(c) Attachment 1 for a table of the net salvage percentages approved in the 2008-09 Yukon Electrical GRA along with the net salvage percentages recommended of this current application.

YUKON ELECTRICAL COMPANY LIMITED - RECOMMENDED CURVES AND PEER ANALYSIS

YUKON ELECTRICAL COMPANY LIMITED - Peer Life Analysis

Account		Current Curves 2008	NB Power Corporation 0	ATCO Electric 2010	Yukon Energy Corporation 2012	Manitoba Hydro 2012	Fortis Alberta 2011	Fortis BC 2011	Northland Utilities Yellowknife 2004	Northland Utilities 2011	Best Fit	Recom-mended Curves
	HYDRAULIC PRODUCTION ASSETS											
42000	Hydraulic Production	30-R3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		40-R4
	DIESEL PRODUCTION ASSETS											
44200	Structures and Improvements	40-R2.5	n/a	n/a	72-R2	n/a	n/a	n/a	n/a	n/a		40-R2.5
44400	Fuel holders, Products and Acc.	35-R4	n/a	n/a	25-R2	n/a	n/a	n/a	n/a	n/a		35-R4
44500	Generating Equipment and Prime Movers	27-R2.5	n/a	n/a	40-R2	n/a	n/a	n/a	n/a	n/a		26-S2.5
44600	Accessory Electric Equipment	35-R3	n/a	n/a	45-R3	n/a	n/a	n/a	n/a	n/a		35-R3
44700	Miscellaneous power Plant Equipment	35-R3	n/a	n/a	30-R2	n/a	n/a	n/a	n/a	n/a		40-R3
	TRANSMISSION ASSETS											
45700	Substation Equipment	40-R4	27-R2/35-R2	53-R3	54-S0	35-R2/45-R2	n/a	50-S4	31.R3	45-R4		50-R4
	DISTRIBUTION ASSETS											
47100	Land Rights	75-R3	30-SQ	75-R3	n/a	75-R3	36-L3	75-R3	75-R3	75-R3		75-R3
47300	Poles and Fixtures	40-R3	33-R1/34-R1.5	45-R2.5	35-R2	55-R3	45-R1.5	50-R3	45-R4	44-R4		45-R3
47400	Overhead Conductors	40-R3	40-R3/40-R1	55-R2.5	35-R2	60-R2	45-R1.5	45-R3	40-R4	50-R3		45-R4
47410	Overhead Services	40-R3	40-R3/40-R1	50-R4	40-R2	60-R2	n/a	45-R3	40-R3	50-R3		45-R3
47500	Underground Conduit	50-R4	35-L1	55-R4	40-R2.5	75-R4	58-R2	n/a	50-R3	59-R3		45-R3
47510	Underground Services	40-R4	35-R3/35-R4	50-R3	40-R2.5	45-R4/60-R4	n/a	n/a	40-R3	35-R3		40-R4
47610	Meters	n/a	22-R2	20-R1.5	30-R2	20-R1.5/25-R3	n/a	20-R1	20-L0.5	16-L0		15-L0
47630	AMR Meters	25-S2	27-R1.5	15-R2.5	n/a	20-R1.5/25-R3	15-R0.5	n/a	n/a	n/a	14-O4	15-R2.5
47710	Substation Equipment	35-R3	27-R2/35-R2	50-R3	40-R2	35-R2/45-R2	n/a	55-S3	31-R3	50-R2		40-R4
47810	Streetlighting & Signal Sytems	25-R3	33-R0.5	43-R4	40-R2	35-R3	20-R1	40-R4	35-S2.5	35-S3	59-R3	30-R3
47820	Sentinel Lights	23-R2	20-L0	31-R1	30-L2	n/a	n/a	n/a	n/a	30-S1.5		23-R2
47910	Lines Transformers	35-R3	25-R1/30-R3	40-R2.5	40-R2.5	50-R2	n/a	45-R4	35-S2.5	33-R3		45-R3
	GENERAL PLANT ASSETS											
48200	Structures and Improvements	32-R4	15-SQ/75-R2	55-R3	40-R2.5	65-R4	10-SQ	40-R3/35-R3	38-S2	45-R3	40-S2	40-L3
48300	Office Furniture and Equipment	15-SQ	15-SQ	15-R3	20-SQ	20-SQ	15-SQ	15-SQ	15-S4	15-SQ	14-S2.5	15-SQ
48320	Computers	5-SQ	6-SQ	5-S0.5	5-SQ	5-SQ/10-SQ	5-R4/7-SQ	10-SQ/5-SQ	5-R4	5-SQ	4-L1	5-SQ
48400	Vehicles and Mobile Heavy Equipment	10-R0.5	6-S3/17-L1.5	10-L1.5/25-R3	7-L2/25-R1.5	9-L2/35-R3	5-L1/3-SQ/14-S4	8-L3/20-L3	7-L2/26-R3	20-L1		12-L0
48500	Tools and Instruments	15-SQ	15-SQ	10-R2	20-SQ	15-SQ	10-SQ	15-SQ	10-S3	10-SQ	11-L3	15-SQ
48600	Communication and Structures	15-SQ	12-L4	25-R2	20-L4	n/a	n/a	15-SQ	15-R4	20-L3		15-SQ
48820	Houses	40-R3	n/a	12-L0	30-R3	n/a	n/a	n/a	n/a	n/a		40-R3

Notes:

1. NB Power refers to this account as Dusk to Dawn
2. A life span expiring at June 30, 2020.

YUKON ELECTRICAL COMPANY LIMITED - RECOMMENDED NET SALVAGE PERCENTAGE

YUKON ELECTRICAL COMPANY LIMITED - Peer Net Salvage Percentage Analysis

Account		Recom-mended Net Salv % 08/09 GRA	Approved Net Salv % 08/09 GRA	NB Power Corporation 2006	ATCO Electric 2010	Yukon Energy Corporation 2012	Manitoba Hydro 2012	Fortis Alberta 2011	Fortis BC 2011	Northland Utilities Yellowknife 2004	Northland Utilities 2011	Best Fit %'age	Recom-mended %'age	Comments
	HYDRAULIC PRODUCTION ASSETS													
42000	Hydraulic Production	-10	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		-10	
	DIESEL PRODUCTION ASSETS													
44200	Structures and Improvements	0	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-10	revised Jan 18 2013 as per site visit
44400	Fuel holders, Products and Acc.	-30	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-20	revised Jan 18 2013 as per site visit
44500	Generating Equipment and Prime Movers	-10	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		-10	
44600	Accessory Electric Equipment	0	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		0	
44700	Miscellaneous power Plant Equipment	-5	0	n/a	n/a	0	n/a	n/a	n/a	n/a	n/a		0	
	TRANSMISSION ASSETS													
45700	Substation Equipment	0	0	0	-10	0	0	n/a	0	-11.9	-10		-10	revised Jan 18 2013 as per site visit
	DISTRIBUTION ASSETS													
47100	Land Rights	0	0	0	0	n/a	0	0	0	0	0		0	
47300	Poles and Fixtures	-60	0	0	-50	0	0	0	0	-35	-50		-75	
47400	Overhead Conductors	-70	0	0	-65	0	0	0	0	-30	-55		-80	
47410	Overhead Services	0	0	0	0	0	0	n/a	0	-10	-10		-10	revised Jan 18 2013 as per site visit
47500	Underground Conduit	-5	0	0	-10	0	0	0	n/a	0	-5		-50	
47510	Underground Services	0	0	0	0	0	0	n/a	n/a	0	-5		-10	revised Jan 18 2013 as per site visit
47610	Meters	0	0	0	0	0	0	n/a	0	1	0		0	
47630	AMR Meters	0	0	0	0	n/a	0	0	0	n/a	n/a		0	
47710	Substation Equipment	0	0	0	-5	0	0	n/a	0	-10	-5		-10	
47810	Streetlighting & Signal Sytems	-10	0	0	-10	0	0	-15	0	-5	0		-10	
47820	Sentinel Lights	10	0	0	20	0	n/a	n/a	0	n/a	20		0	
47910	Lines Transformers	-5	0	0	5	0	0	n/a	0	-30	-5		-10	
	GENERAL PLANT ASSETS													
48200	Structures and Improvements	5	5	0	-5	0	0	5/10	0	5	0		0	
48300	Office Furniture and Equipment	0	0	0	0	0	0	0	0	0	0		0	
48320	Computers	0	0	0	0	0	0	0	0	0	0		0	
48400	Vehicles and Mobile Heavy Equipment	20	20	0	10/20	0	0	15	20	25/15	20		25	
48500	Tools and Instruments	0	0	0	0	0	0	0	0	0	0		0	
48600	Communication and Structures	0	0	0	0	0	0	n/a	0	2	0		0	
48820	Houses	10	10	n/a	85	n/a	n/a	n/a	n/a	n/a	n/a		-10	

YUB-YECL-88

Reference: Results of study, YECL Application, Section 7, Attachment 1, page 43 of 208

An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service.

The service life and net salvage estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities.

Request:

(a) For the first quote above, please define "a long period of time". Would consistent accrual rates imply accuracy and a reasonable estimation of average service life for an asset?

(b) Why would any consideration be given to estimates made for other electric utilities?

Response:

(a) Normally depreciation studies are completed every 3 to 5 years for utilities of the size of Yukon Electrical. Gannett Fleming would view that a "long period of time" would be a period of longer than 5 years. Additionally, Gannett Fleming notes that consistent accrual rates that remain unchanged for periods of longer than 5 years do not necessarily imply accuracy and a reasonable estimation of average service life for an asset. In circumstances where accrual rates remain unchanged for long periods of time without any type of review or study, the accrual rate should not be considered as correct. However, accrual rates that remain consistent after having been studied likely represent a reasonable estimation of average service life.

(b) Please refer to the response to information request YUB-YECL-85.

YUB-YECL-89

Reference: Additional evidence, YECL Application, Section 7, Attachment 2

Request:

Was this additional evidence provided at the request of YECL? Please explain.

Response:

During the initial phases of the depreciation study, Yukon Electrical asked Gannett Fleming to provide an indication of whether any events have transpired since the Board's Decision regarding the inclusion of net salvage percentages that may support the reinstatement of net salvage percentages in the current study. In response to this request, Gannett Fleming embarked upon a process to research this issue among Canadian regulatory jurisdictions. Based on this research, it was Gannett Fleming's view that a number of significant events had transpired that support the inclusion of net salvage. Accordingly, Yukon Electrical requested that the Additional Evidence addressing this issue be prepared.

YUB-YECL-90

Reference: Inclusion of net salvage in the depreciation rate calculations, YECL Application, Section 7, Attachment 2

Request:

(a) To clarify, when net salvage is included in depreciation rates, are customers therefore currently paying for a service (salvage) or part thereof, which would occur in the future, and whose final cost is an estimate subject to change?

(b) Do accounting guidelines, MFRs or other rules or regulations delineate the use of depreciation parameters and FRSR policies based on type of ownership (Crown versus private)

(c) If FRSR balances are a current recovery for a future service (salvage), should such balances or contributions earn a return until said services are performed?

(d) If FRSR contributions are based on estimates, who is at risk for any variances between actual and forecast results? Please explain.

Response:

(a) Net salvage is an estimate of the future gross salvage received for property retired minus the future cost of retirement for plant retired, demolished, or removed. Negative net salvage is an estimated cost that will be incurred in the future on facilities that are being used to provide utility service to customers today, and as such, it helps to maintain generational equity, by ensuring that customers are paying for the full cost of receiving service at the time it is being provided. To not do so would result in inter-generational inequity in that future customers would pay for costs associated with facilities that were used to provide service to past customers.

(b) No.

(c) No. Yukon Electrical does not earn a return on FRSR balances prior to said services being performed. As detailed in Schedules 8.5 and 8.6 of its Application, a reinstatement of net negative salvage for Yukon Electrical results

in an increase to the forecast depreciation expense, an increase to the forecast accumulated depreciation and a reduction to the overall forecast rate base. As such, the inclusion of net negative salvage results in a lower rate base as compared to if net negative salvage was not included in Yukon Electrical's revenue requirement.

Please refer to YUB-YECL-90(c) Attachment 1 for Yukon Electrical's forecast rate base and return on rate base for 2013-2015 both including and excluding net negative salvage, which illustrates that the inclusion of net negative salvage results in a lower rate base.

(d) Net salvage parameters are reviewed at each GRA for applicability and accuracy to the future gross salvage and cost of retirement costs. These forecasts are vetted, tested and approved at each GRA. As such, these forecasts are based on the best information available to Yukon Electrical at the time and ensures that customers pay only the cost associated with assets required to provide utility service; no less and no more.

The Yukon Electrical Company Limited
Comparison of Rate Base and Return Including and Excuding Net Salvage

	As Filed Using 2013/2015 Proposed Depreciation Parameters - With Net Salvage	Using 2013/2015 Proposed Depreciation Parameters - No Net Salvage
2013		
Rate Base	72,329	73,312
Return on Rate Base	5,308	5,382
2014		
Rate Base	86,063	89,075
Return on Rate Base	6,255	6,473
2015		
Rate Base	96,812	102,028
Return on Rate Base	7,003	7,378